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Design of Reliable Industrial and Commercial Power Systems

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IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems

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Power Systems Reliability Subcommittee
of the
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Abstract: The fundamentals of reliability analysis as it applies to the planning and design of industrial and commercial electric power distribution systems are presented. Included are basic concepts of reliability analysis by probability methods, fundamentals of power system reliability evaluation, economic evaluation of reliability, cost of power outage data, equipment reliability data, and examples of reliability analysis. Emergency and standby power, electrical preventive maintenance, and evaluating and improving reliability of the existing plant are also addressed. The presentation is self-contained and should enable trade-off studies during the design of industrial and commercial power systems. Design, installation, maintenance practices for electrical power and grounding (including both power-related and signal-related noise control) of sensitive electronic processing equipment used in commercial and industrial applications are presented.

Keywords: designing reliable industrial and commercial power systems, equipment reliability data, industrial and commercial power systems reliability analysis, reliability analysis

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Introduction

This introduction is not part of IEEE Std 493-2007, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems.

The objective of this recommended practice is to present the fundamentals of reliability analysis applied to the planning and design of industrial and commercial electric power distribution systems. The intended audience for this material is primarily consulting engineers and plant engineers, and technicians. The design of reliable industrial and commercial power distribution systems is important because of the high cost associated with power outages. It is necessary to consider the cost of power outages when making design decisions for new and existing power distribution systems as well as to have the ability to make quantitative "cost-versus-reliability" trade-off studies. The lack of credible data concerning equipment reliability and the cost of power outages has hindered engineers in making such studies. This revision of IEEE Std 493™ overcomes these obstacles by providing extensive mechanical and electrical equipment reliability data; complete U.S. Army Corp of Engineers Power Reliability Enhancement Program (PREP) database, recent cost of power outage data, data collection procedures for maintenance and equipment failures, 7 × 24 continuous power analysis, and voltage sag analysis are presented. Detailed examples of reliability analysis of various industrial distribution system operating configurations are presented. The authors of this book have attempted to provide sufficient information so that reliability analyses can be performed on industrial and commercial power systems without requiring cross-references to other texts.

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IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems

Chapter 1
Introduction

1.1 Objectives and scope

The objective of this book is to present the fundamentals of reliability analysis applied to the planning and design of industrial and commercial electric power distribution systems. The intended audience for this material is primarily consulting engineers and plant electrical engineers and technicians.

The design of reliable industrial and commercial power distribution systems is important because of the high cost associated with power outages. It is necessary to consider the cost of power outages when making design decisions for new power distribution systems as well as to have the ability to make quantitative “cost-versus-reliability” trade-off studies. The lack of credible data concerning equipment reliability and the cost of power outages has hindered engineers in making such studies. This revision of IEEE Std 493™ overcomes these obstacles.

The authors of this book have attempted to provide sufficient information so that reliability analyses can be performed on industrial and commercial power systems without requiring cross-references to other texts. Included are the following:

- Basic concepts of reliability analysis by probability methods
- Fundamentals of power system reliability evaluation
- Economic evaluation of reliability
- Recent cost of power outage data
- **New** extensive mechanical and electrical equipment reliability data—Complete U.S. Army Corp of Engineers Power Reliability Enhancement Program (PREP) database
- Examples of reliability analysis of various industrial distribution system operating configurations
- 7 × 24 continuous power
- Voltage sag analysis

- Emergency and standby power
- Evaluating and improving the reliability of existing electrical system
- Preventative maintenance
- Reliability and maintainability verification
- Standard data collection techniques

The following chapters present a detailed discussion of factors that impact the planning and design of industrial and commercial power systems:

Chapter 2: Basic concepts of reliability
Chapter 3: Planning and design
Chapter 4: Evaluating and improving the reliability of an existing electrical system
Chapter 5: Preventative maintenance
Chapter 6: Emergency and standby power
Chapter 7: Voltage sag analysis
Chapter 8: 7 × 24 continuous power facilities
Chapter 9: Reliability and maintainability verification
Chapter 10: Summary of equipment reliability data
Chapter 11: Data collection

The appendixes (renamed *annexes*) of IEEE Std 493-1997[1] are included in this revision of the *IEEE Gold Book*™. One new annex, Annex Q, has been added to provide additional informative material on the reliability analysis of industrial and commercial power systems.

Several new reliability concepts [i.e., inherent availability (Ai) and operational availability (Ao)] are introduced in this version of the *IEEE Gold Book*. The inherent frequency and duration of load point interruptions is used to compare designs based on the mean time to repair (MTTR) a component. The MTTR a component is defined as only the average time to repair that component but does not include the logistics time (e.g., to identify and isolate the component on forced outage). The operational frequency and duration of load point interruptions includes the mean downtime (MDT) (i.e., the mean duration of the component maintenance and forced outage events). Other reliability studies define the operational frequency and duration of load point interruptions where the MDT excludes the maintenance downtimes (Mdts). These concepts are presented in detail in Chapter 2.

1.2 Summary of contents of each chapter

Chapter 2 provides the theoretical background for the reliability analysis used in other chapters. Some basic concepts of probability theory are discussed as these are essential to

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[1] Information on references can be found in 1.4.

the understanding and development of quantitative reliability analysis methods. Definitions of terms commonly used in system reliability analysis are also included.

Chapter 3 provides a description of how to make quantitative reliability and availability predictions for proposed new and existing configurations of industrial power distribution systems. A discussion is presented on the important factors that must be considered in the reliability analysis of industrial and commercial power systems. The *Gold Book Standard Network* configuration and the results of various reliability methodologies are presented to enable validation of existing and future reliability computerized methodologies. Seven numerical examples are presented and a reliability-cost/reliability-worth methodology presented. The latest survey data on the cost of interruptions to various facilities is presented. A quantitative reliability analysis includes making a disciplined evaluation of alternate power distribution system design choices. When costs of power outages at the various building and plant locations are factored into the evaluation, the decisions can be based upon *total owning cost* over the useful life of the equipment rather than simply the *first cost* of the system. The material in this book should enable engineers to make more use of quantitative cost vs. reliability trade-off studies during the design of industrial and commercial power systems.

The objective of Chapter 4 is to provide the facility engineer with critical issues that should be analyzed from various perspectives considering their system electrically and physically and inquiring about the utility's system. The chapter provides a list of issues that the engineer should address:

a) See that faults are properly isolated and that critical loads are not vulnerable to interruption or delayed repair.
b) Analyze the critical areas and evaluate the need for special restoration equipment, spare parts, or procedures.
c) Based on probability and economic analysis, make capital or preventive maintenance investments as indicated by the analysis.
d) Make carefully documented contingency (catastrophe) plans.
e) Check the quality of the power supply from the utility and throughout the plant to determine if the equipment is vulnerable to premature failure.
f) Develop preventive maintenance, checking, and logging procedures to ensure continuous optimum reliability performance of the plant.

The objective of Chapter 5 is to illustrate the important role preventative maintenance plays in the availability of systems in industrial plants and commercial buildings. Details of "when," "how," and "how often" can be obtained from other sources that are defined in the chapter. Of the many factors involved in availability, preventive maintenance often receives meager emphasis in the design phase and operation of distribution systems when it can be a key factor in high availability. Large expenditures for systems are made to provide the desired reliability; however, failure to provide timely, high-quality preventive maintenance leads to system or component malfunction or failure and prevents obtaining the intended design goal.

Chapter 6 presents an overview of common types of emergency and standby power systems used by most industries to achieve increased reliability in power supply to loads. No attempt is made to list and describe every type of existing system that may be classified as an emergency or standby power system. For example, fuel cells continue to be developed and researched for a wide range of applications. At this time, however, most would agree their cost prohibits attractive practical use in general industrial and commercial applications for emergency and standby power.

Chapter 7 presents a method for voltage sag coordination that is an important improvement in the power quality field. The procedure enables customers, utilities, and equipment manufacturers to quantify the performance of their process, supply, or device. This will no doubt lead to a better understanding of spurious trips and an improvement in performance.

Chapter 8 presents a *reliability block diagram* (RBD) methodology to conduct a probability/reliability study of a 7 × 24 continuous power facility. Momentary interruptions of the electrical power can have huge financial consequences. The chapter provides a methodology of defining *failure* in a 7 × 24 facility**.** Specialty equipment, such as uninterruptible power supplies (UPS), emergency generators, and automatic static transfer switches (ASTS) are used to supplement utility power and are discussed in detail in this chapter.

Chapter 9 presents a generalized sequential test plan for demonstrating whether a power system and/or its parts comply with the specifications dictated by the customer and manufacturer. The number of observed system failures vs. the number of tests required for compliance evaluation is shown graphically. The methodology provides a means of estimating the number of tests required to demonstrate reliability compliance of devices and systems.

Chapter 10 summarizes the reliability data collected from equipment reliability surveys and a data collection program over a period of 35 years or more. This data is the most comprehensive database publicly available on electrical and mechanical equipment reliability in the world. The reliability survey data contained in this book provide historical experience to those who have not been able to collect their own data. Such data can be an aid in analyzing, designing, or redesigning an industrial or commercial system and can provide a basis for the quantitative comparison of alternate designs.

Chapter 11 presents the standard data collection techniques that include the essential categories of information and data essential for reliability modeling including maintenance activities. Categories such as site identification, site one-line drawings, nameplate information, critical equipment designation and sparing, and maintenance data are discussed, and the necessary data collection forms presented. The information contained in the data collected provides the analyst with all the necessary data to populate a reliability model.

1.3 How to use this book

The authors of this book have made it a self-contained body of knowledge in which reliability analyses can be performed on industrial and commercial power systems without requiring cross-references to other texts. Each chapter addresses the critical issues affecting the reliability of industrial and commercial power distribution systems. For example, those wishing to obtain the latest equipment reliability and maintainability data should go directly to Chapter 10 and wishing to obtain the most recent data on the cost of electrical interruptions to industrial plants or commercial buildings should consult Chapter 3. Chapter 11 provides the standard data collection techniques to capture the reliability data at any industrial and/or commercial facility. The summary of chapter content in 1.2 provides a guide for users to address their specific concerns in the reliability analysis of their industrial and commercial power systems.

1.4 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 493-1997, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems *(IEEE Gold Book)*.[2]

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[2] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

Chapter 2
Basic concepts of reliability

2.1 Introduction

This chapter provides the theoretical background for the reliability analysis used in other chapters. Some basic concepts of probability theory are discussed, as these are essential to the understanding and development of quantitative reliability analysis methods. Definitions of terms commonly used in system reliability analysis are also included.

2.2 Definitions

For the purpose of this document, the following terms and definitions apply. *The Authoritative Dictionary of IEEE Standards Terms* [B3][1] should be referenced for terms not defined in this subclause.

Some commonly used terms in system reliability analyses are defined here; these terms are also used in the wider context of system reliability activities. These definitions are referenced in several reliability publications and the formulas can be verified in the Reliability Analysis Center's *Reliability Toolkit: Commercial Practices Edition,* page 12 [B7], or MIL-STD-339 [B5].

2.2.1 availability: The ability of an item—under combined aspects of its reliability, maintainability, and maintenance support—to perform its required function at a stated instant of time or over a stated period of time.

2.2.2 component: A piece of electrical or mechanical equipment viewed as an entity for the purpose of reliability evaluation.

2.2.3 failure (f): The termination of the ability of a component or system to perform a required function.

2.2.4 failure rate (λ): The mean (arithmetic average) is the number of failures of a component and/or system per unit exposure time. The most common unit in reliability analyses is hours (h) or years (y). Therefore, the failure rate is expressed in failures per hour (f/h) or failures per year (f/y). *Syn:* **forced outage rate.**

2.2.5 inherent availability (Ai): The instantaneous probability that a component or system will be up or down. Ai considers only downtime for repair to failures. No logistics time, preventative maintenance, etc., is included.

2.2.6 maintenance downtime (Mdt): The total downtime for scheduled maintenance (including logistics time, spare parts availability, crew availability, etc.) for a given time period (**Tp**) (hours).

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[1] The numbers in brackets correspond to those of the bibliography in 2.11.

2.2.7 mean downtime (MDT): The average downtime caused by scheduled and unscheduled maintenance, including any logistics time. *Syn:* **mean time to restore system (MTTRS).**

2.2.8 mean time between failures (MTBF): The mean exposure time between consecutive failures of a component.

2.2.9 mean time between maintenance (MTBM): The average time between all maintenance events, scheduled and unscheduled, and also includes any associated logistics time.

2.2.10 mean time to failure (MTTF): The mean exposure time between consecutive repairs (or installations) of a component and the next failure of that component. MTTF is commonly found for non-repairable items such as fuses or bulbs.

2.2.11 mean time to maintain (MTTM): The average time it takes to maintain a component, including logistics time. MTTM is primarily a measure of the preventative maintenance frequency and durations.

2.2.12 mean time to repair (MTTR or simply r): The mean time to replace or repair a failed component. Logistics time associated with the repair, such as parts acquisitions, crew mobilization, are not included. It can be estimated by dividing the summation of repair times by the number of repairs and, therefore, is practically the average repair time. The most common unit in reliability analyses is hours (h/f).

2.2.13 operational availability (Ao): The instantaneous probability that a component or system will be up or down, but differs from Ai in that it includes *all* downtime. Included is downtime for unscheduled (repair due to failures) and scheduled maintenance, including any logistics time.

2.2.14 reliability: The ability of a component or system to perform required functions under stated conditions for a stated period of time.

NOTE—The term *reliability* is also used as a reliability characteristic (metric) denoting a probability of success or a success ratio. In general usage, reliability refers to system performance over time.[2]

2.2.15 repair downtime (Rdt): The total downtime for unscheduled maintenance (excluding logistics time) for a given **Tp** (hours).

2.2.16 repair logistics time (Rlt): The total logistics time for unscheduled maintenance for a given **Tp** (hours).

2.2.17 system: A group of components connected or associated in a fixed configuration to perform a specified function.

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[2] Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement the standard.

2.2.18 total downtime events (Tde): The total number of downtime events (including scheduled maintenance and failures) during the **Tp** (previously referred to as *all actions, maintenance, and repair*).

2.2.19 total failures (Tf): The total number failures during the **Tp**.

2.2.20 total maintenance actions (Tma): The total number of scheduled maintenance actions during the **Tp**.

2.2.21 total period (Tp): The calendar time over which data for the item was collected (hours).

2.2.22 year (y): The unit of time measurement approximately equal to 8765.81277 hours (h). Any rounding of this value will have adverse effects on analyses depending on the magnitude of that rounding; 8766 is used commonly as it is the result of rounding to 365.25 × 24 (which accounts for a leap year every 4th year); 8760, which is 365 × 24, is the most commonly used value in power reliability field. By convention, 8760 will be used throughout this recommended practice.

2.3 Calculation reference

A summary of the definitions is compiled in Table 2-1. This table is supplied for your quick reference for some of the formulas that are provided with definition later in the chapter. These calculations are also useful in the Chapter 10.

Table 2-1—Definition summary

Calculated data	Formula for calculation
Ai, inherent availability	Ai = MTBF/(MTBF + MTTR)
Ao, operational availability	Ao = MTBM/(MTBM + MDT)
λ, failure rate (f/h)	λ = Tf / Tp
λ, failure rate (f/y)	λ = Tf / (Tp / 8760)
MDT, mean downtime (h)	MDT = (Rdt + Rlt + Mdt) / Tde
MTBF, mean time between failures (h)	MTBF = Tp / Tf
MTBM, mean time between maintenance (h)	MTBM = Tp / Tde
MTTM, mean time to maintain (h)	MTTM = Mdt / Tma
MTTR, mean time to repair (h)	MTTR = r = Rdt / Tf
R(*t*), reliability	$R(t) = e^{-\lambda t}$

Table 2-1—Definition summary *(continued)*

Calculated data	Formula for calculation
Downtime hours per year (DHY)	DHY = $(1 - Ao) \times 8760$
λr, downtime hours per year (DHY)	DHY = λr, where λ is the failure rate per year

2.4 Acronyms and abbreviations

Ai	inherent availability
Ao	operational availability
ASTS	automatic static transfer switch
CDF	cumulative distribution function
FMEA	failure mode and effects analysis
Mdt	maintenance downtime
MDT	mean downtime
m-g	motor-generator
MTBF	mean time between failures
MTBM	mean time between maintenance
MTTF	mean time to failure
MTTR	mean time to repair
O&M	operations and maintenance
PDF	probability density function
PDU	power distribution unit
RBD	reliability block diagram
RCM	reliability centered maintenance
Rdt	repair downtime
Rlt	repair logistics time

SPOF	single point of failure
Tde	total downtime events
Tf	total failures
Tma	total maintenance actions
Tp	total period

2.5 Review of basic probability

2.5.1 Sample space

Sample space is the set of all possible outcomes of a phenomenon. For example, consider a system of three components. Assuming that each component exists either in the operating or “up” state or in the failed or “down” state, consider the sample space:

S = (1U, 2U, 3U), (1D, 2U, 3U), (1U, 2D, 3U), (1U, 2U, 3D), (1D, 2D, 3U), (1D, 2U, 3D), (1U, 2D, 3D), (1D, 2D, 3D)

Where iU and iD denote that the component i is up or down, respectively. The possible outcomes of a system are also called *system states*, and the set of all possible system states is called *system state space*.

2.5.2 Event

In the example of the three-component system, the descriptions (1D, 2D, 3U), (1D, 2U, 3D), (1U, 2D, 3D), and (1D, 2D, 3D) define the events in which two or three components are in the failed state. Assuming that a minimum of two components is needed for successful system operation, this set of states (A) also defines the system failure. A is, therefore, a set of system states, and the event A(N) is said to have occurred if the system is in a state that is a member of set A.

2.5.3 Combinatorial properties of event probabilities

Follows are certain combinatorial properties of event probabilities that are useful in reliability analysis.

2.5.3.1 Addition rule of probabilities

Two events, A1 and A2, are mutually exclusive if they cannot occur together. For events A1 and A2 that are not mutually exclusive (that is, events which can happen together), see Equation (2.1).

$$P(A1 \cup A2) = P(A1) + P(A2) - P(A1 \cap A2) \tag{2.1}$$

where

$P(A1 \cup A2)$ is the probability of A1 or A2, or both happening

$P(A1 \cap A2)$ is the probability of A1 and A2 happening together

When A1 and A2 are mutually exclusive, they cannot happen together; that is, $P(P(A1 \cap A2)) = 0$, therefore Equation (2.1) reduces to Equation (2.2):

$$P(A1 \cup A2) = P(A1) + P(A2) \tag{2.2}$$

Where A1 and A2 are mutually exclusive.

2.5.3.2 Multiplication rule of probabilities

If the probability of occurrence of event A1 is affected by the occurrence of A2, then A1 and A2 are not independent events.

The conditional probability of event A1, given that event A2 has already occurred, is denoted by $P(A1|A2)$ and Equation (2.3):

$$P(A1 \cap A2) = P(A1|A2)P(A2) \tag{2.3}$$

Equation (2.4) is also used to calculate the conditional probability:

$$P(A1|A2) = P(A1 \cap A2)/P(A2) \tag{2.4}$$

When, however, events A1 and A2 are independent, that is, the occurrence of A2 does not affect the occurrence of A1, use Equation (2.5):

$$P(A1 \cap A2) = P(A1\ \ )P(A2) \tag{2.5}$$

2.5.3.3 Complementation

$A'1$ is used to denote the complement of event A1. The complement $A'1$ is the set of states that are not members of A1. For example, if A1 denotes states indicating system failure, then the states not representing system failure make $A'1$ [see Equation (2.6)].

$$P(A'1) = 1 - P(A1) \tag{2.6}$$

2.6 Reliability and availability

In the reliability engineering discipline, the terms *reliability* and *availability* have specialized technical meanings. In general, reliability refers to system performance over time. And unfortunately, reliability is often shorthand for *reliability engineering* and its practice, results, etc. Reliability engineering is a design engineering discipline that applies scientific knowledge to assure a product will perform its intended function for the required duration within a given environment. This includes designing in the ability to maintain, test, and support the product throughout its total life cycle. This is accomplished concurrently with other design disciplines by contributing to the selection of the system architecture, materials, processes, and components—both software and hardware—followed by verifying the selections made by thorough analysis and test. Availability generally refers to the quality or state of being immediately ready for use.

2.6.1 General concepts

The term *reliability* refers to the notion that the system performs its specified task correctly for a certain time duration. The term *availability* refers to the *readiness* of a system to immediately perform its task—at a particular time. Both terms have precise definitions within reliability engineering discipline and typically have specified equations or methods to provide quantitative metrics for each of them. A rocket must be very reliable for the duration of the short mission, but might not be very available as it may sit in a repair state for extended periods of time.

On the other hand, power for communications facilities needs to be highly available, implying little downtime. Where the components of the system might be unreliable, the redundancies of that system can help achieve high availability.

2.6.2 Definitions

2.6.2.1 Reliability

If the time, t, over which a system must operate and the underlying distributions of failures for its constituent elements are known, then the system reliability can be calculated by taking the integral, essentially the area under the curve defined by the probability density function (PDF, see 2.9), from t to infinity, as shown in Equation (2.7).

$$R(t) = \int_t^{\infty} f(t)dt \tag{2.7}$$

where

$R(t)$ is the reliability of a system from time t to infinity
$f(t)$ is the PDF

2.6.2.2 Availability

2.6.2.2.1 Availability assumptions

Generally in this document, availability will be used as a mathematical term being either the percent of time a system is immediately ready for use, or as an instantaneous probability of the system being immediately ready for use.

Generally, availability metrics fall into two distinct subsets: *inherent availability* (Ai) and *operational availability* (Ao). Ai considers component failure rates and the average repair time for those components. Ao goes beyond Ai in that maintenance downtimes (Mdt), parts procurement times, logistics, etc., are included. Although Ao provides a "truer" availability of a system, Ai provides a metric that is not tainted by local facility characteristics, such as spare part supplies, planned outages, etc. Ai is useful as a common metric for comparing multiple facilities and measuring particular facilities against a predetermined availability goal.

Availability analyses need to have an explicit listing of the assumptions used for each unique analysis. For example, if a facility will go down for maintenance, but the outage is not deemed critical, then that outage might not be included in that analysis. On the other hand, if a mission critical facility has a planned maintenance event on a redundant piece of equipment, then that planned outage could be included to capture the additional exposure to risk as the redundancy of the system is temporarily lost.

2.6.2.2.2 Inherent availability definition

In general, availability is immediate readiness for use. For this recommended practice, we only consider Ai and calculate the metric for Ai explicitly as shown in Equation (2.8):

$$\mathrm{Ai} = \frac{\mathrm{MTBF}}{\mathrm{MTBF} + \mathrm{MTTR}} \tag{2.8}$$

where

MTBF is mean time between failures
MTTR is mean time to repair

If the system never failed, the MTBF would be infinite and Ai would be 100%. Or, if it took no time at all to repair the system, MTTR would be zero and again the availability would be 100%. Figure 2-1 is a graph showing availability as a function of MTBF and MTTR [availability is calculated using Equation (2.8)]. Note that you can achieve the same availability with different values of MTBF and MTTR. With lower MTBF, lower levels of MTTR are needed to achieve the same availability and vice versa.

2.6.2.2.3 Inherent availability misinterpretations/limitations

Power availability metrics tend to be reported as a function of "9's." This refers to the quantity of 9's past the decimal point. A facility with an availability of 0.99999 would be referred to as having 5-9's.

A common misunderstanding—and misuse—of the metric is the interpretation that a mean downtime (MDT) can be extracted from an availability metric. For example, a common proclamation is that a facility that has achieved 5-9's availability can expect an average downtime of approximately 5 min per year. It is mathematically true that the system will be down an average of 5 min per year over the long run, i.e., as $t \to \infty$. However, if MTBF is known, or calculated a priori, to be 87 660 h (10 y), then the expected duration of the outage will be 52 min.

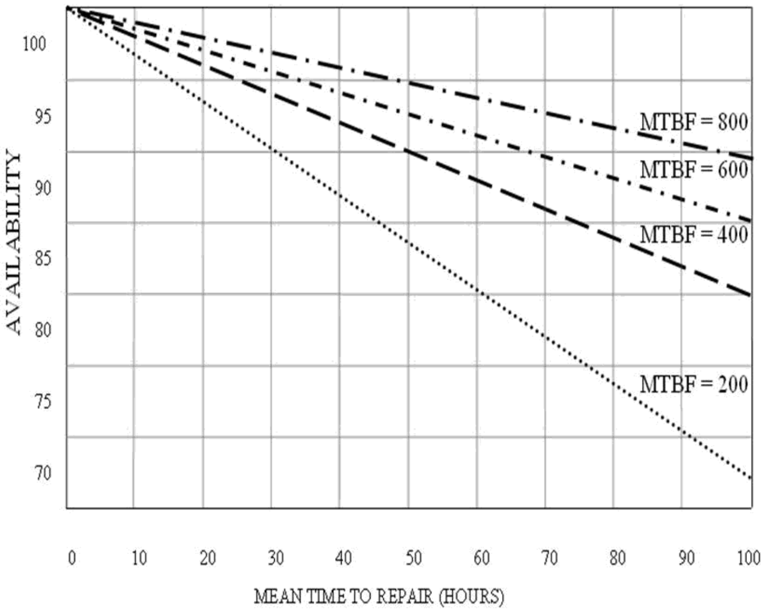

Figure 2-1—Different combinations of MTBF and MTTR yield the same availability

Essentially, an availability metric is a ratio of two parameters. As made clear in 2.6.2.2.2, given an availability metric, there are infinite MTBF and MTTR metrics that can yield the same availability metric. Thus, if availability of a system is estimated through modeling, great care must be taken in extracting system MTBF and MTTR metrics.

2.7 Defining frequency and duration of outages and interruptions, λ, MTBF

The definitions and assumptions associated with frequency and duration data are critical to effectively measuring the reliability of a power system. The choice of metric used to define outages and repair times is dependent on the data used to generate the statistic, which leads to the proper distribution function (see 2.8).

2.7.1 Frequency of failures, outages

Historically, frequency was synonymous with the failure rate (or MTBF), which implied the exponential distribution attribute of having a constant failure rate with randomly occurring events throughout the life of the component or system. The failure distribution of few components is random—to be described by the exponential distribution. Its popularity is a function of the fact that it is the best distribution given the data that is available for most power components.

As data collection efforts continue, time to failure data, coupled with the maintenance practices on that equipment, will produce data that can be tested for best fit for a multiple of distributions, primarily the Weibull (see 2.8.5).

2.7.2 Duration of outages and interruptions

Similarly, the duration of outages has historically been described as the MTTR—implying the exponential distribution. This, again, was due to a lack of detailed data. In considering descriptive statistics to represent the duration of outages, the assumptions, such as the inclusion if scheduled repairs, logistics, spare parts availability, must be explicitly stated.

2.8 Probability distributions

Probability distributions are mathematical equations that describe the probability of a particular event occurring with respect to time. For reliability analysis, what is of great interest is the probability distribution of failure. These functions capture failure characteristics such as wearout failure modes, infant mortality, random, etc. The most common distribution for power reliability analyses (the term *reliability* used in the general sense, as described in 2.6.1) is the exponential distribution. This function describes a random failure mode, where the MTBF is the critical parameter. Others are the Weibull, the Lognormal, etc.

2.8.1 Probability density functions

Each probability distribution has unique PDFs with the notation *f(t)*. The area under that curve shows the relative probability of a failure occurring before time *t* (see Figure 2-2). That probability, which becomes the cumulative distribution function (CDF), can be calculated by the integral shown in Equation (2.9):

$$F(t) = \int_{o}^{t} f(t)dt \tag{2.9}$$

where

F(t)	is the probability of a failure occurring before time *t*
f(t)	is the PDF of failure

2.8.2 Cumulative distribution function

Plotting *F(t)* gives us the CDF, which shows the probability of a failure occurring at time *t* (see Figure 2-3).

Finally, the reliability function *R(t)* is the probability if a component not failing by time *t*. Therefore *R(t)* = 1 – *F(t)*.

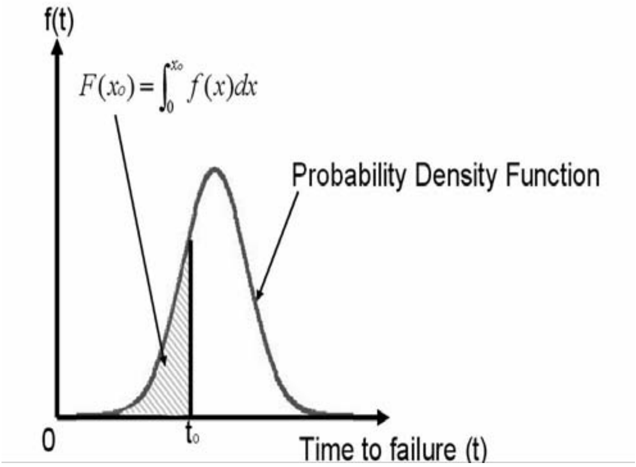

Figure 2-2—Probability of a failure represented by the area under the curve of the PDF

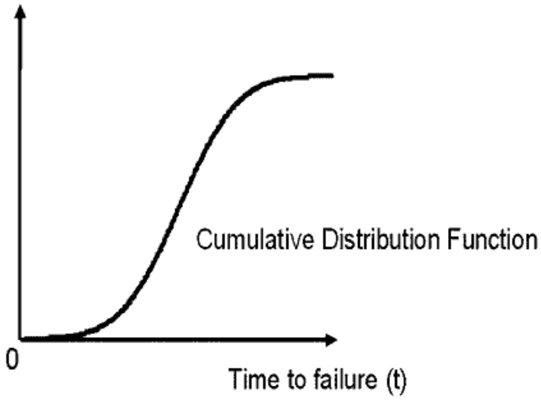

Figure 2-3—The cumulative distribution

2.8.3 Hazard function

The hazard function, or hazard rate, is the instantaneous failure rate for the remaining population at time *t.* It is denoted as shown in Equation (2.10):

$$H(t) = \frac{f(t)}{R(t)} \tag{2.10}$$

2.8.4 Exponential distribution

The PDF for the exponential distribution is shown in Equation (2.11):

$$f(t) = \lambda e^{-\lambda t} \tag{2.11}$$

Thus, the CDF is shown in Equation (2.12):

$$f(t) = 1 - e^{-\lambda t} \tag{2.12}$$

And the reliability function is shown in Equation (2.13):

$$R(t) = e^{-\lambda t} \tag{2.13}$$

where

λ is the failure rate (inverse of MTBF)
t is the length of time the system must function
e is the base of natural logarithms

It can be seen that the hazard function is as shown in Equation (2.14):

$$H(t) = \frac{\lambda e^{-\lambda t}}{e^{-\lambda t}} = \lambda \tag{2.14}$$

This is to be expected, as the instantaneous failure rate is constant for the exponential distribution.

The most essential characteristic of the exponential distribution, which is the common PDF in availability analyses, is that the failure rate is constant over time—the component is no more likely to fail in its first year of life then it is in its 21st year of life. It should not be assumed that all components exhibit this characteristic. Most do not. Its popularity is a function of the fact that it is the best PDF given the data that supports the reliability metrics of most power components. Essentially, the exponential requires only the MTBF, which can be easily determined by a total component run time and a total of component failure events.

2.8.5 Weibull distribution

The Weibull distribution is one of the most widely used in life data distribution analysis. It is a versatile distribution that can take on the characteristics of other types of distributions, based on the value of the shape parameter beta (β). When $\beta > 1$ then a wearout failure mode is present. When $\beta < 1$ then the part exhibits infant mortality. When $\beta = 1$, then the Weibull distribution is mathematically equal to the *exponential distribution,* implying a random failure mode. The eta (η) parameter is a “location” factor. Where the beta parameter tells us how the part is going to fail, the eta parameter tells us when.

2.8.5.1 2PDF and CDF

Equation (2.15) shows the Weibull PDF:

$$f(t,\beta,\eta) = \frac{\beta}{\eta}\left(\frac{t}{\eta}\right)^{\beta-1} e^{-\left(\frac{t}{\eta}\right)^{\beta}} \tag{2.15}$$

where

ß is the shape parameter
η is the location parameter

Equation (2.16) shows the Weibull CDF:

$$f(t,\beta,\eta) = 1-e^{-\left(\frac{t}{\eta}\right)^{\beta}} \tag{2.16}$$

The hazard function for the Weibull distribution is shown in Equation (2.17):

$$H(t,\beta,\eta) = \beta t^{\beta-1} \tag{2.17}$$

When β = 1, the Weibull distribution is equal to the exponential distribution, as shown in Equation (2.18):

$$F(t, 1, \eta) = 1 - e -(t/\eta)1 = 1 - e - (t/\eta) \tag{2.18}$$

Note the variety in PDF shapes depending on the choice of β, as shown in Figure 2-4.

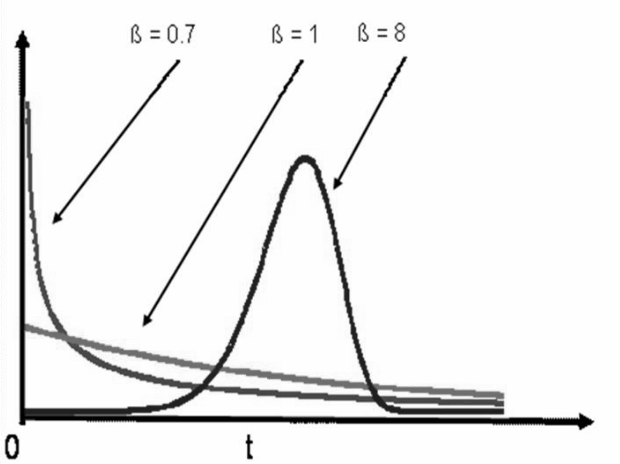

Figure 2-4—Variation of the beta parameter

2.8.6 Calculating reliability for the exponential

If the underlying distribution for each element is exponential and the failure rates, λi, for each element are known, then the reliability of the system can be calculated using Equation (2.13).

2.8.6.1 Series reliability

Consider the system represented by the reliability block diagram (RBD) in Figure 2-5.

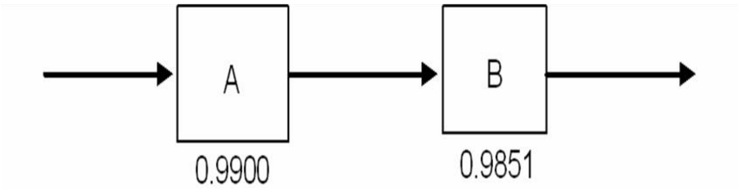

Figure 2-5—Example reliability block diagram

Note—The number above each block in Figure 2-5 is the failure rate λ in failures per million hours. The inverse of the failure rate is the MTTF (exponential failure rate assumed). The number below each block is the reliability calculated using Equation (2.13) with *t* = 10 million hours.

2.8.6.1.1 Series configuration—Weakest link

Components A and B in Figure 2-5 are said to be in series, which means all must operate for the system to operate. Since the system can be no more reliable than the least reliable component, this configuration is often referred to as the *weakest link configuration*. An analogy would be a chain; the strength of the chain is determined by its weakest link.

2.8.6.1.2 Series calculation method 1

Since the components are in series, the system reliability can be found by adding together the failure rates of the components. The system failure rate is 0.001000 + 0.001500 = 0.002500. The reliability is shown in Equation (2.19):

$$R(t) = e^{-0.0025\times 10} = 0.9753 \tag{2.19}$$

2.8.6.1.3 Series calculation method 2

Alternatively, we could find the system reliability by multiplying the reliabilities of the two components as follows: 0.9900 × 0.9851 = 0.9753.

2.8.6.2 Reliability with redundancy

Now consider the RBD shown in Figure 2-6.

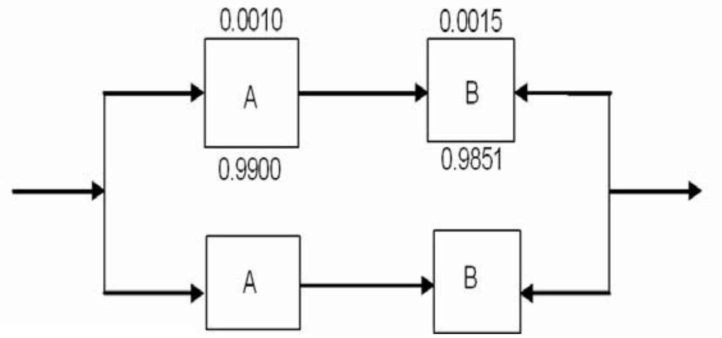

Figure 2-6—RBD of a system with redundant components

NOTE—The number above each block in Figure 2-6 is the failure rate in failures per million hours. The inverse of the failure rate is the MTTF (exponential failure rate assumed). The number below each block is the reliability.

The system represented by the block diagram in Figure 2-6 has the same components (A and B) used in Figure 2-5, but two of each component are used in a configuration referred to as *redundant* or *parallel*. Two paths of operation are possible. The paths are top A-B or bottom A-B. If either of two paths is intact, the system can operate. The reliability of the system is most easily calculated by finding the probability of failure ($1 - R(t)$) for each path, multiplying the probabilities of failure (which gives the probability of both paths failing), and then subtracting the result from 1. The reliability of each path was found in the previous example. Next, the probability of a path failing is found by subtracting its reliability from 1. Thus, the probability of either path failing is $1 - 0.9753 = 0.0247$. The probability that both paths will fail is $0.0247 \times 0.0247 = 0.0006$. Finally, the reliability of the system is $1 - 0.0006 = 0.9994$, a significant improvement over the series-configured system, which had a reliability of 0.9753.

2.8.6.3 N + X redundancy

System redundancy is not restricted to simply having twin systems. Where N is defined as the required piece of equipment to achieve an operational system, 2N would, in turn, imply that there is double the capacity, i.e., 1 of 2 are required to operate for system success. In some facilities, where there is a full 2N philosophy for redundancy, the facility will often have one additional piece of equipment on each side so that if one of the N pieces of equipment is down for maintenance, the facility still is 2N redundant. This would be the 2(N + 1) configuration.

With respect to availability, the following tables represent the availability of a system that requires 1000 kVA of power, assuming that each has an availability of 0.99.

Case 1: Use 1000 kVA generators → N = 1

Case 2: Use 500 kVA generators → N = 2

Number of generators	Redundancy	Requirement	Availability
1	N	1 of 1	0.99
2	N + 1	1 of 2	0.9999
3	N + 2	1 of 3	0.999999

Number of generators	Redundancy	Requirement	Availability
2	N	2 of 2	0.98
3	N + 1	2 of 3	0.9997
4	N + 2	2 of 4	0.999996

Case 3: Use 250 kVA generators → N = 4

Number of generators	Redundancy	Requirement	Availability
4	N	4 of 4	0.96
5	N + 1	4 of 5	0.9990
6	N + 2	4 of 6	0.99998

2.8.6.4 M of N calculations for reliability

Equation (2.20) can be used for calculating the reliability of an m of n system for any arbitrary m or n:

$$R(t) = \sum_{k=m}^{n} \frac{n!}{k!(n-k)!}(e^{-\lambda k})^{k}(1-e^{-\lambda k})^{(n-k)} \tag{2.20}$$

where

n is the total number of components
m is the required components

2.9 Methods of reliability and availability analysis

The intent of the tools in this subclause—and the entire chapter—is to perform availability analyses for systems. These tools, particularly those resulting from the exponential distribution are directly applicable to one family of analyses: analytical. The PDFs introduced in 2.8 can be used to their greatest potential in numerical analyses using Monte Carlo simulation.

2.9.1 Analytical methodologies

Analytical methods utilize logical algebraic formulas to arrive at a closed-form, exact, solution to a model of a system. Simple systems, as seen in 2.8.6.1, can be calculated with pencil and paper. That exercise grows linearly as the model grows linearly. Several techniques/algorithms streamline the process of calculating availability for large systems.

2.9.1.1 Cut-set

The cut-set method can be applied to systems with simple as well as complex configurations and is a very suitable technique for the reliability analysis of power distribution systems. A cut-set is a "set of components whose failure alone will cause system failure," and a minimal cut-set has no proper subset of components whose failure alone will cause system failure. The components of a minimal cut-set are in parallel since all of them must fail in order to cause system failure, and various minimal cut-sets are in series as any one minimal cut-set can cause system failure.

2.9.1.2 Network reduction

The network reduction method is useful for systems consisting of series and parallel subsystems. This method consists of successively reducing the series and parallel structures by equivalent components. Knowledge of the series and parallel reduction formulas is essential for the application of this technique.

2.9.1.3 GO algorithm

The GO algorithm, a success-oriented system analysis technique, was originally developed for defense industry applications in the early 1960s. The capability of the GO methodology was drastically improved under the sponsorship of the Electric Power Research Institute (EPRI) with the development of additional analytical techniques (i.e., system interactions, system dependencies, and man-machine interactions) and improved computer software reliability. The popularity of the GO method can be linked to basic characteristics that fault trees do not possess, including: 1) hardware is modeled in a manner more or less the same way as in the system drawings, 2) model modifications can be easily introduced to reflect configuration changes, and 3) the modeling capability is extremely flexible. GO's success-oriented technique analyzes system performance through straightforward inductive logic. The GO representation of a system, or GO model, can often be constructed directly from engineering drawings, which makes GO a valuable tool for many applications, since it is relatively easy to build and review models.

A system model is first constructed within the GO methodology using a top-down (forward-looking) approach to identify the functions required for successful operation following normal process flow or operational sequences. Secondly, in the GO methodology each of the systems that provide the functionality is modeled to the required level of detail. The level of detail may be at the system, subsystem, or component level depending upon the type of information required and the plant specific information available. The GO models determine all system-response modes: successes, failures, prematures, etc.

GO models consist of arrangements of GO operator symbols and represent the engineering functions of components, subsystems, and systems. The models are generally constructed from engineering (one-line) drawings by replacing engineering elements (valves, motors, switches, etc.) with one or more GO symbols that are interrelated to represent system functions, logic, and operational sequences. The GO software uses the GO model to quantify system performance. The method evaluates system reliability and availability, identifies fault sets, ranks the relative importance of the constituent elements, and places confidence bounds on the probabilities of occurrence of system events reflecting the effects of data uncertainties.

Some key features of the GO method are as follows:

a) Models follow the normal process flow
b) Most model elements have one-to-one correspondence with system elements
c) Models accommodate component and system interactions and dependencies
d) Models are compact and easy to validate
e) Outputs represent all system success and failure states
f) Models can be easily altered and updated
g) Fault sets can be generated without altering the basic model
h) System operational aspects can be incorporated
i) Numerical errors due to pruning are known and can be controlled

The GO procedure uses a set of 17 standard logical operators to represent the logic operation, interaction, and combination of physical equipment and human actions. For example, a type 1 operator represents the logical operation of equipment that either performs, or fails to perform, its function given a proper input or stimulus. The type 2 operator performs the logical OR gate operation where a successful response is generated if any of several inputs is proper, etc. The random variables of the GO methodology include operator inputs called *stimuli* ($S1$, $S2$,…, Sn) and outputs referred to as *responses* ($R1$, $R2$,…, Rn). An operator, which represents equipment responses or human actions and which may itself have associated performance probabilities, processes the input random variable in a prescribed and well-defined way to generate the output random variables. These random variables are given the electrical term *signals* in the GO models.

2.9.2 Numerical methods

2.9.2.1 State space

The state space methodology is founded on a more general mathematical concept called *Markov chains.* Markov chains are a modeling technique that describes a system by the possible states in which it can possess (i.e., state space). For our purpose, a system essentially resides in two distinct states: up or down. The probability of transitioning from one state to the other in a given time period is the critical reliability metric that we are after. Figure 2-7 shows this simple Markov model.

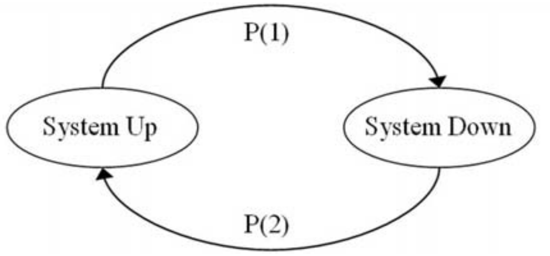

Figure 2-7—Simple Markov model

where

P(1) is the probability of the system going down in time *t*
P(2) probability of the system coming up in time *t*

However, the true goal of availability analysis is to determine the probability of being in the "up" state—or the time spent in the up state for a given time *t*. To show this, consider the simpler scenario including only a system with backup generation. Given loss of utility power, the generators will either start automatically, or if that functionality fails, the generators can be started manually. In those starting phases, the system is "down." Once started, the system is up. The system will then switch to utility power once available. The system could be down during that switching.

Figure 2-8 shows the associated Markov model for this system. Between each of the possible states are state transitional probabilities that must be known. The solution to the model will be the time spent in the up states vs. the down states.

Solving Markov models is simple only for very simple models, by solving a set of linear equations. The complexity solving these models grows exponentially as the sizes of the models grow linearly. Solutions can be found by using complex numerical analysis methods involving linear algebraic matrix operations, etc. Markov models can also be solved by Monte Carlo techniques described as follows.

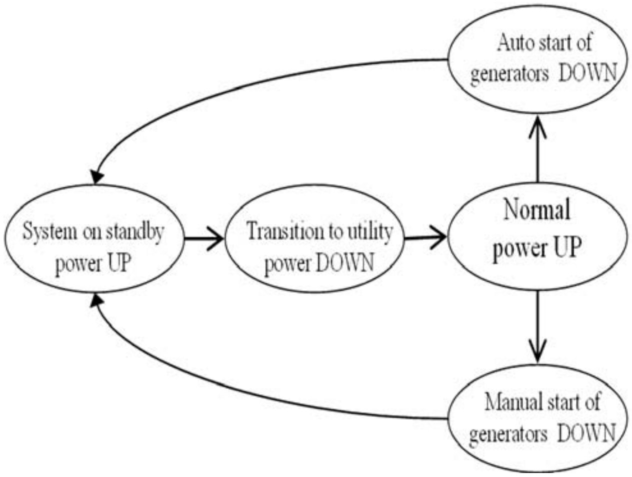

Figure 2-8—Less simple Markov model

2.9.2.2 Monte Carlo simulation

Monte Carlo simulation is the most versatile modeling methodology available. The methodology can be implemented in many forms from simple models in a spreadsheet environment to complex models that are "handcrafted" in a programming language of choice. There are also a variety of simulation software packages that provide drag-and-drop environments that can automate the creation of simulated models for the casual analyst.

2.9.2.3 Simulation basics

The Monte Carlo simulator operates on an iterative process where each "iteration" represents a description of what the system could experience through a set mission life. For instance, if we consider the past experience of a system, including what really failed, that experience was only one of infinite possible outcomes that depended on the failure characteristics of that system.

Thus, Monte Carlo simulation looks forward by considering possible scenarios that could occur in the future—and those scenarios, with their associated likelihoods, is dependent on the failure characteristics applied to the system components. For each iteration, failure times, and the associated repair attributes, are picked for each component in the system. The simulation will then implement the logical relationships of the system to determine the following:

a) If a failure has occurred in the system prior to the defined mission life.

b) If a failed component(s) takes the system down, what is the duration of downtime.

With these items determined, the availability for the system in that particular iteration can be calculated. Then, as this single iteration is repeated, an average is tabulated of uptime vs. downtime, and duration of downtimes. The average of all the iterations yields expected system availability.

2.10 Performing reliability and availability analyses

The results of availability analyses are extremely sensitive to factors such as underlying assumptions, techniques for calculating availability, and the data used to support the analysis. No results of an analysis should be distributed—let alone trusted—without documentation supporting those attributes. Subtle differences in those attributes can produce drastically different results, results that might be used to drive design decision making. It is the ultimate responsibility of the analyst to be aware of those sensitivities and perform and present analyses with integrity.

2.10.1 Modeling limitations

Cut-set, state space, network reduction, and Boolean algebra are techniques that lend themselves to the casual reliability engineer to analyze small systems, primarily because they can all be accomplished with common desktop PC tools such as spreadsheets, etc. A series of studies recently performed on the *Gold Book Standard Network* have shown that, provided that the assumptions are held equal, each technique produces similar results. The first four techniques however become impractical under certain conditions.

2.10.1.1 Network size

As larger systems are modeled, the sheer size of the analysis becomes burdensome for the analyst. Furthermore, "what-if" sensitivity analyses also become impractical.

2.10.1.2 Smarter distributions

Data collection efforts have expanded the analysts' tools beyond the classical MTBF analysis. Failure distributions such as the normal, lognormal, Weibull, etc., are being fitted to common failure modes of many critical components in power distribution networks.

2.10.1.3 Modeling hurdles

There are several system attributes that are challenging to model. UPS battery life, for instance, had historically been assumed to be limitless in many analyses, whereas their contribution to power availability is not. Furthermore, Data has shown that standby equipment has differing distributions from their primary counterparts. Thirdly, spare parts availability, human factors, etc., are difficult to capture with the classical approaches to availability analysis.

2.10.2 Modeling solutions

The typical engineer can perform "back of the envelope" analyses easily. Results from these analyses are only as good as the assumed ground rules and the data used. Experience has shown that analysts who wish to perform availability studies often and consistently should choose a software package to aid in this effort. Packages exist that perform analyses via most of the described methodologies. Once a package is selected, the user should become familiar with the package behavior, the analytical or numerical methodology used, and the underlying limitations of that package.

Chapter 3 uses the minimal cut-set methodology for its examples. Furthermore, the chapter provides a comparison of results from various methodologies.

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[3] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

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[5] MIL publications are available from Customer Service, Defense Printing Service, 700 Robbins Ave., Bldg. 4D, Philadelphia, PA 19111-5094.

Chapter 3
Planning and design

3.1 Introduction

Fundamentals necessary for a quantitative reliability evaluation in electric power systems involved in planning and designing include definitions of basic terms, discussions of useful measures of system reliability and the basic data needed to compute these indexes, and a description and references of procedures for system reliability analysis including computation of quantitative reliability indexes. An important aspect of power system design involves consideration of the service reliability requirements of loads that are to be supplied and the service reliability that will be provided by any proposed system. System reliability assessment and evaluation methods based on probability theory allow the reliability of a proposed system to be assessed quantitatively. Such methods permit consistent, defensible, and unbiased assessments of system reliability that are not otherwise possible.

The quantitative reliability evaluation methods permit reliability indexes for any electric power system to be computed from knowledge of the reliability performance of the constituent components of the system. Thus, alternative system designs can be studied to evaluate the impact on service reliability and cost of changes in component reliability, system configuration, protection and switching scheme, or system operating policy including maintenance practice.

In this chapter, a description is given of how to make quantitative reliability and availability predictions for proposed new and existing configurations of industrial power distribution systems. A discussion is presented on the important factors that must be considered in the reliability analysis of industrial and commercial power systems. Some of these factors are: reliability indexes, reliability data (e.g., component failure rates, repair and replacement times, switching times), definition of interruptions, and reliability equations. Seven examples of industrial system configurations (e.g., a simple radial system, a primary-selective system, secondary-selective system) are worked out in detail showing how the failure of individual components affect the overall reliability levels at a point of use within an industrial facility. The following chapters present a detailed discussion of other factors that impact the planning and design of industrial and commercial power systems:

Chapter 4: Evaluating and improving the reliability of an existing electrical system
Chapter 5: Preventative maintenance
Chapter 6: Emergency and standby power
Chapter 7: Voltage sag analysis
Chapter 8: 7 × 24 continuous power facilities
Chapter 9: Reliability and maintainability verification
Chapter 10: Summary of equipment reliability data
Chapter 11: Data collection

Recent surveys on the cost of power interruptions to industrial, commercial, and institutional facilities will be summarized and presented in this chapter. The estimated cost of power interruptions to an individual facility can be factored into the decision as to which type of power distribution system to use. This approach could be used to assist in cost-reliability trade-off decisions in the design of the power distribution system.

3.2 Fundamentals of power system reliability evaluation

3.2.1 System reliability indexes

The basic system reliability indexes (IEEE Std 493™-1997)[1] that have proven most useful and meaningful in power distribution system design are as follows:

a) Frequency of load point interruptions
b) Expected duration of load point interruption events

These indexes can be readily computed using the methods that will be described and referenced in this chapter. The two basic indexes (interruption frequency and expected interruption duration) can be used to compute the following indexes that are also useful in the planning and design of industrial and commercial power systems.

1) Total expected (average) interruption time per year (or other time period)
2) System availability or unavailability as measured at the load supply point in question
3) Expected demand, but unsupplied, energy per year

It should be noted here that the disruptive effect of power interruptions is often non linearly related to the duration of the interruption. Thus, it is often desirable to compute not only an overall interruption frequency but also frequencies of interruptions categorized by the appropriate durations.

3.2.2 What is an interruption?

Evaluation of reliability begins with the establishment of an interruption definition. Such a definition specifies the magnitude of the voltage sag and the minimum duration of such a reduced-voltage period that result in a loss of production or other function for the plant, process, or building in question. Frequently, interruption definitions are given only in terms of a minimum duration and assume that the voltage is zero during that period. A detailed discussion of critical service loss duration for industrial and commercial plants and plant restart times is presented in Chapter 7.

3.2.3 Service interruption definition

The first step in any electric power system reliability study should be a careful assessment of the power supply quality and continuity required by the loads that are to be served. This assessment should be summarized and expressed in a service interruption definition that

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[1] Information on references can be found in 3.6.

can be used in the succeeding steps of the reliability evaluation procedure. The interruption definition specifies, in general, the reduced voltage level (voltage dip or sag) together with the minimum duration of such a reduced voltage period that results in substantial degradation or complete loss of function of the load or process being served. Frequently, reliability studies are conducted on a continuity basis in which case interruption definitions reduce to a minimum duration specification with voltage assumed to be zero during the interruption, which will be assumed in the reliability analysis presented in this chapter. A method for calculating the magnitude of voltage sags is given in Chapter 7. Sags can be caused by faults elsewhere on the power system.

3.2.4 Data needed for system reliability evaluations

The data needed for quantitative evaluations of system reliability depend to some extent on the nature of the system being studied and the detail of the study. In general, however, data on the performance of individual components together with the times required to perform repair and/or replacement actions and the times for various switching operations are summarized as follows:

a) Failure rates (forced outage rates) associated with different modes of component failure
b) Expected (average) time to repair or replace failed component
c) Scheduled (maintenance) outage rate of component
d) Expected (average) duration of a scheduled outage event

The needed manual or automatic switching time data include the following:

1) Expected times to open and close a circuit breaker
2) Expected times to open and close a disconnect or transfer switch
3) Expected time to replace a fuse link
4) Expected times to perform such emergency operations

Switching times should be estimated for the system being studied based on experience, engineering judgment, and anticipated operating practice.

If possible, component data should be based on the historical performance of components in the same environment as those in the proposed system being studied. The reliability surveys conducted by the Power Systems Reliability Subcommittee and the U.S. Army Corps of Engineers Power Reliability Enhancement Program (PREP) (reliability data contained in Chapter 10) provide a source of component data when such site-specific data are not available. Chapter 11 provides a framework for collecting reliability data.

3.2.5 Method for system reliability evaluation

There are many computer reliability methodologies available today for analyzing complex industrial and commercial power system configurations. The methods for system reliability evaluation have evolved over a number of years (Dickenson et al. [B6], Feduccia and Klion [B9], Patton et al. [B27], Wells [B34], and Love [B25]).[2] The minimal cut-set method will be used in the analysis of various electric power distribution systems. The method is systematic and straightforward and lends itself to either manual or computer computation. An important feature of the method is that system weak points can be readily identified, both numerically and non-numerically, thereby focusing design attention on those sections or components of the system that contribute most to service unreliability.

One of the main benefits of a reliability and availability analysis is that a disciplined look is taken at the alternative choices in the design of the power distribution system. By using published reliability data collected by a technical society from industrial plants, the best possible attempt is made to use historical experience to aid in the design of the new system.

3.3 Examples of reliability and availability analysis of common low-voltage industrial power distribution systems

Seven examples of common low-voltage industrial power distribution systems are analyzed in this subclause:

a) *Example 1*—Simple radial
b) *Example 2*—Primary selective to 13.8 kV utility supply
c) *Example 3*—Primary selective to load side of 13.8 kV circuit breaker
d) *Example 4*—Primary selective to primary of transformer
e) *Example 5*—Secondary selective
f) *Example 6*—Simple radial with a spare transformer
g) *Example 7*—Simple radial system with cogeneration

The common low-voltage industrial power distribution systems presented in this chapter are used only to illustrate the reliability methodologies and are not actual distribution systems.

Only permanent forced outages of the electrical equipment are considered in the seven examples. It is assumed that scheduled maintenance will be performed at times when 480 V power output is not needed. The frequency of scheduled outages and the average duration can be estimated, and if necessary, these can be added to the forced outages given in the seven examples.

When making a reliability study, it is necessary to define what is a failure of the supply to the 480 V point of utilization. Some of the failure definitions that are often used are as follows:

1) Complete loss of incoming power for more than 1 cycle
2) Complete loss of incoming power for more than 10 cycles
3) **Complete loss of incoming power for more than 5 s**
4) Complete loss of incoming power for more than 2 m

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[2] The numbers in brackets correspond to those of the bibliography in 3.7.

Definition 3) will be used in the seven examples given. This definition of failure can have an effect in determining the necessary speed of automatic transfer equipment that is used in primary-selective or secondary-selective systems. In some cases when making reliability studies, it might be necessary to further define what is a complete loss of incoming power, for example, voltage drops below 70%.

3.3.1 Definition of terminology used in examples

The units that are being used for "failure rate" and "average downtime per failure" are defined as follows:

λ = Failure rate (failures per year)

r = Average downtime per failure (hours per failure) = average time to repair or replace a piece of equipment after a failure. In some cases this is the time to switch to an alternate circuit when one is available.

3.3.2 Procedure for reliability and availability analysis

The quantitative reliability indexes that are used in the seven examples are the failure rate and the forced hours downtime per year. These are calculated at the 480 V point of use in each example. The failure rate λ is a measure of unreliability. The product λr, (failure rate × average downtime per failure) is equal to the forced hours downtime per year and can be considered a measure of forced unavailability since a scale factor of 8760 converts one quantity into the other. The average downtime per failure r could be called *restorability.*

The necessary formulas for calculating the reliability indexes are given in Equation (3.1), Equation (3.2), Equation (3.3), Equation (3.4), Equation (3.5), and Equation (3.6). A sample using these formulas is shown in Figure 3-1 for two components numbered "1" and "2" connected in series and two components "3" and "4" connected in parallel. In these samples scheduled outages are assumed to be zero and the units for λ and r are, respectively, failures per year and hours downtime per failure. The equations in Figure 3-1 and Figure 3-2 assume the following:

a) The component failure rate is constant with age.
b) The outage time after a failure has an exponential distribution.
c) Each failure event is independent of any other failure event.
d) The component "up" times are much larger than "down" times: $\lambda_i r_i / 8760 < 0.01$.

The definitions of the nomenclature used in Figure 3-1 and Figure 3-2 are:

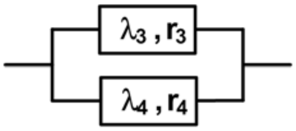
f = Frequency of failures
λ_i = Failure rate for the ith component expressed in failures per hour
r_i = Average hours of downtime per failure for the ith component
s = Series
p = Parallel

$$f_s = \lambda_1 + \lambda_2 \tag{3.1}$$

$$f_s r_s = \lambda_1 r_1 + \lambda_2 r_2 \tag{3.2}$$

$$r_s \cong \frac{\lambda_1 r_1 + \lambda_2 r_2}{\lambda_1 + \lambda_2} \tag{3.3}$$

Figure 3-1—Repairable components in series (both must work for success)



$$f_p = \frac{\lambda_3 \lambda_4 (r_3 + r_4)}{8760} \tag{3.4}$$

$$f_p r_p = \frac{\lambda_3 r_3 \lambda_4 r_4}{8760} \tag{3.5}$$

$$r_p = \frac{r_3 r_4}{r_3 + r_4} \tag{3.6}$$

Figure 3-2—Repairable components in parallel (one or both must work for success)

The formulas shown in Figure 3-2 are approximate and should only be used when both ($\lambda_3 r_3$ / 8760) and ($\lambda_4 r_4$ / 8760) are less than 0.01.

3.3.3 Reliability of electric utility power supplies to industrial plants

The failure rate and average downtime per failure data for the electric utility power supplies are given in Table 3-1. This includes both single-circuit and double-circuit reliability data. The two power sources in a double-circuit utility supply are not completely independent, and the reliability and availability analysis must take this into consideration.

A failure of an in-plant component causes a forced outage of a component; that is, the component is unable to perform its intended function until it is repaired or replaced. The terms *failure* and *forced outage* are often used synonymously.

Table 3-1—IEEE survey of reliability of electric utility power supplies to industrial plants[a]

Number of circuits (all voltages)	λ	r	λr
Single circuit	1.956	1.32	2.582
Double circuit Loss of both circuits[b]	0.312	0.52	0.1622
Double circuit—Calculated value for loss of source 1 (while source 2 is OK)	1.644	0.15[c]	0.2466
Calculated two utility power sources at 13.8 kV that are assumed to be completely independent	0.00115[d]	0.66[d]	0.00076

[a] See IEEE Committee Report [B17].
[b] Data for double circuits that had all circuit breakers closed.
[c] Manual switchover time of 9 min to source 2.
[d] Calculated using single-circuit utility power supply data and the equations for parallel reliability shown in Figure 3-5.

In addition to the reliability data for electrical equipment presented in Chapter 10, there are some “failure modes” of circuit breakers that require backup protective equipment to operate; for example, “failed to trip” or “failed to interrupt.” Both of these failure modes would require that a circuit breaker farther up the line be opened, and this would result in a larger part of the power distribution system being disconnected. Reliability data on the failure modes of circuit breakers are shown in Table 3-2. These data are used for the 480 V circuit breakers in all seven examples discussed later in this subclause. It will be assumed that the “flashed over while open” failure mode for circuit breakers and disconnect switches has a failure rate of 0.0.

Table 3-2—Failure modes of circuit breakers—Percentage of total failures (Tf) in each failure mode

Percentage of Tf (all voltages)	Failure characteristics
9	Backup protective equipment required (failed while opening)
	Other circuit breaker failures
7	Damaged while successfully opening
32	Failed while in service (not while opening or closing)
5	Failed to close when it should

Table 3-2—Failure modes of circuit breakers—Percentage of total failures (Tf) in each failure mode

Percentage of Tf (all voltages)	Failure characteristics
2	Damaged while closing
42	Opened when it should not
1	Failed during testing or maintenance
1	Damage discovered during testing or maintenance
1	Other
100	Total percentage

3.3.4 Example 1: Reliability and availability analysis of a simple radial system

3.3.4.1 Description

A simple radial system is shown in Figure 3-3. Power is received at 13.8 kV from the electric utility. It goes a very short section of cable through the primary metering, protection, and control system and then through a 13.8 kV circuit breaker inside the industrial plant. The circuit continues through a 128.44 m cable in underground conduit, and a 91.44 m cable is spliced into the 182.88 m cable. The end of the 128.44 m cable is connected to an enclosed disconnect switch. A short piece of cable connects the enclosed disconnect switch to a transformer, which reduces the voltage to 480 V. The circuit continues through a 480 V main circuit breaker, then a 480 V switchgear bus-bar and then to a second 480 V circuit breaker, 91.44 m of cable in aboveground conduit, to the point where the power is used in the industrial plant.

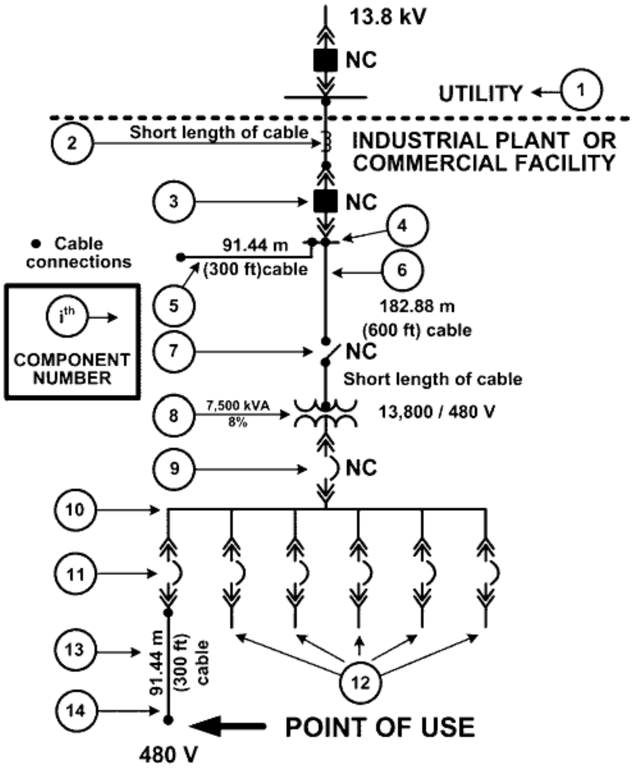


Figure 3-3—Simple radial system—Example 1

3.3.4.2 Results

The results from the reliability and availability calculations for the simple radial system shown in Figure 3-3 are given in Table 3-3. The failure rate and the forced hours downtime per year are calculated at the 480 V point of use.

The relative ranking of how each component contributes to the failure rate is of considerable interest. This is tabulated in Table 3-4.

Table 3-3—Simple radial system—Failure rate and forced hours downtime per year at 480 V point of use (Example 1)

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.956000	2.582000	0.999705338
2	Primary protection and control system	0.000600	0.003000	0.999999658
3	13.8 kV metal-clad circuit breaker	0.001850	0.000925	0.999999894
4	13.8 kV switchgear bus—insulated	0.004100	0.153053	0.999982529
5	Cable (13.8 kV) 274.32 m (900 ft), conduit playground	0.002124	0.033347	0.999996193
6	Cable terminations (8) at 13.8 kV	0.002960	0.002220	0.999999747
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
8	Transformer	0.010800	1.430244	0.999836757
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**1.990940**	**4.279332**	**0.999511730**

The data for hours of downtime per failure are based upon *repair failed unit.*

Table 3-4—Simple radial system relative ranking of failure rates

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.956000	2.582000	0.999705338
8	Transformer	0.010800	1.430244	0.999836757
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
4	13.8 kV switchgear bus—insulated	0.004100	0.153053	0.999982529
6	Cable terminations (8) at 13.8 kV	0.002960	0.002220	0.999999747
5	Cable (13.8 kV), 274.32 m (900 ft), conduit playground	0.002124	0.033347	0.999996193
3	13.8 kV metal-clad circuit breaker	0.001850	0.000925	0.999999894
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
2	Primary protection control system	0.000600	0.003000	0.999999658
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V); 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981

The relative ranking of how each component contributes to the forced hours downtime per year is also of considerable interest. This is given in Table 3-5.

It might be expected that the power distribution system would be shut down once every 2 years for scheduled maintenance for a period of 24 h. These shutdowns would be in addition to the outage data given in Table 3-3 and Table 3-4.

Table 3-5—Simple radial system relative ranking of forced hours of downtime per year

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.956000	2.582000	0.999705338
8	Transformer	0.010800	1.430244	0.999836757
4	Switchgear bus—insulated	0.004100	0.153053	0.999982529
10	Switchgear bus—bare	0.009490	0.069182	0.999992103
5	Cable (13.8 kV), 274.32 m (900 ft) conduit playground	0.002124	0.033347	0.999996193
2	480 V metal-clad circuit breakers (5) (failed while opening)	0.000956	0.003823	0.999999564
6	Primary protection and control system	0.000600	0.003000	0.999999658
7	Cable connections (8) at 13.8 kV	0.002960	0.002220	0.999999747
12	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
3	13.8 kV metal-clad circuit breaker	0.001850	0.000925	0.999999894
14	Cable connections (2) at 480 V	0.000740	0.000555	0.999999937
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981

3.3.4.3 Conclusions

The electric utility supply is the largest contributor to both the failure rate and the forced hours downtime per year at the 480 V point of use. It is very important to obtain accurate electric utility supply reliability data to a particular facility. A significant improvement can be made in both the failure rate and the forced hours downtime per year by having two sources of power at 13.8 kV from the electric utility. The improvements that can be obtained are shown in Examples 2, 3, and 4 using a “primary-selective system” and in Example 5 using a “secondary-selective system.”

The transformer is the second largest contributor to forced -hours downtime per year. The transformer has a very low failure rate, but the long outage time of 132.43 h after a failure results in a large forced hours downtime per year.

The long outage times after a failure for the transformer are all based upon “repair failed unit.” These outage times after a failure can be reduced significantly if the “replace with spare” times are used instead of repair failed unit. This is done in Example 6, using a simple radial system with spares.

3.3.5 Example 2: Reliability and availability analysis of primary-selective system to 13.8 kV utility supply

3.3.5.1 Description

The primary-selective system to 13.8 kV utility supply is shown in Figure 3-4. It is a simple radial system with the addition of a second 13.8 kV power source from the electric utility; the second power source is normally disconnected. In the event that there is a failure in the first 13.8 kV utility power source, then the second 13.8 kV utility power source is switched on to replace the failed power source. Assume that the two utility power sources are synchronized.

The following examples will be analyzed:

Example 2a—Assume a 9 min “manual switchover time” to utility power source No. 2 after a failure of source No. 1. The results from the reliability and availability calculations for the primary-selective system to 13.8 kV supply system shown in Figure 3-4 are given in Table 3-6. The data for hours of downtime per failure are based upon *repair failed unit.*

Example 2b—Assume an “automatic switchover time” of less than 5 s after a failure is assumed (loss of 480 V power for less than 5 s is not counted as a failure). The results from the reliability and availability calculations for the primary-selective system to 13.8 kV supply system shown in Figure 3-4 are given in Table 3-7. The data for hours of downtime per failure are based upon *repair failed unit.*

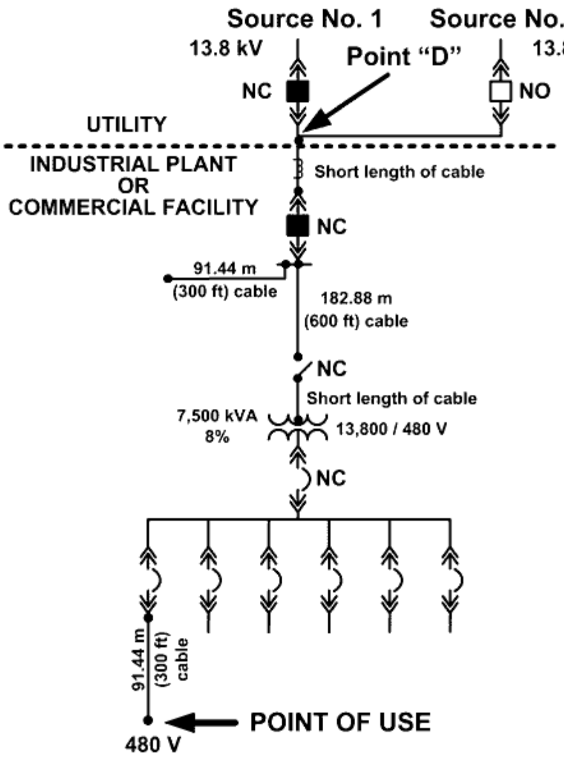


Figure 3-4—Primary-selective system to 13.8 kV utility supply—Example 2

Table 3-6—Primary-selective system to 13.8 kV utility supply—Failure rate and forced hours downtime per year at 480 V point of use (Example 2a), assuming a 9 min manual switchover time to utility power source No. 2

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.644000		
2	Primary protection and control system	0.000600		
3	13.8 kV metal-clad circuit breaker	0.001850		
		1.646450	0.246968	0.999971808
	Loss of both 13.8 kV power sources simultaneously	0.312000	0.162240	0.999981480
	Total to point D	1.958450	0.409208	
4	13.8 kV switchgear bus—insulated	0.004100	0.153053	0.999982529
5	Cable (13.8 kV), 274.32 m (900 ft), conduit playground	0.002124	0.033347	0.999996193
6	Cable terminations (8) at 13.8 kV	0.002960	0.002220	0.999999747
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
8	Transformer	0.010800	1.430244	0.999836757
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**1.990940**	**2.102614**	**0.999760033**

Table 3-7—Primary-selective system to 13.8 kV utility supply— Failure rate and forced hours downtime per year at 480 V point of use (Example 2b), assuming a 5 s automatic transfer to utility power source No. 2

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.644000		
2	Primary protection and control system	0.000600		
3	13.8 kV metal-clad circuit breaker	0.001850		
		0.0	0.0	1.000000000
	Loss of both 13.8 kV power sources simultaneously	0.312000	0.162240	0.999981480
Total to point D		0.312000	0.162240	
4	13.8 kV switchgear bus—insulated	0.004100	0.153053	0.999982529
5	Cable (13.8 kV), 274.32 m (900 ft), conduit playground	0.002124	0.033347	0.999996193
6	Cable terminations (8) at 13.8 kV	0.002960	0.002220	0.999999747
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
8	Transformer	0.010800	1.430244	0.999836757
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**0.344490**	**1.855647**	**0.999788213**

3.3.5.2 Results

Example 2a—If the time to switch to a second utility power source takes 9 min after a failure of the first source, then there would be a power supply outage of 9 min duration. Using the data from Table 3-8,[3] for double-circuit utility supplies, this would occur 1.644 times per year. This in addition to losing both power sources simultaneously 0.312 times per year for an average outage time of 0.52 h. If these utility supply data are added together and substituted into Table 3-3 on the simple radial system, it would result in reducing the forced hours downtime per year at the 480 V point of use from 4.279332 to 2.102614. The failure rate would stay the same at 1.990940 failures per year. These results are given in Table 3-8.

Table 3-8—Simple radial system and primary-selective system to 13.8 kV utility supply reliability and availability comparison of power at 480 V point of use

Distribution system	λ	λr	Ai
Example 1 Simple radial system	1.990940	4.279332	0.999511730
Example 2a Primary-selective system to 13.8 kV utility supply (with 9 min switchover after a supply failure)	1.990940	2.102614	0.999760033
Example 2b Primary-selective system to 13.8 kV utility supply (with switchover in less than 5 s after a supply failure) (see Note)	0.344490	1.855647	0.999788213
NOTE—Loss of 480 V power for less than 5 s is not counted as a failure.			

Example 2b—If the time to switch to a second utility power source takes less than 5 s after a failure of the first source, then there would be no failure of the electric utility power supply. The only time a failure of the utility power source would occur is when both sources fail simultaneously. It will be assumed that the data shown in Table 3-8 are applicable for loss of both power supply circuits simultaneously. This is 0.312 failures per year with an average outage time of 0.52 h. If these values of utility supply data are substituted into Table 3-3, it would result in reducing the forced hours downtime per year from 4.279332 to 1.855647 h per year at the 480 V point of use; the failure rate would be reduced from 1.990940 to 0.344490 failures per year. These results are also given in Table 3-8.

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[3] Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement the standard.

3.3.5.3 Conclusions

The use of primary-selective to the 13.8 kV utility supply with 9 min manual switchover time reduces the forced hours downtime per year at the 480 V point of use by about 50%, but the failure rate is the same as for a simple radial system.

The use of automatic transfer equipment that could sense a failure of one 13.8 kV utility supply and switchover to the second supply in less than 5 s would give a 6 to 1 improvement in the failure rate at the 480 V point of use (a loss of 480 V power for less than 5 s is not counted as a failure).

3.3.6 Example 3: Primary-selective system to load side of 13.8 kV circuit breaker

3.3.6.1 Description

Figure 3-5 shows a one-line diagram of the power distribution system for primary-selective to load side of 13.8 kV circuit breaker. What are the failure rate and the forced hours downtime per year at the 480 V point of use?

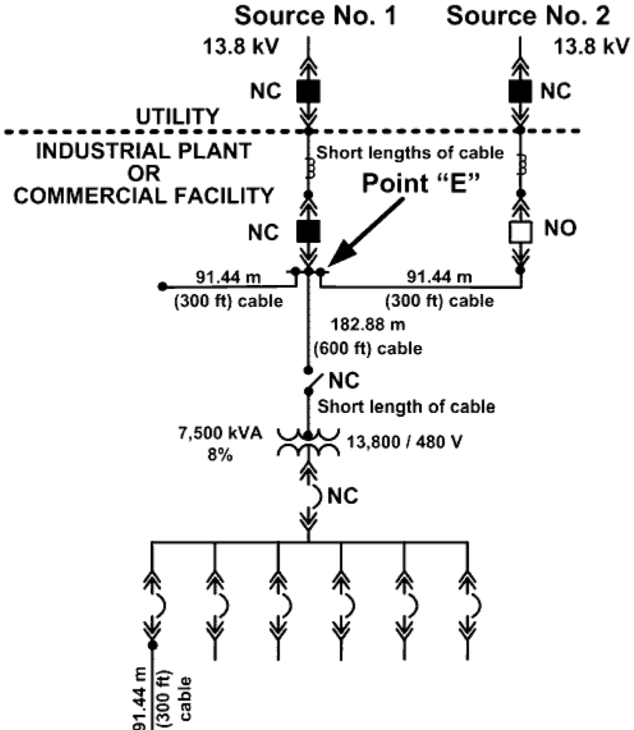

Figure 3-5—Primary-selective system to the load side of 13.8 kV circuit breaker—Example 3

The following examples will be analyzed:

Example 3a—Assume 9 min manual switchover time.

Example 3b—Assume automatic switchover can be accomplished in less than 5 s after a failure (loss of 480 V power for less than 5 s is not counted as a failure).

3.3.6.2 Results

The results from the reliability and availability calculations for examples 3a and 3b are given in Table 3-9 and Table 3-10.

Table 3-9—Primary-selective system to load side of 13.8 kV circuit breaker—Failure rate and forced hours downtime per year at 480 V point of use (Example 3a), assuming a 9 min manual switchover time to utility power source No. 2

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.644000		
2	Primary protection and control system	0.000600		
3	13.8 kV metal-clad circuit breaker	0.001850		
	Total through 13.8 kV circuit breaker with 9 min switchover after a failure of source 1 (and source 2 is okay)	1.646450	0.246968	0.999971808
	Loss of both 13.8 kV power sources simultaneously	0.312000	0.162240	0.999981480
4	13.8 kV switchgear bus—insulated	0.004100	0.153053	0.999982529
Total to point E		1.962550	0.562261	
5	Cable (13.8 kV), 365.76 m (1200 ft), conduit belowground	0.002832	0.044462	0.999994924
6	Cable terminations (10) at 13.8 kV	0.003700	0.002775	0.999999683
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
8	Transformer	0.010800	1.430244	0.999836757
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103

Table 3-9—Primary-selective system to load side of 13.8 kV circuit breaker—Failure rate and forced hours downtime per year at 480 V point of use (Example 3a), assuming a 9 min manual switchover time to utility power source No. 2 *(continued)*

Component number	Component	λ	λr	Ai
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**1.992388**	**2.114285**	**0.999758702**

Table 3-10—Primary-selective system to load side of 13.8 kV circuit breaker—Failure rate and forced hours downtime per year at 480 V point of use (Example 3b), assuming a 5 s automatic transfer to utility power source No. 2

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility			
2	Primary protection and control system			
3	13.8 kV metal-clad circuit breaker			
	Total through 13.8 kV circuit breaker with 9 s switchover after a failure of source 1 (and source 2 is okay)	0.0	0.0	1.000000000
	Loss of both 13.8 kV power sources simultaneously	0.312000	0.162240	0.999981480
4	13.8 kV Switchgear bus-insulated	0.004100	0.153053	0.999982529
Total to point E		0.316100	0.315293	0.999964009
5	Cable (13.8 kV), 365.76 m (1200 ft) conduit playground	0.002832	0.044462	0.999994924

Table 3-10—Primary-selective system to load side of 13.8 kV circuit breaker—Failure rate and forced hours downtime per year at 480 V point of use (Example 3b), assuming a 5 s automatic transfer to utility power source No. 2 *(continued)*

Component number	Component	λ	λr	Ai
6	Cable terminations (10) at 13.8 kV	0.003700	0.002775	0.999999683
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
8	Transformer	0.010800	1.430244	0.999836757
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**0.345938**	**1.867318**	**0.999786881**

3.3.6.3 Conclusions

The forced hours downtime per year at the 480 V point of use in Example 3 (primary-selective to load side of 13.8 kV circuit breaker) is about the same as in Example 2 (primary-selective to 13.8 kV utility supply). The failure rate is also about the same.

3.3.7 Example 4: Primary-selective system to primary of transformer

3.3.7.1 Description

Figure 3-6 shows a one-line diagram of the power distribution system for the primary-selective system to primary of transformer. What are the failure rate and the forced hours downtime per year at the 480 V point of use? Assume 1 h switchover time. The following examples will be analyzed:

Example 4a—Assume 9 min manual switchover time.

Example 4b—Assume automatic switchover can be accomplished in less than 5 s after a failure (loss of 480 V power for less than 5 s is not counted as a failure).

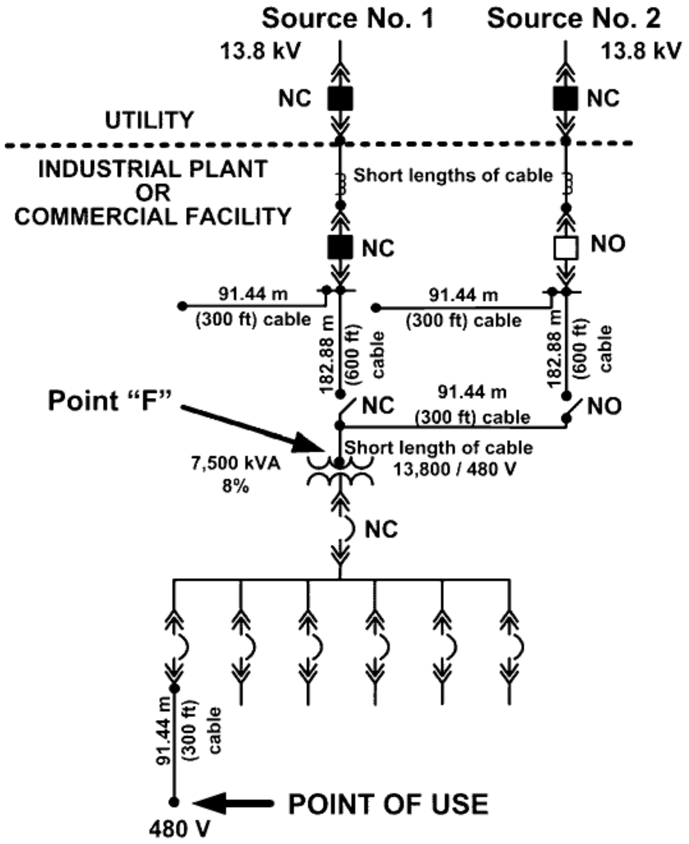

Figure 3-6—Primary-selective system to primary of transformer—Example 4

3.3.7.2 Results

The results from the reliability and availability calculations for examples 4a and 4b are given in Table 3-11 and Table 3-12.

Table 3-11—Primary-selective system to primary of transformer—Failure rate and forced hours downtime per year at 480 V point of use (Example 4a), assuming a 9 min manual switchover time to utility power source No. 2

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.644000		
2	Primary protection and control system	0.000600		
3	13.8 kV metal-clad circuit breaker	0.001850		
4	13.8 kV Switchgear bus—insulated	0.004100	0.153053	0.999982529
5	Cable (13.8 kV), 365.76 m (1200 ft), conduit belowground	0.002832	0.044462	0.999994924
6	Cable terminations (9) at 13.8 kV	0.003330	0.002498	0.999999715
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
	Total through 13.8 kV circuit breaker with 9 min switchover after a failure of source 1 (and source 2 is okay)	1.658452	0.248768	0.999971603
	Loss of both 13.8 kV power sources simultaneously	0.312000	0.162240	0.999981480
Total to point F		1.970452	0.411008	
8	Transformer	0.010800	1.430244	0.999836757
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**1.992018**	**1.914055**	**0.999781548**

Table 3-12—Primary-selective system to primary of transformer—Failure rate and forced hours downtime per year at 480 V point of use (Example 4b), assuming a 5 s automatic transfer to utility power source No. 2

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.644000		
2	Primary protection and control system	0.000600		
3	13.8 kV metal-clad circuit breaker	0.001850		
4	13.8 kV switchgear bus—insulated	0.004100	0.153053	0.999982529
5	Cable (13.8 kV); 365.76 m (1200 ft), conduit belowground	0.002832	0.044462	0.999994924
6	Cable terminations (9) at 13.8 kV	0.003330	0.002498	0.999999715
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
	Total through 13.8 kV circuit breaker with 5 s switchover after a failure of source 1 (and source 2 is okay)	0.0	0.0	1.000000000
	Loss of both 13.8 kV power sources simultaneously	0.312000	0.162240	0.999981480
Total to point F		0.312000	0.162240	
8	Transformer	0.010800	1.430244	0.999836757
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**0.333566**	**1.665287**	**0.999809935**

3.3.7.3 Conclusions

The forced hours downtime per year at the 480 V point of use in Example 4 (primary-selective system to primary of transformer) is about 55% lower than for the simple radial system shown in Example 1. The failure rate of the simple radial system was about six times larger than the primary-selective system in Example 5b with automatic switchover in less than 5 s and approximately the same as Example 5a with a manual switchover time of 9 min.

3.3.8 Example 5: Secondary-selective system

3.3.8.1 Description

Figure 3-7 shows a one-line diagram of the power distribution system for a secondary-selective system. What are the failure rate and forced hours of downtime per year at the 480 V point of use? The following examples will be analyzed:

Example 5a—Assume a 9 min manual switchover time.

Example 5b—Assume automatic switchover can be accomplished in less than 5 s after a failure (loss of 480 V power for less than 5 s is not counted as a failure).

3.3.8.2 Results

The results from the reliability and availability calculations at the 480 V point of use are given in Table 3-13 and Table 3-14.

3.3.8.3 Conclusions

The simple radial system in Example 1 had an average forced hours downtime per year that was about 18 times larger than the secondary-selective system in Example 5b with automatic throw-over in less than 5 s. The failure rate of the simple radial system was about six times larger than the secondary-selective system in Example 5b with automatic switchover in less than 5 s. These findings clearly demonstrate the impact of automatic transfer systems that do not disrupt the load during the transfer process.

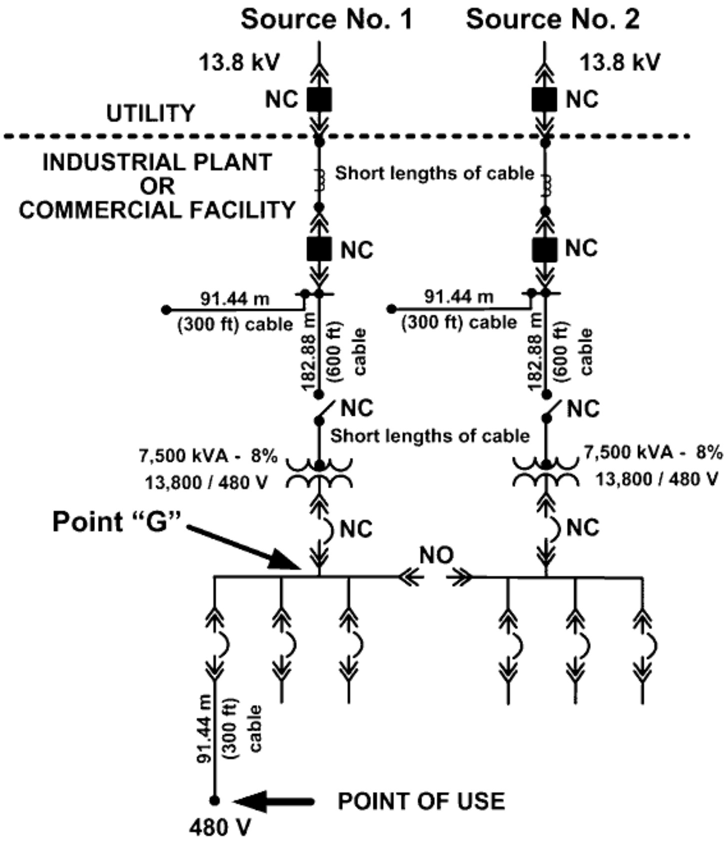

Figure 3-7—Secondary-selective system—Example 5

Table 3-13—Secondary-selective system—Failure rate and forced hours downtime per year at 480 V point of use (Example 5a), assuming a 9 min manual switchover time to utility power source No 2

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.644000		
2	Primary protection and control system	0.000600		
3	13.8 kV metal-clad circuit breaker	0.001850		
4	13.8 kV switchgear bus—insulated	0.004100		
5	Cable (13.8 kV), 365.76 m (1200 ft), conduit playground	0.002124		
6	Cable terminations (9) at 13.8 kV	0.002960		
7	Disconnect switch (enclosed)	0.001740		
8	Transformer	0.010800		
9	480 V metal-clad circuit breaker	0.000210		
Total through 13.8 kV circuit breaker with 9 min switchover after a failure of source 1and source 2 is okay		**1.668384**	**0.250258**	**0.999971433**
	Loss of both 13.8 kV power sources simultaneously	0.312000	0.162240	0.999981480
Total to point G		**1.980384**	**0.412498**	**0.999952913**
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000038	0.000151	0.999999983
13	Cable (480 V); 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**1.990883**	**0.483814**	**0.999944773**

Table 3-14—Secondary-selective system—Failure rate and forced hours downtime per year at 480 V point of use (Example 5b), assuming a 5 s automatic transfer to utility power source No. 2

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.644000		
2	Primary protection and control system	0.000600		
3	13.8 kV metal-clad circuit breaker	0.001850		
4	13.8 kV switchgear bus—insulated	0.004100		
5	Cable (13.8 kV), 365.76 m (1200 ft), conduit playground	0.002124		
6	Cable terminations (9) at 13.8 kV	0.002960		
7	Disconnect switch (enclosed)	0.001740		
8	Transformer	0.010800		
9	480 V metal-clad circuit breaker	0.000210		
Total through 13.8 kV circuit breaker with 9 min switchover after a failure of source 1 (and source 2 is okay)		**0.00**	**0.0**	**1.000000000**
	Loss of both 13.8 kV power sources simultaneously	0.312000	0.162240	0.999981480
Total to point G		**0.312000**	**0.162240**	**0.999981480**
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000038	0.000151	0.999999983
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**0.322499**	**0.233556**	**0.999973339**

3.3.9 Example 6: Simple radial system with spare

3.3.9.1 Description

Figure 3-8 shows a one-line diagram of the power distribution system for a simple radial system. What are the failure rate and forced hours of downtime per year of the 480 V point of use if a spare transformer is available and can be installed as a replacement in these average times? The 7500 kVA transformer has the following repair and replacement with spare times—248 h repair time vs. 130.0 h to replace with a spare transformer.

The time to replace the transformer data are the actual values obtained from the IEEE Committee Report [B18].

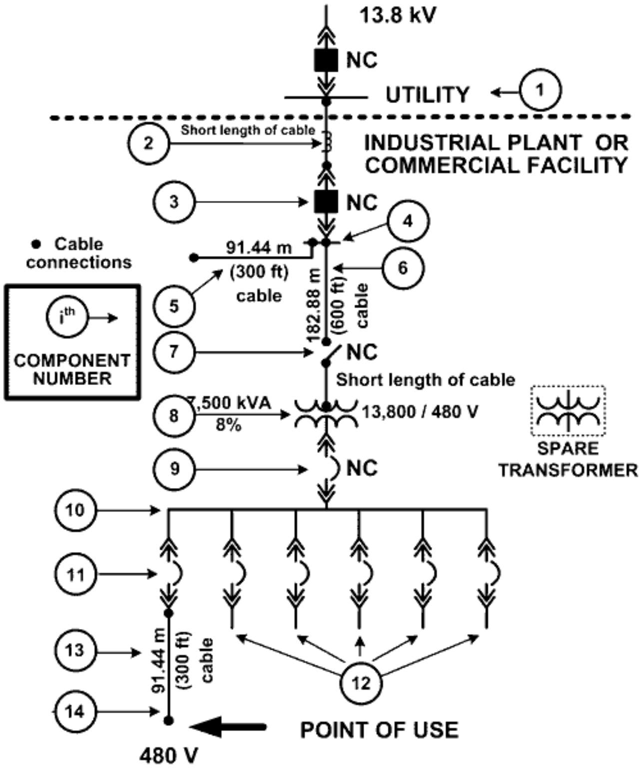

Figure 3-8—Simple radial system with spare—Example 6

3.3.9.2 Results

The results of the reliability and availability calculations are given in Table 3-15. They are compared with those of the simple radial system in Example 1 using average outage times based upon “repair failed unit.”

Table 3-15—Simple radial system with spare transformer—Failure rate and forced hours downtime per year at 480 V point of use (Example 6)

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.956000	2.582000	0.999705338
2	Primary protection and control system	0.000600	0.003000	0.999999658
3	13.8 kV metal-clad circuit breaker	0.001850	0.000925	0.999999894
4	13.8 kV switchgear bus—insulated	0.004100	0.153053	0.999982529
5	Cable (13.8 kV), 274.32 m (900 ft), conduit playground	0.002124	0.033347	0.999996193
6	Cable terminations (8) at 13.8 kV	0.002960	0.002220	0.999999747
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
8	Transformer—replace with spare when it fails—48 h	0.010800	0.518400	0.999940825
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V); 91.44 m (900 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable terminations (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**1.990940**	**3.367488**	**0.999615731**

The data for hours of downtime per failure are based upon *replace failed unit.*

3.3.9.3 Conclusions

The simple radial system with spares in Example 6 had a forced hours downtime per year that was 18.3% lower than the simple radial system in Example 1. If the spare replacement time were 48 h, then the forced hours of downtime per year would be approximately 21% lower than the simple radial system in Example 1. The failure rate at the 480 V point of use is unchanged.

3.3.10 Example 7: Simple radial system with cogeneration

3.3.10.1 Description

Figure 3-9 shows a single-line diagram of the power distribution system for a simple radial system with cogeneration. What are the failure rate and forced hours of downtime per year at the 480 V point of use, assuming the utility and cogeneration sources are operated in parallel?

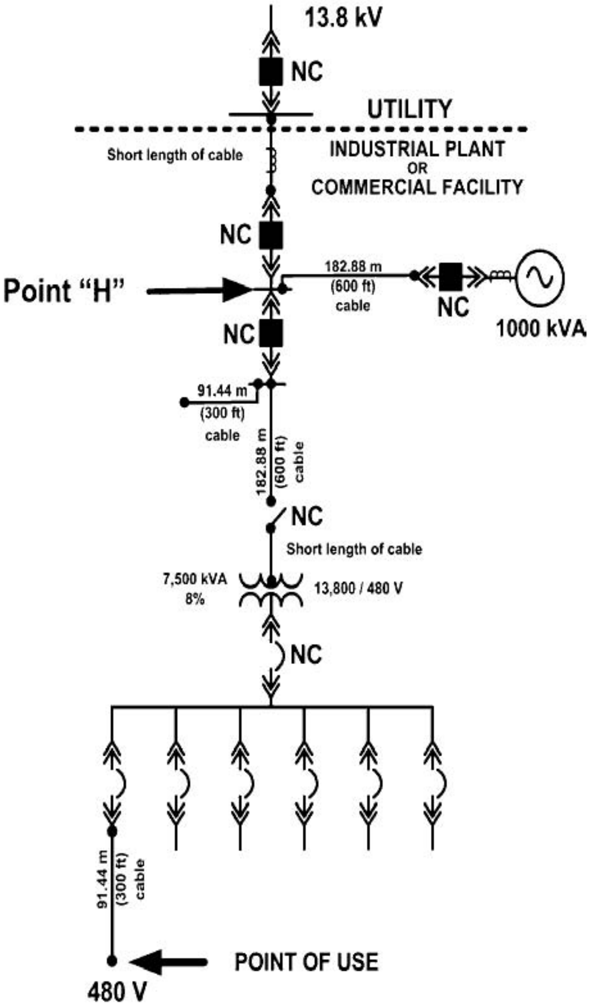

Figure 3-9—Simple radial system with cogeneration–Example 7

3.3.10.2 Results

The results from the reliability and availability calculations are given in Table 3-16.

3.3.10.3 Conclusions

The simple radial system in Example 1 yielded an average forced hours downtime per year that was about twice as large as the radial system with cogeneration in Example 7. The largest contributor to the average forced hours of downtime per year is the transformer; for example, if the transformer was replaced with a spare in 48 h, the downtime per year would 0.781933 h compared to 1.741527 h, and 0.522733 h compared to 1.741527 for a 24 h spare change out. The failure rate of the simple radial system was about 37 times larger than the radial system with cogeneration in Example 7.

Table 3-16—Simple radial system with cogeneration—Failure rate and forced hours downtime per year at 480 V point of use (Example 7)

Component number	Component	λ	λr	Ai
1	13.8 kV power source from electric utility	1.644000	2.582000	0.999705338
2	Primary protection and control system	0.000600	0.003000	0.999999658
	Cable connections (2) at 13.8 kV	0.000740	0.000555	0.999999937
3	13.8 kV metal-clad circuit breaker	0.001850	0.000925	0.999999894
	Utility source subtotal	**1.959190**	**2.586480**	**0.999704827**
	Local cogeneration			
	Generator (gas turbine)	1.727600	47.318964	0.994627313
	Control panel generator	0.011110	0.023442	0.999997324
	13.8 kV metal-clad circuit breaker	0.001850	0.000925	0.999999894
	Cable (13.8 kV), 182.88 m (600 ft), conduit playground	0.001416	0.022231	0.999997462
	Cable connections (2) at 13.8 kV	0.000740	0.000555	0.999999937
	Cogeneration subtotal	**1.742716**	**47.366117**	**0.994621988**
	Combined utility and cogeneration sources (assuming independent sources)	0.019470	0.047750	0.999994549
	13.8 kV switchgear bus—insulated	0.004100	0.153053	0.999982529

Table 3-16—Simple radial system with cogeneration—Failure rate and forced hours downtime per year at 480 V point of use (Example 7) *(continued)*

Component number	Component	λ	λr	Ai
	Total to point H	**0.023570**	**0.200803**	**0.999977078**
3	13.8 kV metal-clad circuit breaker	0.001850	0.000925	0.999999894
5	Cable (13.8 kV), 274.32 m (900 ft), conduit belowground	0.002124	0.033347	0.999996193
6	Cable connections (6) at 13.8 kV	0.002220	0.001665	0.999999810
7	Disconnect switch (enclosed)	0.001740	0.001740	0.999999801
8	Transformer	0.010800	1.430244	0.999836757
9	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
10	480 V switchgear bus—bare	0.009490	0.069182	0.999992103
11	480 V metal-clad circuit breaker	0.000210	0.001260	0.999999856
12	480 V metal-clad circuit breakers (5) (failed while opening)	0.000095	0.000378	0.999999957
13	Cable (480 V), 91.44 m (300 ft) conduit aboveground	0.000021	0.000168	0.999999981
14	Cable connections (2) at 480 V	0.000740	0.000555	0.999999937
	Total at 480 V point of use	**0.053069**	**1.741527**	**0.999801235**

3.3.11 Overall results from seven examples

The results for the seven examples are compared in Table 3-17 that shows the failure rates and the forced hours downtime per year at the 480 V point of use.

These data do not include outages for scheduled maintenance of the electrical equipment. It is assumed that scheduled maintenance will be performed at times when 480 V power output is not needed. If this is not possible, then outages for scheduled maintenance would have to be added to the numbers shown in Chapter 10. This would affect a simple radial system much more than a secondary-selective system because of redundancy of electrical equipment in the latter.

Table 3-17—Summary—Reliability and availability comparison at 480 V point of use for the seven power distribution system examples

Distribution system	Ex-ample	Switchover in less than 5 s		Switchover time 9 min		λ	λr
		λ	λr	λ	λr		
Simple radial	1					1.990940	4.279332
Simple radial with a spare transformer	6					1.990940	3.367488
Simple radial with cogeneration	7					0.053069	1.741527
Primary selective to 13.8 kV utility supply	2	0.344490	1.855647	1.990940	2.102614		
Primary selective to load side of 13.8 kV circuit breaker	3	0.345938	1.867318	1.992388	2.114285		
Primary selective to primary of transformer	4	0.333566	1.665287	1.992018	1.914055		
Secondary selective	5	0.322499	0.233556	1.990883	0.483814		

3.3.12 Discussion of reliability and availability analysis of common low-voltage industrial power distribution systems

3.3.12.1 Discussion—Definition of power failure

A failure of 480 V power was defined in the seven examples as a complete loss of incoming power for more than 5 s. This is consistent with the results obtained from the IEEE Committee Report [B18], which found a median value of 10 s for the “maximum length of power failure that will not stop plant production.”

3.3.12.2 Discussion—Electric utility power supply

Previous reliability studies (see Dickenson et al. [B6], Heising [B14], and Heising and Dunkijacobs [B15]) have drawn conclusions similar to those made in this chapter. All of these previous studies have identified the importance of two separate power supply sources from the electric utility. The Power System Reliability Subcommittee made a special effort to collect reliability data on double-circuit utility power supplies in an IEEE survey (see IEEE Committee Report [B17]). These data are summarized in Table 3-1 and were used in Examples 2 through 5. The two power sources in a double-circuit utility supply are not completely independent, and the reliability and availability analysis must take this into consideration. The importance of this point is shown in Table 3-1, where a reliability and availability comparison is made between the actual double-circuit utility power supply and the calculated value from two completely independent utility power sources.

The actual double-circuit utility power supply has a failure rate more than 200 times larger than two completely independent utility power sources. The actual double-circuit utility power supply data came from an IEEE survey (see IEEE Committee Report [B17]) and are based upon 77 outages in 246 unit-years of service at 45 plants with “all circuit breakers closed.” This is a broad composite from many industrial plants in different parts of the country.

It is believed that utility supply failure rates vary widely in various locations. One significant factor in this difference is believed to be different exposures to lightning storms. Thus, average values for the utility supply failure rate may not be valid for any one location. Local values should be obtained, if possible, from the utility involved, and these values should be used in reliability and availability studies.

Example 7 is included to show the reliability and availability improvement that could be obtained by using local generation rather than purchased power from an electric utility. It is of interest to note the very high reliability of local generation equipment found in the IEEE Committee Report [B18].

3.3.12.3 Other discussions

The reliability and availability analysis in the seven examples was done for 480 V low-voltage power distribution systems. It is believed that 600 V systems would have similar reliability and availability.

One of the assumptions made in the reliability and availability analysis is that the failure rate of the electrical equipment remains constant with age. It is believed that this assumption does not introduce significant errors in the conclusions. However, it is suspected that the failure rate of cables may change somewhat with age. In addition, data collected by the Edison Electric Institute on failures of power transformers above 2500 kVA show that the failure rate is higher during the first few years of service. See Table 3-7 for the results of an IEEE transformer reliability survey of industrial plants. The reliability data collected in other IEEE surveys (see IEEE Committee Report [B18]) did not attempt to determine how the failure rate varied with age for any electrical equipment studied. The mean time to repair (MTTR) a component can be dependent upon such factor as parts availability, craft training, preventive maintenance programs, available support from vendors and service shops, etc., and can significantly influence the reliability and availability of power systems.

A logical question to ask is, “How accurate are reliability and availability predictions?” It is believed that the predicted failure rates and forced outage hours per year are at best only accurate to within a factor of 2 to what might be achieved in the field. However, the relative reliability and availability comparison of the alternative power distribution systems studied should be more accurate than 2 to 1.

The Rome Air Development Center of the U.S. Air Force has had considerable experience comparing the predicted reliability of electronic systems with the actual reliability results achieved in the field. These results (see Feduccia and Klion [B9]) show that there is approximately a 12% chance that the field failure rate will be more than 2 to 1 worse than the reliability prediction made using a reliability handbook for electronic equipment (see *Reliability Stress and Failure Rate Data for Electronic Equipment* [B31]). It might be expected that the prediction of reliability of industrial power systems would have an accuracy similar to that obtained by the U.S. Air Force with electronic systems.

Some of the errors introduced when making reliability and availability predictions using published industry failure rates for the electrical equipment are as follows:

a) All details that could contribute to unreliability are not included in the study.

b) Some of the contributions from human error may not be properly included.

c) Equipment failure rates can be influenced by the adequacy of the preventive maintenance program used (see IEEE Committee Report [B18] and Wells [B34]). Contamination from the environment can also have an influence on equipment failure rates.

d) Correct conclusions can be made from statistical analysis on the average, but some plants will never experience these “average” problems. For example, several plants will never have a transformer failure.

In spite of these limitations, it is believed that reliability and availability analyses can be very useful in cost/reliability and cost/availability trade-off studies during the design phase of the power distribution system.

3.3.12.4 Spot network

A spot network would have a calculated reliability and availability approximately the same as the automatic throw-over secondary-selective system (see Heising [B14] and Heising and Dunkijacobs [B15]). In addition, it would have the benefit of no momentary outage in the event of a failure of any of the 13.8 kV cables or equipment since bus voltage is not lost on a spot network.

3.3.12.5 Protective devices other than drawout circuit breakers

The seven examples in this chapter used drawout circuit breakers as protective devices. Other types of protective devices are also available for use on power systems. The examples in this chapter attempted to show how to make reliability and availability calculations. No attempt was made to study the effect on reliability and availability of different types of protective devices or to draw conclusions that any particular type of protective device was more cost effective than another.

3.4 Cost of power outages

3.4.1 Cost of power outages and plant restart time

The forced hours of downtime per year is a measure of forced unavailability and is equal to the product of (failures per year λ average hours) × downtime per failure. The average downtime per failure could be called *restorability* and is a very important parameter when the forced hours of downtime per year are determined. The cost of power outages in an industrial plant is usually dependent upon both the failure rate and the restorability of the power system. In addition, the cost of power outages is also dependent on the "plant restart time" after power has been restored (see Gannon [B10]). The plant restart time would have to be added to the average downtime per failure when cost vs. reliability and availability studies are made in the design of the power distribution system.

The IEEE Committee Report [B18] found that the average plant restart time after a failure that caused complete plant shutdown was 17.4 h. The median value was 4.0 h.

3.4.2 *Order of magnitude* cost of interruptions

IEEE surveys (see Gannon [B10]) presented general data on the cost of interruptions to industrial plants and commercial buildings in the U.S. and Canada. Additional cost of interruption data is presented in various IEEE-IAS and IEEE-PES publications (see Billinton and Wacker [B1], Sullivan et al. [B32], Koval et al. [B23], and Patton et al. [B27]). The reader is again cautioned that such general data should be used only for order of magnitude evaluations where data specific to the system being studied is not available. A review of the reliability data can probably best be used in selecting the type of utility company service that should be provided.

Quantitative reliability assessments permit a cost-benefit analysis for every system reinforcement plan by including customer outage cost into the planning model before the reinforcement plan is implemented. Gauging the cost of customer outages, also known as *calculating customer damage functions* (CDF), was carried out by surveying customer groups—commercial, industrial and residential, and other company/organization customers—by asking them about their experience with outages, including frequency, duration, and the cost or inconvenience factor associated with outages. The cost of these outages varied according to customer group, and according to the season, time of day, and length of outage. A customer survey was conducted in 2002 by the MidAmerican Energy Company (Chowdhury et al. [B2]) and the cost of interruptions are shown in Table 3-18, Table 3-19, and Table 3-20 for commercial, industrial, and organizational/institutions customers. These interruption costs are presently the most recent published interruption costs available in the technical literature. The cost of interruptions in these tables are defined from various viewpoints, i.e., Table 3-18 represents the average interruption costs per event, Table 3-19 represents the average interruptions costs per annual kWh, and Table 3-20 represents the average interruption costs per kW demand. It is important to note that for an organization/institutional customer class the cost of a 2 s interruption is greater than a 20 min interruption due to the skewed distribution in the survey data that has a significant impact on the average value.

Table 3-18—Average per event interruption costs

Duration of interruption	Commercial (business) ($)	Industrial ($)	Organization/ institution ($)
2 s	na	na	28,565
1 min	379	14,155	na
20 min	744	20,551	15,373
1 h	1,002	33,436	21,878
4 h	2,299	61,710	53,455
8 h	4,188	92,210	na

Table 3-19—Average annual per kWh interruption costs

Duration of interruption	Commercial (business) ($)	Industrial ($)	Organization/ institution ($)
2 s	na	na	0.008768
1 min	0.00206	0.00200	na
20 min	0.00705	0.00343	0.004301
1 h	0.00857	0.00642	0.007487
4 h	0.02766	0.01236	0.017766
8 h	0.05146	0.02131	na

Table 3-20—Average per kW demand costs

Duration of interruption	Commercial (business) ($)	Industrial ($)	Organization/ institution ($)
2 s	na	na	31.54
1 min	9.03	8.98	na
20 min	30.87	13.08	13.48
1 h	37.52	23.41	21.10
4 h	121.15	40.19	53.32
8 h	225.41	67.15	na

3.4.3 Introduction to cost evaluation of reliability

An industrial power distribution system may receive power at 13.8 kV from an electric utility and then distribute the power throughout the plant for use at the various locations. One of the questions often raised during the design of the power distribution system is whether there is a way of making a quantitative comparison of the failure rate and the forced hours downtime per year of a secondary-selective system with a primary-selective system and a simple radial system. This comparison could be used in cost-reliability and cost-availability trade-off decisions in the design of the power distribution system. The estimated cost of power outages at the various plant locations could be factored into the decision as to which type of power distribution system to use. The decisions could be based upon “total owning cost over the useful life of the equipment” rather than “first cost.”

3.4.4 Cost data applied to examples of reliability and availability analysis of common low-voltage industrial power distribution systems

3.4.4.1 Cost evaluation of reliability and availability predictions

Cost evaluations were made of the reliability and availability predictions of five power distribution systems; examples will be presented. The revenue requirement (RR) method will be utilized in order to determine the most cost-effective system.

Although there are many ways in use to compare alternatives, some of these have defects and weaknesses, especially when comparing design alternatives in contrast to overall projects. The RR method is “mathematically rigorous and quantitatively correct to the extent permitted by accuracy with which items of cost can be forecast” (see Dickinson [B6] and Jeynes and Van Nemwegen [B18]).

The essence of the RR method is that for each alternative plan being considered, the minimum revenue requirements (MRR) are determined. This reveals the amount of product needed to be sold to achieve minimum acceptable earnings on the investment involved plus all expenses associated with that investment. These MMR for alternative plans may be compared directly. The plan having the lowest MRR is the economic choice.

MRR are made up of and equal to the summation of the following:

a) Variable operating expenses
b) Minimum acceptable earnings
c) Depreciation
d) Income taxes
e) Fixed operating expenses

These MRR may be separated into two main parts, one proportional and the other not proportional to investment in the alternative. This may be expressed Equation (3.7):

$$G = X + CF \tag{3.7}$$

where

G is the MRR to achieve minimum acceptable earnings
X is the nonfixed or variable operating expenses
C is the capital investment
F is the fixed investment charge factor

The last term in Equation (3.7), the product of C and F, includes the items b), c), d), and e) listed in the preceding paragraph. Equation (3.7) is now discussed.

X (variable expenses)—The effect of the failure of a component is to cause an increase in variable expenses. How serious this increase is depends to a great extent on the location of the component in the system and on the type of power distribution system employed. The quality of a component as installed can have a significant effect on the number of failures experienced. A poor quality component installed with poor workmanship and with poor application engineering may greatly increase the number of failures that occur as compared with a high-quality component installed with excellent workmanship and sound application engineering.

When a failure does occur, variable expenses are increased in two ways. In the first way, the increase is the result of the failure itself. In the second way, the increase is proportional to the duration of the failure.

Considering the first way, the increased expense due to the failure includes the following:

1) Damaged plant equipment
2) Spoiled or off-specification product
3) Extra maintenance costs
4) Costs for repair of the failed component

Considering the second way, plant downtime resulting from failures is made up of the time required to restart the plant, if necessary, plus the time to

- Effect repairs, if it is a radial system, or
- Effect a transfer from the source on which the failure occurred to an energized source.

During plant downtime, production is lost. This lost production is not available for sale, so revenues are lost. However, during plant downtime, some expenses may be saved, such as expenses for material, labor, power, and fuel costs. Therefore, the value of the lost production is the revenues lost because production stopped less the expenses saved. Some of the variable expenses may vary depending on the duration of plant downtime. For example, if plant downtime is only 1 h, perhaps no labor costs are saved. But, if plant downtime exceeds 8 h, labor costs may be saved.

If it is assumed that the value/hour of variable expenses does not vary with the duration of plant downtime, then the value of lost production can be expressed on a per hour basis, and the total value of lost production is the product of plant downtime in hours and the value of lost production per hour.

It should be noted that both the value of lost production and expenses incurred are proportional to the failure rate. The total effect on variable expenses, if the value of lost production is a constant on a per hourly basis, may be expressed by Equation (3.8):

$$X = \lambda[x_i + (g_p - x_p)\,(r + s)] \tag{3.8}$$

where

X is the variable expenses ($ per year)
λ is the failures per year or failure rate
x_i is the extra expenses incurred per failure ($ per failure)
g_p is the revenues lost per hour of plant downtime ($ per hour)
x_p is the variable expenses saved per hour of plant downtime ($ per hour)
r is the repair or replacement time after a failure (or transfer time if not radial system), in hours
s is the plant start-up time after a failure, in hours

For example assume that

λ is the 0.1 failure per year
x_i is the $55,000 per failure, extra expenses incurred
g_p is the $22,000 per hour, revenues lost
x_p is the $16,000 per hour, expenses saved
r is the 10 h per failure
s is the 20 h per failure

Then, variable expenses affected would be

$X = (0.1)[\$55{,}000 + (\$22{,}000 - \$16{,}000)(10 + 20)] = \$23{,}500$ per year

The term g_p represents revenues lost and it is not really an expense. However, it is a negative revenue, and as such, has the same effect on the economics as a positive expense item. It is convenient to treat it as though it were an expense.

A failure rate of 0.1 failure per year is equivalent to a mean time between failures (MTBF) of 10 years. These results can be expected since this is probability, but in a specific case, there might be two failures in one 10-year period and no failures in another 10-year period. But considering many similar cases, it is expected to have an average of 0.1 failure per year, with each failure costing an average of $235,000. This gives an equal average amount per year in the previous example of $23,500.

The point is that even though the actual failures cost $235,000 each and occur once every 10 years, a given failure is just as likely to occur in any of the 10 years. The equivalent equal annual amount of $23,500 per year is the average value of one failure in 10 years.

C (investment)—Each different alternative in an industrial plant power distribution system involves different investments. The system requiring the least investment will usually be some form of radial system. By varying the type of construction and the quality of the components in the system, the investment in radial systems can vary widely.

The best method is to find one total investment in each alternative plan. Another common method is to find the incremental investment in all alternatives over a base or least expensive plan. The main reason that the total investment method is preferable is that in comparing alternatives, the investment is multiplied by an *F* factor (which will be explained later). This factor is usually the same for alternative plans of the sort being considered here, but this is not necessarily the case.

Using the incremental investment may thus introduce a slight error into the economic comparisons.

F (investment charge factor)—This discussion of investment charge factor is taken from Dickinson [B6].

The factor *F* includes the following items that are constant in relation to the investment:

- Minimum acceptable rate of return on investment, allowing for risk
- Income taxes
- Depreciation
- Fixed expenses

Equation (3.9) is used to calculate the *F* factor:

$$F = \frac{(S_c a_L / f_r) - t d_t}{1 - t} + e \tag{3.9}$$

This may also take the form shown in Equation (3.10):

$$F = r + d + t + e \tag{3.10}$$

where

a_n	is $R + d_n$, amortization factor or leveling factor
d_n	is $R/(S_n–1)$, sinking fund factor
S_n	is the $(1 + R)^n$, growth factor or future value factor
n	is the period of years, such as c or L
c	is the years prior to start-up that an investment is made
L	is the life of investment years
R	is the minimum acceptable earnings per \$ of C (investment)
f_r	is the probability of success or risk adjustment factor
t	is the income taxes per \$ of C (investment)
d_t	is the income tax depreciation, levelized per \$ of C (investment) = $1/L$, $d_t = 1L$
e	is the fixed expenses per \$ of C (investment)
r	is the levelized return on investment per \$ of C (investment)
d	is the levelized depreciation on investment per \$ of C (investment)
t	is the levelized income taxes on investment per \$ of C (investment)
S_c	is $(1 + R)^c$
S_L	is $(1 + R)^L$
d_L	is $R/(S_{L\,-}\,1)$
a_L	is $R + d_L$

For example assume

L	to be 20 years, life of the investment
c	to be 1 year
R	to be 0.15, minimum acceptable rate of return
f_r	to be 1, risk adjustment factor
t	to be 0.5, income tax rate
d_t	to be $1/L = 0.05$
e	to be 0.0825

Then

S_c	is $(1 + R)^c = (1 + 0.15)^1 = 1.15$
S_L	is $(1 + R)^L = (1 + 0.15)^{20} = 16.37$
d_L	is $R/(S_L – 1) = 0.15/(16.37 – 1) = 0.0.0098$
a_L	is $R + d_L = 0.15 + 0.0098 = 0.1598$

Substituting into Equation (3.9) to calculate the F factor, results in $F = 0.04$

All the assumed values are believed to be typical for the average electric distribution system, except the value of $e = 0.0825$. This latter value was arbitrarily assumed to make R round-out to 0.4. The term e covers such items as insurance, property taxes, and fixed maintenance costs. A typical value is probably less than 0.0825.

It is believed that a typical value for minimum acceptable return on investment in many industrial plants is 15%, that is, $R = 0.15$. The company average rate of return, based on either past history or anticipated results, is a measure of what R should be. In plants of higher risk than the average, the risk adjustment factor, f_r, should probably be less than 1. However, company management determines what the value of R should be. The value of F can be calculated from Equation (3-9). In Dickinson [B5] tabular values are given for the factors S_n and a_n for various rates of return and plant lives.

3.4.4.2 Steps for economic comparisons

a) Prepare single-line diagrams of alternative plans and assign failure rates, repair times, and investment in each component, and determine the total investment C in each plan.

b) Determine X, the increased variable expense for each plan as the sum of the value of lost production and the extra variable expenses incurred.

c) Determine F, the fixed investment charge factor F from Equation (3.9).

d) Calculate $G = X + CF$, the MRRs G of each plan from Equation (3.7).

e) Select as the economic choice the plan having the lowest value of G.

3.4.4.3 Description of cost evaluation problem

Management insists that the engineer utilize an economic evaluation in any capital improvement program. The elements to be included and a method of mathematically equating the cost impact to be expected from electrical interruptions and downtimes against the cost of a new system were presented in this subclause. It was pointed out that there are several acceptable ways of accomplishing the detailed economic analysis for evaluation of systems with varying degrees of reliability. One of those considered acceptable, the RR method was presented in detail, and this method will be used in the analysis of four examples. The five example systems included are:

Example 1—Simple radial system—Single 13.8 kV utility supply

Example 2b—Primary-selective system to 13.8 kV utility supply (dual)—switchover time less than 5 s

Example 4—Primary-selective system to primary of transformer—13.8 kV utility supply (dual)—manual switchover in 9 min

Example 5b—Secondary-selective system with switchover time less than 5 s

Example 7—Simple radial system with cogeneration

Table 3-23 lists the expected failures per year and the average downtime per year for each of the examples. These data will be used to show which of the examples has the MRR making allowances for:

a) Plant start-up time
b) Revenues lost
c) Variable expenses saved
d) Variable expenses incurred
e) Investment
f) Fixed investment charges

One of the benefits of such a rigidly structured analysis is that the presentation is made in a sequential manner utilizing cost/failure data prepared with the assistance of management. With this arrangement, the results of the evaluation are less likely to be questioned than if a less sophisticated method was used.

3.4.4.4 Procedures for cost analyses

Utilizing the single-line diagrams for the five examples, a component quantity takeoff of each system was made, and the installed unit costs assigned for each component. In the case of the dual 13.8 kV utility company's supply, the basic cost of the second supply was estimated on the basis of a hypothetical case, assuming that a one-time only cost would be incurred. The extension of the costs results in the overall installed cost for each of the five examples. A summary of the installed costs for each example system is presented in Table 3-21 and Table 3-22. All the unit cost estimates are assumed for illustrative purposes. The utility service standby charge (i.e., a lump cost) is based on the assumption that the utility company's alternative primary service distribution system will require upgrading and a reserve capacity will be required in the utility company's substation. A lump sum (LS) of $250,000 is assumed in this analysis. The RR method will be used to calculate the total cost in dollars per year of both the "installed cost" and the "cost of unreliability" for the five examples.

Table 3-21—Installed costs of example systems 1, 2b, and 4

Item	**Unit cost ($)**	**Example 1 Simple radial system—single 13.8 kV utility supply**		**Example 2b Primary-selective system to 13.8 kV utility supply (dual)**		**Example 4 Primary-selective system to primary of transformer**	
		Quan-tity	**Total cost ($)**	**Quan-tity**	**Total cost ($)**	**Quan-tity**	**Total cost ($)**
Utility service standby charge— LS		—	—	LS	$250,000	LS	250,000
Basic equipment							
Medium-voltage circuit breaker, each	75	1	75	1	75	2	150
Medium-voltage circuit cable, linear feet	35	900	31,500	900	31,500	2100	73,500
1000 kVA transformer, each	100	1	100	1	100		100
1000 kVA transformer— 3-position switch, each	100					1	
1600 A low-voltage circuit breaker, each	25	1	25	1	25	1	25
600 A MCCB, each	15	6	90	6	90	6	90
Low-voltage cable, linear feet	5	300	1,500	300	1,500	300	1,500
Subtotal—basic equipment cost			33,290		33,290		75,365
Total cost		**33,290**		**283,290**		**325,365**	

NOTE—All installed costs are hypothetical and are solely for the purpose of illustrating the cost analyses methodology.

Table 3-22—Installed costs of example systems 5b and 7

Item	**Unit cost ($)**	**Example 5b Secondary-selective system**		**Example 7 Simple radial with cogeneration**	
		Quantity	**Total cost ($)**	**Quantity**	**Total cost ($)**
Utility service standby charge—LS		LS	250,000	—	—
LS cogeneration plant					350,000
Basic equipment					
Medium-voltage circuit breaker, each	75	2	150	3	225
Medium-voltage circuit cable, linear feet	35	1800	63,000	1500	52,500
1000 kVA transformer, each	100	2	200	1	100
1000 kVA transformer—3-position switch, each	100				
1600 A low-voltage circuit breaker, each	25	3	75	1	25
600 A MCCB, each	15	6	90	6	90
Low-voltage cable, linear feet	5	300	1,500	300	1,500
Subtotal—Basic equipment cost			65,015		54,440
Total cost		**315,015**		**404,440**	
NOTE—All installed costs are hypothetical and are solely for the purpose of illustrating the cost analyses methodology.					

3.4.4.5 Assumed cost values

The following common cost factors were assumed:

10 h/failure—Plant start-up time after a failure, s
$22,000/h—Revenues lost per hour of plant downtime, g_p
$16,000/h—Variable expenses saved per hour of plant downtime, x_p
$55,000/failure—Variable expenses incurred per failure, x_i
0.4 per year—Fixed investment charge factor, F

These values are shown in Table 3-23 after (2), (4), (5), (8), and (13), respectively.

Table 3-23—Sample reliability economics problem of example systems

		Example 1	Example 2b	Example 4	Example 5b	Example 7
1	r—Component repair time or transfer time to restore service, whichever is less, hours power failure	2.15	5.39	0.96	0.72	32.82
2	s —Plant start-up time, hours per failure	10.00	10.00	10.00	10.00	10.00
3	$r + s$	12.15	15.39	10.96	10.72	42.82
4	g_p—Revenues lost per hours of plant downtime, $/h	$22,000	$22,000	$22,000	$22,000	$22,000
5	x_p—Variable expenses saved, $/h	$16,000	$16,000	$16,000	$16,000	$16,000
6	$g_p - x_p$	$6,000	$6,000	$6,000	$6,000	$6,000
7	$(g_p - x_p)(r + s) =$ $/failure	$72,896	$92,320	$65,765	$64,345	$256,897
8	x_i—Variable expenses incurred per failure, $/failure	$55,000	$55,000	$55,000	$55,000	$55,000
9	Item (7) + (8) $/failure	$127,896	$147,320	$120,765	$119,345	$311,897
10	λ = failure rate per year	1.99	0.34	1.99	0.32	0.05
11	Item (9) × (10), X $/year	$254,634	$50,750	$240,566	$38,489	$16,552
12	C —Investment (installed costs)	$13,316	$283,290	$325,365	$315,015	$404,440

Table 3-23—Sample reliability economics problem of example systems *(continued)*

		Example 1	Example 2b	Example 4	Example 5b	Example 7
13	*F*—Fixed investment charge factor, per year	0.40	0.40	0.40	0.40	0.40
14	*CF* = Fixed investment charges, $/year	$13,316	$113,316	$130,146	$126,006	$161,776
15	*G* = *X* + *CF* (Items (11) + (14)], MRR, $/year	$267,950	$164,066	$370,712	$164,495	$178,328
	Economic choice		**Example 2b**			

3.4.4.6 Results and conclusions

The MMR for each of the five examples are shown in item (15) at the bottom of Table 3-23. Some of the conclusions that can be made are tabulated below:

Example 1— Simple radial system—single 13.8 kV utility supply

This system requires the least initial investment ($33,290); however, its MRR of $267,950 per year is the second highest of the five examples analyzed.

Example 2b—Primary-selective system to 13.8 kV utility supply (dual) with switchover time less than 5 s

This system requires an initial investment of $283,290; however, the MRR is $164,066 per year, which is the least of the five examples.

Based on the data presented, Example 2b would be selected since it has the lowest MRR.

Example 4—Primary-selective system to primary of transformer, 13.8 k V utility supply (dual)—manual switchover time of 9 min

This system shows next to highest initial cost of $325,365 and the highest MRR of $370,712 per year. A major contributor to the high MRR is the fact that while a dual system has been provided, the utility supplies' 9 min manual switchover requirement increases the failure rate and downtime to account for its high MRR. If an automatic switchover were utilized, the example would be competitive with Example 2b.

Example 5b—Secondary-selective system, with switchover time less than 5 s

This system requires the third highest initial investment ($315,015) and produces the second lowest MRR of $164,495 per year.

Example 7—Simple radial system with cogeneration

This system matches Example 5b (secondary-selective system with switchover time less than 5 s) with the highest initial investment of $404,440 and produces the third MRR of $178,328 per year.

3.5 IEEE Gold Book Standard Network

The U.S. Army Corps of Engineers PREP sponsored a survey effort to determine the various reliability/availability (R/A) analysis software tools available for utility, commercial and industrial electrical and mechanical R/A analysis. The different approaches identified (Coyle, Arno, and Hale [B3]) include:

a) Zone branch
b) Reliability block diagram (RBD)
c) Event tree
d) Monte Carlo
e) Boolean algebra
f) Failure modes, effects, and criticality analysis (FMECA)
g) Cut-set
h) Spreadsheet methodology

These analytical approaches will be analyzed and presented in this subclause to determine the accuracy of their results and how closely they can verify operational anomalies. The *IEEE Gold Book Standard Network* provides a means of evaluating existing and new computer programs designed to calculate the reliability of industrial power systems.

A reliable equipment data source is key to an accurate analysis. Data sources such as the *IEEE Gold Book*™ and the PREP database provide the user with the necessary data parameters to evaluate the reliability of industrial and commercial power system network configurations. These two equipment reliability data sources are based on extensive surveys over many years. An accurate understanding of component reliability and maintenance actions will provide the necessary availability indices for your reliability analysis approach.

A standard network was required to enable comparisons between different methodologies. After considerable examination of actual industrial and commercial power system network configurations the single-line diagram of the Gold Book Standard Network was defined and is shown in Figure 3-10. The equipment reliability data corresponding to each labeled component of the network is defined in Table 3-24.

There are many assumptions necessary to complete the reliability analysis of a network by any methodology, and these assumptions must be defined in order for their results to be meaningfully compared. The following assumptions are to be used by any reliability methodology applied to the Gold Book Standard Network:

1) Actual cable lengths are indicated on the drawings, modify failure rate accordingly. Example: Cable failure rate per rated length × of actual cable length indicated on the drawing.
2) M denotes manual operation and is allocated 15 min for activation.
3) Required generators, two out of four.
4) The uninterruptible power supplies (UPS) are redundant.
5) The PDU transformers are redundant.
6) Terminations, while normal for all systems, are not included on the drawings. For this analysis, terminations or splices are not included in the reliability calculations.
7) For breaker failure modes, assume 50% open and 50% shorted.

Fundamental assumptions necessary to follow the analysis are stated below. Greater detail on the development of the standard system configuration and the basis for selection of component indices can be found in Coyle, Arno, and Hale [B3].

— Utility services and switchgear are sized to carry the entire load from a single source (2N).
— Two out of four generators are required to carry the load (N+2).
— Manual switching operations require 15 min.
— Automatic starting and parallel of generators.

The Gold Book Standard Network is a dual utility source system with standby generation similar in configuration to many mission critical electrical systems serving both military and commercial facilities. The service transformers supply a double-ended 4000 A, 600 V bus, that we refer to as the *main switchgear*. This bus serves the critical load through UPS systems connected to circuits A and B. The downstream UPS system and critical distribution have not been modeled at this time. Mechanical equipment is served from the 800 A, 600 V double-ended bus, supplied from the main switchgear. The network is supplied by two independent 15 kV primary distribution feeders. There are four diesel engine generators at the facility where two out of four generators are required to meet the network load demands at all times. The reliability indices of the load points shown in Figure 3-10 (i.e., main bus A, main bus B, generation bus, mech bus A, mech bus B, lightning bus, and noncritical bus) will be evaluated by the three analytical methodologies. The following reliability indices will be evaluated:

— Frequency of load point interruptions (interruptions per year)
— Annual duration of load point interruptions (hours per year)
— Average duration of load point interruptions (hours per interruption)
— Reliability level of power supply to the load point

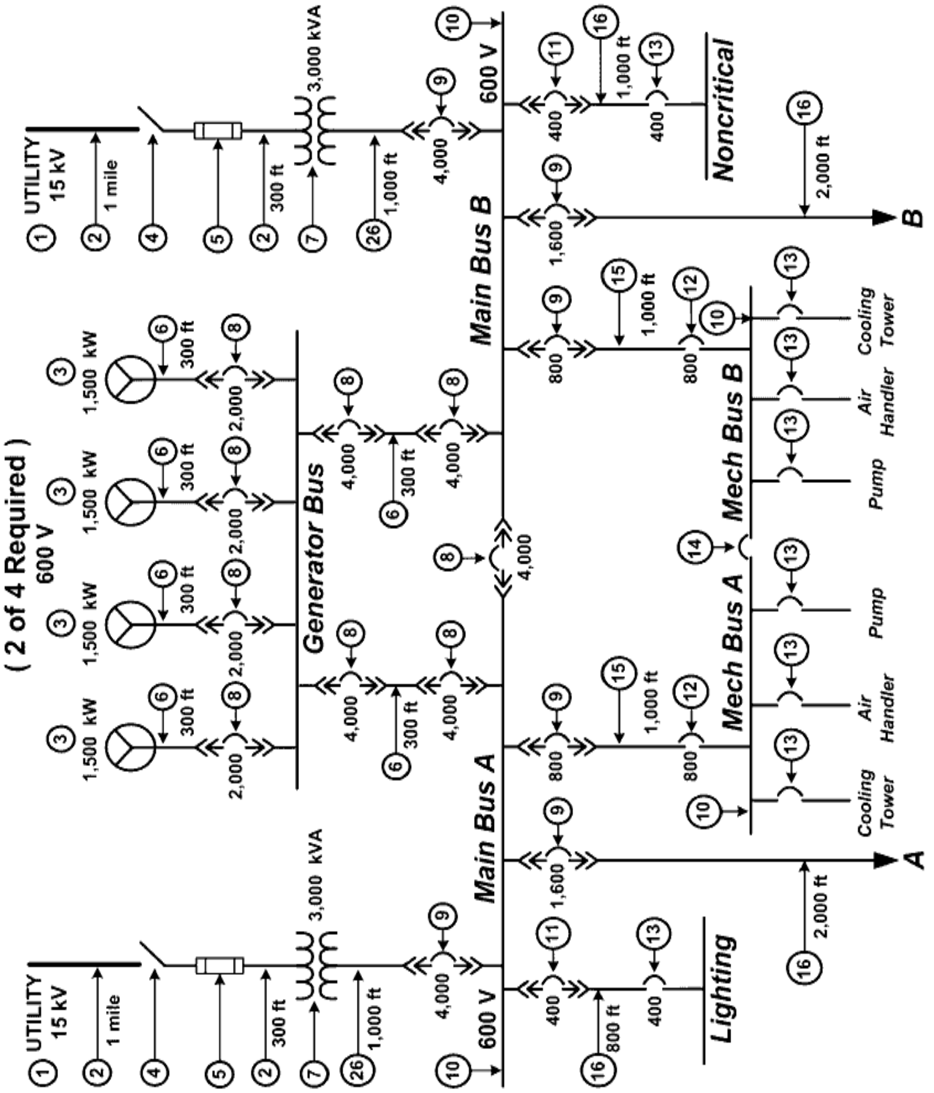

Figure 3-10—IEEE Gold Book Standard Network configuration

Table 3-24—Equipment reliability data for Gold Book Standard Network configuration

Ref #	Item description	Inherent reliability	MTTR (h)	Failure rate failure/ year	Calculated reliability
1	Single-circuit utility supply, 1.78 failures/unit years, A = 0.999705 (see 3.3.3)	0.999705	1.32	1.956	
2	Cable aerial, ≤ 15kV, per mile	0.99999022	1.82	0.047170	
2A	Cable trial, ≤ 15kV, 300 ft		1.82	**0.002680**	**0.99999944**
3	Diesel engine generator, packaged, standby, 1500 kW	0.99974231	18.28	0.123500	
4	Manual disconnect switch	0.9999998	1	0.001740	
5	Fuse, 15 kV	0.99995363	4	0.101540	
6	Cable belowground in conduit, ≤ 600 V, per 1000 ft	0.99999743	11.22	0.002010	
6A	Cable belowground in conduit, ≤ 600 V, 300 ft		11.22	**0.000603**	**0.999999228**
7	Transformer, liquid, nonforced air, 3000 kVA	0.99999937	5	0.001110	
8	Circuit breaker, 600 V, drawout, normally open, > 600 A	0.99999874	2	0.005530	
8A	Circuit breaker, 600 V, drawout, normally open, > 600 A		2	0.002765	0.999999369
9	Circuit breaker, 600 V, drawout, normally closed, > 600 A	0.99999989	0.5	0.001850	
9A	Circuit breaker, 600 V, drawout, normally closed, > 600 A		0.5	0.000925	0.999999947
10	Switchgear, bare bus, 600 V	0.9999921	7.29	0.009490	
11	Circuit breaker, 600 V drawout, normally closed, < 600 A	0.99999986	6	0.000210	
11A	Circuit breaker, 600 V drawout, normally closed, < 600 A		6	0.000105	0.999999928

Table 3-24—Equipment reliability data for Gold Book Standard Network configuration *(continued)*

Ref #	Item description	Inherent reliability	MTTR (h)	Failure rate failure/ year	Calculated reliability
12	Circuit breaker, 600 V, normally closed, > 600 A	0.99998948	9.6	0.009600	
12A	Circuit breaker, 600 V, normally closed, > 600 A		9.6	0.004800	0.999994740
13	Circuit breaker, 3-phase fixed, normally closed, ≤ 600 A	0.99999656	5.8	0.005200	
13A	Circuit breaker, 3-phase fixed, normally closed, ≤ 600 A		5.8	0.002600	0.999998279
14	Circuit breaker, 3-phase fixed, normally open, > 600 A	0.99998532	37.5	0.003430	
14A	Circuit breaker, 3-phase fixed, normally open, > 600 A		37.5	0.001715	0.999992658
15	Cable, aboveground, no conduit, ≤ 600 V, per 1000 ft	0.99999997	2.5	0.000120	
15A	Cable, aboveground, no conduit, ≤ 600 V, per 1000 ft		2.5	**0.000096**	**0.999999973**
16	Cable, aboveground, trays, ≤ 600 V, per 1000 ft	0.99999831	10.5	0.001410	
	Cable, aboveground, trays, ≤ 600 V, per 1000 ft		10.5	**0.002820**	**0.999996620**
22	Switchgear, insulated bus, ≤ 600 V	0.99999953	2.4	0.001700	0.999999534
26	Bus duct, per circuit foot	0.99999982	12.9	0.000125	0.999815959

Calculated reliability indices for the selected output buses are shown in Table 3-25, Table 3-26, and Table 3-27 for each reliability methodology. The detailed calculation of these indices, as well as the calculation of the indices for the defined events, are found in Koval [B22], Coyle, Arno, and Hale [B4], Koval et al. [B24], Patton et al. [B27], and Hale, Arno, and Koval [B13].

The calculated inherent availabilities are high, in excess of 5-9's, for the main and generator buses and slightly less than that for the mechanical and noncritical buses. In our experience, these values are typical of those obtained by other methods for systems of similar configuration. A comparison and discussion of the results of the different methods is presented in Table 3-28.

Table 3-25—Calculated reliability indices at output buses—Spreadsheet reliability methodology

Output location	Failure rate, per year	Failure duration (h)	Downtime (h/y)	Ai
Main switchgear bus A	0.015135	5.069684	0.076730	0.999991241
Main switchgear bus B	0.015135	5.069684	0.076730	0.999991241
Generation bus	0.015530	2.043786	0.031740	0.999996377
Mechanical switchgear bus A	0.044785	5.019912	0.224817	0.999974337
Mechanical switchgear bus B	0.044785	5.019912	0.224817	0.999974337
Lighting bus	0.020536	5.247354	0.107760	0.999987699
Noncritical bus	0.021850	5.598384	0.122325	0.999986036

Table 3-26—Calculated reliability indices at output buses—GO reliability methodology

Output location	Failure rate, per year	Failure duration (h)	Downtime (h/y)	Ai
Main switchgear bus A	0.015135	5.075996	0.076825	0.999991230
Main switchgear bus B	0.015135	5.075996	0.076825	0.999991230
Generation bus	0.015530	2.087057	0.032412	0.999996300
Mechanical switchgear bus A	0.023841	4.188664	0.099864	0.999988600
Mechanical switchgear bus B	0.023841	4.188664	0.099864	0.999988600
Lighting bus	0.020536	5.251052	0.107836	0.999987690
Noncritical bus	0.020536	5.255317	0.107923	0.999987680

Table 3-27—Calculated reliability indices at output buses—Minimal cut-set reliability methodology

Output location	Failure rate, per year	Failure duration (h)	Downtime (h/y)	Ai
Main switchgear bus A	0.017895	4.595114	0.082230	0.999990613
Main switchgear bus B	0.017895	4.595114	0.082230	0.999990613
Generation bus	0.015530	2.043786	0.031740	0.999996377
Mechanical switchgear bus A	0.023841	9.484818	0.226132	0.999974186
Mechanical switchgear bus B	0.023841	9.484818	0.226132	0.999974186
Lighting bus	0.020696	4.743891	0.098180	0.999988792
Noncritical bus	0.012315	7.387812	0.090981	0.999989614

3.5.1 Comparison of results

Table 3-28—Comparison of availability indices generated by the different methodologies

Output location	Spreadsheet reliability model	GO reliability methodology	Minimal cut-set reliability methodology
Main switchgear bus A	0.999991241	0.999991230	0.999990613
Main switchgear bus B	0.999991241	0.999991230	0.999990613
Generation bus	0.999996377	0.999996300	0.999996377
Mechanical switchgear bus A	0.999974337	0.999988600	0.999974186
Mechanical switchgear bus B	0.999974337	0.999988600	0.999974186
Lighting bus	0.999987699	0.999987690	0.999988792
Noncritical bus	0.999986036	0.999987680	0.999989614

The availability indices at each output location within the Gold Book Standard Network calculated by the various methodologies are in close agreement. The differences are dependent upon the unique characteristics of each model (e.g., minimal cut-set, the number of cut-sets considered). Similar comparison of the other reliability indices (i.e., failure rate, failure duration, and downtime) can be made. The major difference between the minimal cut-set methodology and the spreadsheet methodology are the indices at the mechanical switchgear bus A and B, which were attributed to internal model assumptions on handling redundant paths and common mode failures that were not considered at the time of publication of the original papers.

3.5.2 Gold Book Network conclusions

It is very difficult to compare reliability models unless the network configuration, equipment reliability parameters, network operating configurations, switching, and network reconfiguration procedures are standardized. This subclause has presented the basic single line diagram and equipment reliability data for the IEEE Gold Book Standard Network configuration. It provides the means of evaluating the accuracy of different reliability methodologies.

3.6 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

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Chapter 4
Evaluating and improving the reliability of an existing electrical system

4.1 Introduction

Traditionally, efforts to improve the reliability of electrical service within an industrial plant or other facility with critical power requirements have focused on increasing the reliability of the electric utility supply. Facility operators may not be in a position to improve the reliability of their utility supply, such improvements may be very costly, and they will have no impact on outages resulting from internal failures. Facility operators, as a result, must also focus their attention on critical areas within their own system. A logical approach to the analysis of options available in the electrical system (in terms of both utility supply and facility distribution) will lead to the greatest reliability improvement for the least cost. In many instances, reliability improvements can be obtained without any capital cost by making the proper inquiries.

A thorough and properly integrated investigation of the entire electric system will pinpoint the components or subsystems having unacceptable reliability. Some important general inquiries follow. Many of these questions apply to both the utility and the plant distribution systems.

a) How is the system supposed to operate?
b) What is the physical condition of the electric system?
c) What will happen if faults occur at different points?
d) What is the probability of a failure and its expected duration?
e) What is the critical duration of a power interruption that will cause significant financial loss? (That is, will momentary or short-duration interruptions cost production dollars or merely be an inconvenience?)
f) Are critical loads (those necessary to sustain production or the mission of the facility) segregated from noncritical loads?
g) Is there any fire or health hazard that will be precipitated by an electrical fault or a power loss?
h) Is any equipment vulnerable to voltage dips or surges?

The answers to these and similar questions, if properly asked, can and will result in savings to the facility operator (but only if they are acted upon).

A question at this point should be, “How do I get started?” However, another question could be, “Why bother?” The answer to the former question is covered in this chapter, and the answer to the latter question is based on the following analogy. When preparing for a long trip, a motorist will make sure that their car is in good working condition before leaving. The motorist will check the brakes, engine, transmission, tires, exhaust system, etc., to see that they are in good condition and make the required repairs. For the motorist knows that “on-the-road” breakdowns and failures are expensive, time consuming, and can be hazardous. In an industrial plant or critical facility, an unplanned electrical failure will consume valuable production time as well as dollars and may cause injury to personnel. Circuit breakers, relays, meters, transformers, wireways, etc., need periodic checks and preventive maintenance (see Chapter 5) to improve the likelihood of trouble-free performance. Some plants have been shut down completely by events such as a ballast failure. These "shutdowns" are commonly caused by improper settings in protective devices, circuit breaker contacts that were welded shut, or relays that were not set (or did not react) properly. This chapter shows the facility engineer how to minimize downtime by analyzing the system.

4.2 Evaluation methodology

Evaluation of the reliability of an existing electrical system should include review of the system at a number of levels:

4.2.1 Utility supply

The 1974 survey of electrical equipment reliability in industrial plants (see IEEE Committee Report [B4])[1] and subsequent investigations showed the utility supply to be the largest single component affecting the reliability of an industrial plant. (See Table 3 in Annex A and Table 10-35.)

Most customers simply "hook up" to the utility system and do not fully recognize that their reliability requirements can have an impact on how the utility supplies them. A utility is somewhat bound by the system available at the customer site and the investment that can be made per revenue dollar. However, most utilities are willing to discuss the various supply systems that are available to their customers. Many times, an option is available (sometimes with financial sharing between the user and the utility) that will meet the exact reliability needs of a specific facility.

4.2.2 Configuration

The system configuration, as determined from the one-line diagram, determines the inherent reliability that can be obtained from the system without adding or rearranging components. This should be the first level of analysis, in which vulnerabilities due to single paths, common-mode failure points, capacity shortfalls, etc., can be identified.

4.2.3 Control and protection

One level below the configuration is the control and protection system. Even if the system configuration is adequate to provide the required level of reliability, its performance can be compromised by failure of the control and protection system. Controls such as automatic bus transfer schemes and standby generator starting systems must function properly to make alternate paths or sources of power available to the load on failure of the primary source. Protective devices must be selectively coordinated to isolate the load from

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[1] The numbers in brackets correspond to those of the bibliography in 4.11.

faulted portions of the system and prevent faults on one path or in one portion of the system from causing interruption of multiple paths or sources.

4.2.4 Physical installation

The physical configuration and location of electrical equipment should be reviewed. Is the equipment adequately protected from physical damage and environmental hazards? Are redundant paths provided with physical segregation so that a major failure of one piece of equipment cannot readily propagate to redundant circuits or equipment?

4.2.5 Operations and maintenance

Finally, operations and maintenance (O&M) practices are critical to achieving the designed-in reliability of the system. Effective commissioning helps assure that control and protection systems function per design. Preventive maintenance can reduce failure rates and an adequate level of spare parts stocking can reduce repair times when failures do occur. Effective policies, procedures, documentation, and training of O&M personnel reduce outages due to human activity and improves operator response time when failures occur.

4.3 Utility supply availability

Loss of incoming power will cause an interruption to critical areas unless alternate power sources are available. Therefore, the reliability of the incoming power is of paramount importance to the facility engineer. It can be stated that different facilities and even circuits within a facility vary in their response to loss of power. In some cases, operations will not be significantly affected by a 10 min power interruption. In other cases, a 10 ms interruption will cause significant impact. The engineer should assess the operational vulnerability and convey the requirements to the local utility, as well as to their own management. (See 3.3.3 and 3.4 for information on economic loss vs. unavailability of incoming power.)

4.3.1 Use of historical data

For existing circuits and substations, the utility should be able to supply a listing of the frequency, type, and duration of power interruptions over the preceding 3 to 5 year period. They should also be able to predict the future average performance based on historical data and planned construction projects. For new circuits, the utility may be able to supply the historical performance of other circuits of similar length and construction near the facility under investigation. The user of utility-supplied outage rate information should be cautioned, however, that the definition of *outage* needs to be clarified with the utility. In some cases interruptions of 5 s or less, or reclosure operations that do not result in a lockout, are not counted as outages due to reporting agreements between utilities and regulatory bodies.

A second alternative would be to obtain a diagram of the utility supply system and evaluate its availability using Chapter 2 methods. As a last resort, the average numbers in this recommended practice will provide a good base (see Table 10-35).

The utility's history of interruptions can be compared with recorded dollar losses in verifying process vulnerability. By assigning a dollar loss to each interruption, it may be possible to determine a relationship between the duration of a power loss and a monetary loss for a particular facility. When the actual outage cost is higher or lower than would be predicted, the cause of the deviation should be determined. For example, a 15 min power loss at a shift change will be less costly than one during peak production. With a refined cost formula in hand, the cost of available options vs. projected losses can be evaluated.

Occasionally a facility experiences problems at times other than during a recorded outage. These problems may be caused by voltage sags or, more rarely, voltage swells that are difficult to trace. With problems such as these, it is necessary to begin recording the exact date and time of these occurrences and ask the utility to search for faults or other system disturbances at or near the specific times that they have been recorded. It would be wise to convey the fault times to the utility reasonably soon after the fault. It must be emphasized that unless these problems are significant in terms of dollars lost, safety, or frequency, it is not reasonable to pursue the cause of voltage dips since they are a natural phenomenon in the expansive system operated by a utility. Frequent dips can be caused by large motor starts, welder inrush, or intermittent faults in the plant's distribution system or even a neighbor's system.

4.3.2 Operational Issues

It is also reasonable to cover "what if" questions with the utility and to weigh their answers in any supply decision. A list of questions include the following:

a) How long will the plant be without power if
    1) The main transformer fails?
    2 The feed to the main transformer fails?
    3) The pole supporting the plant feed is struck by a vehicle and downed?
    4) The utility main line fuse or protector interrupts?
    5) The utility main feed breaker opens for a fault?
    6) The utility substation transformer fails?
    7) The utility substation feeds are interrupted?
b) What kind of response time can be expected from the utility for loss of power
    1) During a lightning storm?
    2) During a low trouble period, that is, under "normal" conditions?
    3) During a snow or ice storm?
    4) During long periods of high temperatures?
c) What should be done when the plant experiences an interruption
    1) Who should be called? A name and number should be made available to *all* responsible personnel. Alternates and their numbers should also be included.

    2) What information should be given to those called?
    3) How should plant people be trained to respond?
    4) Can plant personnel restore power by switching utility lines, and who should be contacted to obtain permission to switch?

d) Are there any better performing feeders near the plant, and what is the cost of extending them to the plant?
    1) Is this additional feeder from the same bus, from a different bus at the same station, or from another station?
    2) What is the probability (frequency and duration) of both the main and the backup feeder being interrupted simultaneously?
    3) What is the reliability improvement obtained from the additional or alternate feeder?

e) Will the utility's protective equipment coordinate with the service overcurrent protection? If not, what can be done to coordinate these series protective devices?

f) What is the available short-circuit current, and are there plans to change the system that will affect the short-circuit current?

g) How will future load growth affect the capacity and reliability of the feeders?

These questions may not apply to all facilities, but should be matched with specific user requirements.

4.3.3 Multiple sources

An important question to ask when multiple sources are employed to increase reliability is whether the sources should be operated in parallel or should be isolated, with an automatic transfer control scheme to switch from a failed source to the alternate source. If the sources are isolated, a fault on one source will only affect the parts of the facility served from that source, and the duration of the outage to those loads depends on the timing of the automatic transfer scheme, but is typically at least several seconds. If the sources are operated in parallel, both sources will experience a voltage dip for a fault on either source, affecting all of the facility, but with a duration limited to the clearing time of the faulted circuit. Which of these conditions is preferable depends on the type of loads and the details of the electrical system of the specific facility. For the most critical loads, application of a spot network system, in which multiple step-down transformers served by different primary feeders are operated in parallel through secondary network protectors, can provide high reliability, although at a correspondingly high cost.

The degree of independence of the sources is also important to determining the available improvement in reliability. Multiple utility distribution feeders should preferably come from different substations. If this is impractical or too costly, they should at least originate from different buses within the same substation, so that they are not simultaneously exposed to voltage dips from faults on other distribution feeders or to substation bus outages. Even feeders from different substations are likely to be exposed simultaneously to momentary voltage dips associated with transmission or subtransmission system faults.

Finally, the available standby capacity on each source that the utility is willing to dedicate to the facility should be investigated. It is common for utilities to use multiple interties to permit distribution feeders to back one another up. A feeder that has adequate capacity to carry the entire facility load under normal conditions may not have that capacity available if there have been multiple feeder outages and it is being used to back up other feeders.

4.4 Configuration

4.4.1 Where to begin—One-line diagram

The "blueprint" for electrical analysis is the *one-line diagram*. The existence of an up-to-date one-line diagram is essential for any plant electrical engineer, manager, or operator. It is the "road map" of the electric system. In fact, a current one-line diagram should exist (or be prepared) even if the ensuing analysis is not done.

The one-line diagram should begin at the incoming power supply. Standard IEEE symbols should be used in representing electrical components (see IEEE Std 315™).[2] It is usually impractical to show all circuits in a plant on a single schematic, so the initial one-line diagram should show only major components, circuits, and panels. More detailed analysis may be required in critical areas, and additional one-line diagrams should be prepared for these areas as required.

Since an analysis is being made from the one-line diagram, the type, size, and rating of each device as well as its availability should be shown on the diagram. The diagram should include at least the following information:

a) Incoming utility service: voltage, capacity and rating basis
b) On-site generators
c) Incoming main fuses, potheads, cutouts, switches, and main and tie breakers
d) Power transformers: rating, winding connection, and grounding means
e) Feeder breakers and fused switches
f) Relays: function, use, and type
g) Potential transformers: size, type, and ratio
h) Current transformers: size, type, and ratio
i) Control transformers
j) All main cable and wire runs with their associated isolating switches, splices, and terminations including length of run
k) All substations, including integral relays and main panels, and the exact nature of the load on each feeder and on each substation

If numerical reliability analysis is anticipated, the individual components defined in Chapter 3 should be identified and the one-line diagram should represent, to the greatest extent practical, the physical as well as electrical connections within the system. For

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[2] Information on references can be found in 4.10.

example, it makes a difference in calculation whether a connection between two cables occurs by "double-lugging" two sets of terminations at a switch or circuit breaker, by splicing the cables in a manhole, or by using load-break junctions in an aboveground cabinet. If space permits, additional information such as available short-circuit currents at each bus, date of equipment installation, and the reliability data for the individual components may be included. Including failure rate and duration information for every component on a one-line uses up white space very quickly; a recommended alternative is to develop a table of the component data applicable to the system with a numerical or alphabetical key for each entry and show only the appropriate key for each component on the one-line diagram. It is preferable to use historical reliability data for the specific facility if available and statistically valid.

The one-line diagram may show planned, as well as actual, feeder circuit breaker and substation loads based on actual measurements. In most facilities, load is added or deleted in small increments, and the net effect is not always seen until some part of the system becomes overloaded or underloaded. Many times, circuits are added without appropriate modification of the existing settings on the associated upstream circuit breakers. In addition, original designs may not have included special attention to the critical areas of production. With these thoughts in mind, the following information should be added to the one-line diagram:

1) The original system should be identified. The exact nature of the new loads and their approximate locations should be noted.
2) Critical areas of the system should be highlighted.
3) The component reliability data key should be inserted so that the reliability performance of the revised system can be analyzed on an "if new" basis.

For complex systems, it is beneficial to create an overall one-line diagram at a reduced level of detail that permits viewing the entire system topology on a single sheet. It is advantageous to include the incoming supply, switchgear, main feeders, substations, secondary tie circuits, and major equipment such as large motors or other concentrated loads on the overall diagram. This can be supplemented by drawings containing full detail of relaying, metering, and substation loads at larger scale spread over several sheets. After completion of the one-line diagrams, a comprehensive analysis can begin. However, the general inspection described in 4.6 can, and should, be performed concurrently with the preparation of the one-line diagram(s).

The one-line diagram is a picture of an ever-changing electric system. The efforts in preparing the diagram and analyzing the system should, therefore, be augmented by a means to capture new pictures of the system with actual or proposed changes. Therefore, a procedure should be formalized to ensure that all proposals undergo reliability scrutiny as well as one-line diagram update, and that their effect on the total system is analyzed before the proposal is approved. This process not only maintains the integrity of the system, but it also minimizes expense by more effectively utilizing existing facilities.

4.4.2 Circuit analysis and action

The first subsequent investigation, following completion of the plant one-line diagram, is the analysis of the system to pinpoint design problems. Key critical or vulnerable areas and overdutied or improperly protected equipment can be located by the following procedure:

a) Assign faults to various points in the system and note their effect on the system. For example, assume that the cable supply to the air conditioning compressor failed.
    1) How long could operations continue?
    2) Is any production cooling involved?
    3) Are any computer rooms cooled by this system?
b) What would happen if a short circuit or ground fault occurred on the secondary terminals of a unit substation? Consideration should be given to relay action (including backup protection), service restoration procedures, etc., in this "what if" analysis. This review could be called a failure mode and effects analysis (FMEA).
c) Calculate feeder loads to verify that all equipment is operating within its rating, including current transformers and other auxiliary equipment. Graphic or demand ammeters should be used to gather up-to-date information.
d) Fault duties should also be considered (see Chapter 5 in IEEE Std 141™, *IEEE Red Book™).* If a current short-circuit study is not available, one should be performed. When performing reliability analysis, equipment that is not properly rated for the available fault current at its location must be considered to be likely to fail to interrupt downstream faults, propagating all outages in its protected zone to the next upstream device.

Obviously, overloaded equipment should be replaced or load transferred so that the equipment can be operated well within its rating. The major projection points—outside the critical areas—should be capable of keeping the system intact by clearing faults and allowing the critical process to continue. The probability of jeopardizing the critical circuits by extraneous electrical faults should be minimized, either by physically isolating the critical circuits or by judicial use and proper maintenance of protective devices to electrically sever and isolate faults from critical circuits.

4.5 Assessing control and protection

The one-line diagram previously developed should provide the basic information required to begin an assessment of whether the control and protection system design will support the reliability level that the system configuration is intended to provide. Protective relays should be identified by ANSI device type number; instrument transformer ratios and connections should be shown and tripping logic indicated either by dashed lines between devices or by a tripping schedule. For complicated systems, separate instrumentation and relaying one-line diagrams may be required to supplement the overall one-line diagrams.

Perform a protective device coordination analysis [see IEEE Std 242™ *(IEEE Buff Book™)* or Chapter 4 in IEEE Std 141™ *(IEEE Red Book™)*. Protection for critical systems should be designed to meet three objectives:

a) Sensitive and high-speed clearing to minimize the depth and duration of voltage dips associated with faults.
b) Selective coordination to limit the outage to the affected portion of the system.
c) Security against nuisance tripping due to load characteristics and system transients.

The following questions should be asked in reviewing the results of the coordination study:

1) Are the relays and fuses properly set or rated for the current load levels?
2) Is there any new load that has reduced critical circuit reliability (or increased vulnerability)?
3) Are there any areas where selective coordination is not achieved? If so, can this be remedied through different device settings or is it unavoidable? If unavoidable, the impact of nonselective tripping should be assessed. If the affected circuits are not critical, it may be acceptable, whereas if it would impact critical circuits, corrective measures such as redistributing critical loads or relay upgrades should be considered.
4) Are critical circuits provided with both primary and secondary or backup protection so that a relay failure does not leave critical equipment unprotected or require transfer tripping to an upstream device affecting redundant circuits?

Switchgear control systems providing automatic response to outages and restoration of service through an alternate source or standby generation should be reviewed for their reliability. If a single control system is associated with redundant electrical sources or circuits, control system vulnerabilities may compromise the reliability built into the power system. Control system review may address the following:

- Is the design fail-safe, such that processor failure or other component failure will leave the electrical system “as is,” or can control failures cause unwanted breaker operations?
- Are redundant or highly reliable control power sources used?
- Is the control system provided with effective transient voltage suppression and properly designed grounding to prevent misoperation due to lightning or switching surges?
- Are there redundant processors or provisions for ready manual operation in the event of processor failure?
- Are operator control layouts designed to minimize human error through the use of status feedback, color coding, mimic buses, clear labeling, etc.?
- Was the control system thoroughly commissioned, and is it regularly tested?
- Are complete written sequences of operation available and familiar to the personnel responsible for operating and maintaining the system?
- Are the complete schematic and wiring diagrams available?

4.6 Physical assessment

A thorough inspection of the physical condition of a plant's distribution system can be utilized, hopefully on a continual basis, to improve reliability (see Chapter 5). All systems serving critical loads or processes should be part of a comprehensive preventive and predictive maintenance (PPM) program, which combines periodic visual inspections of equipment with mechanical and electrical testing to identify and correct deteriorating conditions before they result in unscheduled outages. If such a program has not been in place for the system being assessed, a thorough initial round of inspection and testing is recommended as providing the following benefits:

a) Immediate identification of conditions that may cause failures in the short term.
b) An indication of the general conditions of maintenance of the system that can be used in reliability calculations to select failure rate multipliers as discussed in 5.3.
c) Establishing baseline testing values that can be used to start trend monitoring as part of a PPM program.

Guidelines for inspection and testing of electrical equipment can be found in the relevant IEEE and ANSI standards documents, in the manufacturer's instruction manuals, in NFPA 70B-2006 [B3], and in the standards of the International Electrical Testing Association (NETA) [B4], and we will not attempt to repeat this information here. It is recommended that these sources be consulted and written checklists and procedures appropriate to the specific types of equipment and the system being assessed be prepared prior to undertaking the initial inspection and testing.

In addition to the inspection of the equipment itself, other physical conditions that can impact reliability should be considered. Physical construction of switchgear may compromise the independence of components that appear to be completely redundant to each other on the one-line diagram. A significant fraction of electrical equipment failures stem from nonelectrical causes such as human activity, physical contamination, and failure of environmental systems, with contamination from leakage of steam, water, or other process fluids leading the list. The physical assessment should address such questions as:

1) Is the installation secure from access by unauthorized or unqualified persons?
2) Do enclosures or locations effectively exclude small animals such as squirrels, snakes, and vermin from entering equipment?
3) Are barriers, such as bollards, provided to protect equipment from vehicles in locations subject to car, truck, or forklift traffic?
4) Are the areas around electrical equipment kept clear of storage and other obstacles that interfere with ready access for O&M?
5) Are working clearances in compliance with applicable codes and safe work rules?
6) Is piping and ductwork kept clear of the equipment, or is it adequately protected by drip-proof enclosures, double-walled piping, or drip pans?
7) Are items of critical equipment that are redundant to one another provided with segregation to reduce the likelihood of failure in one unit spreading to the other, or

of an external event such as mechanical damage, water leakage, or fire affecting both?

8) Is switchgear provided with internal barriers between redundant circuits and buses to prevent arcing faults from affecting multiple circuits?
9) Is ventilation, heating, and cooling equipment serving electrical equipment rooms in working order? Are temperatures monitored to promptly detect failure of environmental control?
10) Are air supplies filtered and drawn from areas of the facility that are unlikely to result in exposure of the equipment to high levels of humidity or to conductive or corrosive materials?
11) Are duct-bank, conduit, and busway entries properly sealed against movement of air between the outside environment and the electrical room and switchgear interior?
12) Is the equipment located above potential flood levels? Are housekeeping pads provided to keep spillage or leakage of water on the floor and out of the equipment?
13) Are there protective guards or covers on operator controls that can cause outages if bumped or brushed against such as trip switches and emergency power off (EPO) buttons?
14) Are there burnt-out or otherwise inoperative indicator lights on circuit breakers or relay and control panels?
15) Are there relays with targets that have not been reset from past tripping events?
16) Are there ground fault indicators provided on ungrounded systems? Do they show any uncleared faults? Are they remotely monitored?
17) Is metering provided on critical equipment? Is it remotely monitored?
18) Are there provisions for monitoring control and protection circuits and switchgear power supplies to detect conditions such as internal failure or loss of power supply?
19) Is equipment clearly labeled, following a consistent identification scheme? Is labeling up-to-date or are breakers that are in service still labeled “spare” and breakers that are off still labeled with a load designation?
20) Are mimic buses provided on switchgear, switchboards, and control panels?
21) Does the installation readily accommodate maintenance procedures by providing such features as generous working clearances, good light levels, provisions for application of protective grounds, hinged vs. bolted access panels, safe access to bolted bus and cable connections for thermography, etc.?

4.7 Operations and maintenance

The final area to be considered in the evaluation is O&M practices. We mentioned earlier that an effective PPM program is important to achieving the designed-in reliability of critical power systems, but this is only one of many aspects of O&M that can impact reliability. Other considerations include commissioning, training, documentation, and spare parts stocking. If an assessment of current O&M practices finds any of these areas lacking, the impact on reliability should be considered and improvements made. The greatest challenge in this area in most facilities is maintaining a long-term commitment to effective O&M practice in the face of short-term production schedules, cost control measures, and other management pressures.

4.7.1 Commissioning

Effective commissioning of power distribution systems and equipment is critical to achieving reliable performance. Commissioning provides an organized and documented process to verify proper installation, electrical integrity, and functional performance in accordance with the manufacturer's specifications and the design intent. This includes basic equipment acceptance tests such as relay testing, insulation resistance measurement, over-potential withstand, and contact resistance measurement, but should extend to step-by-step verification of control system operation, and system-level functional testing. It is also important that a similar process be in place for commissioning additions and modifications to the system, and recommissioning any control or protection systems that may be affected by the change. An example of this would be the need to retest a bus differential relay circuit when additional cubicles are added to the switchgear.

4.7.2 Training

The level of training and degree of knowledge of the system on the part of the personnel who are called on to operate and maintain it should be reviewed. Human activity is often claimed to be a factor in more than half of all failures of critical power systems and training may the most effective tool available to reduce outages. When new systems and equipment are installed, operators should be provided with training, not only from the manufacturer on the equipment itself, but from the designer or the plant engineer on the overall operation of the system and how the individual pieces of equipment function within it. Written system descriptions and operating procedures should be developed and used as the basis for both initial training and periodic retraining. While it is common to provide some operator training in the form of a "walk-through" and demonstration conducted by the installing contractor, a comprehensive program that includes both classroom and field training components is recommended. It is increasingly common to videotape or otherwise record initial training sessions to assist in training new employees and retraining existing staff.

4.7.3 System documentation

Accurate and up-to-date system documentation is another aspect of O&M practice that can significantly impact system reliability. The development of an up-to-date one-line diagram was discussed previously, but maintaining other items of system documentation are also important.

Accurate one-line diagrams and relay schedules are necessary to assess the extent of the system affected by an outage and to select appropriate switching procedures for restoration of service. All non-emergency switching of the system should follow written switching procedures to minimize the likelihood of errors that result in loss of load.

Preparing commonly used switching procedures in advance, such as a clearance procedure for each feeder in the system, can speed operator response and reduce outage durations.

Schematic and wiring diagrams and manufacturer's instruction manuals for all equipment should also be kept up-to-date and maintained either at the equipment location, or in a readily accessible and effectively indexed central filing system. This will reduce repair times and decrease the probability of increasing the extent of an outage through inadvertent action by maintenance staff.

The most useful documentation is accurate, concise, and located where it is needed during switching procedures or response to unplanned outages. Some measures that can be taken to reduce outages associated with human activity include the following:

a) Post one-line diagrams and operating procedures at the locations of switchgear and control panels.
b) Make sure that labels on equipment correspond to designations on the drawings.
c) Provide clear warning labels on control devices whose operation affects critical loads.
d) Post names and contact numbers for supervisors, engineering staff, utility dispatchers and emergency services in all electrical rooms and provide telephones, radios, or other means for rapid communication.
e) Use colors on drawings, mimic buses, and labels to distinguish between different systems and circuits.

4.7.4 Spare parts levels

A review of spare parts stocking levels for critical equipment can help assure higher reliability levels associated with short duration "replace with spare" outage times, in lieu of much longer "repair in place" outages.

For example, a conveyer system with large rollers may have one motor for each roller, or several hundred motors. The failure rate is 0.0109 per unit year for the motors, or 2 motor failures can be expected annually for a plant with 200 motors. The typical downtime is 65 h, but could be less for this specific example. In this case, there should be a means of separating the motor from the systems and allowing the conveyer system to continue operation, possibly by allowing the roller to idle until the end of a shift. Several spare motors should be available to minimize downtime.

Most plants have a population of motors large enough to expect several failures per year. The large variety usually precludes the maintenance of a spare motor stock, although availability should be checked with local distributors. Highly critical nonstandard equipment may require spares. However, each component of the electric system should be viewed in its relationship to the critical process and downtime. The value of carrying spare parts should be carefully weighed when long process interruptions could result from a single component failure.The cost of carrying spares for critical long repair time items, such as large motors, may be prohibitive; in such cases careful advance planning for repairs including assembling equipment data, planning rigging arrangements, etc., may significantly shorten repair times.

The cost of carrying spaces for critical, long repair-time items, such as large motors, may be prohibitive; in such cases, careful advance planning for repairs including assembling equipment data, planning rigging arrangements, etc., may significantly shorten repair times.

4.8 Other vulnerable areas

In many plants, the major process is controlled by a small component. This component may be a rectifier system, a computer, or a control system. The continuity of the electric supply to this controller is just as important to the process as the main machine itself. By proper application of energy storage within the device, usually large banks of capacitors, or external uninterruptible power sources, the controls can cause the equipment to go into a “safe-hold” position if the power source is interrupted. This continuity is important to note when thousands of dollars worth of products are being machined in one operation, such as in the aircraft industry. Computers or processors with dual-corded or triple-corded power supplies may also be considered to increase the reliability.

The accuracy and efficacy of a computer or a computer-based process is directly related to the “quality” of its environment. This quality is determined by more than just the continuity of the electric supply. Voltage dips, line noise, ineffective grounding, extraneous electrical and magnetic fields, temperature changes, and even excessively high humidity can adversely affect the accuracy of a computer or microprocessor. To minimize the probability of errors, the computer equipment should be properly shielded and grounded. It may even be beneficial to install a continuous uninterruptible power supply (UPS) or transient suppressor equipment on computer circuits where the controlled process is critical.

Testing facilities should have a backup power supply where interruptions could abort long-term testing. It is important to note that only sufficient power need be supplied to operate the test itself.

Another area of importance is the lighting required for safe operation of the machines. A failure in a particular lighting circuit may reduce the area lighting to a level below what is necessary to maintain a safe watch over production. Two means of overcoming this vulnerability are as follows:

a) Emergency task lighting
b) Sufficient lighting such that a single circuit outage does not reduce lighting to an unacceptable level

Another important lighting consideration is the fact that some metal halide lights [high-intensity discharge (HID)] require as long as 15 min to restart after being extinguished. Since even minor voltage sags that may go “unnoticed” by production equipment can extinguish this type of lighting, a supplementary source is necessary when the HID lamps are the primary source of illumination.

Air, oil, and water systems are frequently important auxiliary inputs upon which production depends. A compressor outage can, for example, cause significant production loss. While failures in these systems are usually mechanical in nature, electrical failures are not uncommon. Pumps are often integral parts of the cooling system in large transformers or even in rectifier circuits, and loss of coolant circulation could either shut down the equipment or significantly reduce production output. Therefore, pumps should be well maintained both mechanically and electrically when they comprise a significant part of the system, and spare parts may be a wise investment. Ventilation can also be critical to cooling, and ventilator fans are often neglected—until they fail. Hence, periodic maintenance and/or spare ventilator motors may be a good investment.

Some plants rely on a single feeder to supply their entire electrical requirements, and many plants rely on single feeders for major blocks of load. In these cases, it may be prudent to take several precautionary steps. One possible step would be the periodic testing of cables (see Lee [B1]). Another measure would be the use of spare cables or the storage of a single "portable" cable with permanently made ends and provisions for installing the portable cable at the various cable terminations in the plant distribution system. Lastly, *advance* documented arrangements could be made with a local contractor or the local utility for use of their portable cables and/or transformers on an emergency basis.

Premature equipment failure can result from electrical potential that is either too high, too low, excessively harmonic laden, or unbalanced, or any combination of these. Voltage tolerances are fairly well established by NEMA and ANSI. However, in Linders [B2], a means is provided to evaluate a situation where more than one area deviates from rating.

It is important to record and log voltage levels of all three phases at various strategic points on a periodic basis and to also determine the harmonic content in the plant's distribution system. The widespread use of solid-state switching devices has caused an increase in harmonic content in plant power, and it is often considered that such nonlinear loads must approach 20% of the plant load before detrimental effects are likely. However, the engineer must look at harmonic content in conjunction with other criteria to determine whether there is cause for a significant loss of life in his or her equipment. Filter circuits are generally used to remove harmful harmonics, and their nature is beyond the scope of this recommended practice. Fluorescent lighting also produces harmonics, but these harmonics are "blocked" by the use of delta–wye transformers.

4.9 Conclusion

The facility engineer should analyze the power distribution system electrically and physically and inquire about the utility's system. In this analysis, the engineer should

a) See that faults are properly isolated and that critical loads are not vulnerable to interruption or delayed repair.

b) Analyze the critical areas and evaluate the need for special restoration equipment, spare parts, or procedures.

c) Based on probability and economic analysis, make capital or preventive maintenance investments as indicated by the analysis.
d) Make carefully documented contingency plans.
e) Check the quality of the power supply from the utility and throughout the plant to determine if the equipment is vulnerable to premature failure.
f) Develop preventive maintenance, checking, and logging procedures to ensure continuous optimum reliability performance of the plant.

4.10 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 141, IEEE Recommended Practice for Electric Power Distribution for Industrial Plants *(IEEE Red Book).*[3, 4]

IEEE Std 242, IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems *(IEEE Buff Book).*

IEEE Std 315, IEEE Standard Graphic Symbols for Electrical and Electronics Diagrams.

IEEE Committee Report, "Report on Reliability Survey of Industrial Plants," Parts I–VI, *IEEE Transactions on Industry Applications,* vol. IA-10, March/April, pp. 213–252, July/August, pp. 456–476, September/October 1974, p. 681. (See Annex A and Annex B.)

4.11 Bibliography

[B1] Lee, R., "New Developments in Cable System Testing," *IEEE Transactions on Industry Applications*, vol. IA-13, May/June 1977.

[B2] Linders, J. R., "Effects of Power Supply Variations on AC Motor Characteristics," *IEEE Transactions on Industry Applications*, vol. IA-8, July/August 1972, pp. 383–400.

[B3] NFPA 70B-2006, Recommended Practice for Electrical Equipment Maintenance.[5]

[B4] NETA Acceptance Testing Specifications, 2003. InterNational Electrical Testing Association, Portage, MI.[6]

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[3] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

[4] The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

[5] NFPA publications are available from Publications Sales, National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101, USA (http://www.nfpa.org/).

[6] NETA publications are available at www.netaworld.org.

Chapter 5
Preventive maintenance

5.1 Introduction[a]

The objective of this chapter is to illustrate the important role maintenance plays in the availability of systems in industrial plants and commercial buildings. Details of "when," "how," and "how often" can be obtained from other sources (see Curdts [B2], Department of Army Maintenance Technical Manual [B4], "Factory Mutual Systems Transformer Bulletin" [B7], Hubert [B9], IEEE Committee Report [B15], "Maintenance Hints" [B17], NFPA 70B-2002 [B16], Miller [B18], Shaw [B19], Smeaton [B20]).[1]

Of the many factors involved in availability, preventive maintenance often receives meager emphasis in the design phase and operation of distribution systems when it can be a key factor in high availability. Large expenditures for systems are made to provide the desired reliability; however, failure to provide timely, high-quality preventive maintenance leads to system or component malfunction or failure and prevents obtaining the intended design goal.

Experience indicates that equipment lasts longer and performs better when covered under a preventive maintenance program. An effective preventive maintenance program can reduce accidents and operator error, and minimize costly breakdowns and unscheduled outages by identifying and solving problems early, before they become major problems.

5.2 Relationship of maintenance practice and equipment failure

The Reliability Subcommittee of the IEEE Industrial and Commercial Power Systems Committee published the results of a survey that included the effect of maintenance quality on the reliability of electrical equipment in industrial plants (see IEEE Committee Report [B15]). Each participant in the survey was asked to give his or her opinion of the maintenance quality in the plant. A major portion of the electrical equipment covered in the survey had a maintenance quality that was classed as "excellent" or "fair." Interestingly, maintenance quality had a significant effect on the percentage of all failures blamed on "inadequate maintenance."

As shown in Table 5-1, of the 1469 failures reported from all causes, inadequate maintenance was blamed for 240, or 16.4% of all the failures.

The IEEE data also showed that "months since maintenance" is an important parameter when analyzing failure data of electrical equipment. Table 5-2 shows data of failures caused by inadequate maintenance for circuit breakers, motors, open wire, transformers, and all equipment classes combines. The percent of failures blamed on inadequate maintenance shows a close correlation with "failure, months since maintained."

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[1] The numbers in brackets correspond to those of the bibliography in 5.9.

[a] Chapter 5 uses information from Department of the Army, TM 5-698-4, *Failure Modes and Effects Criticality Analysis for C4ISR Facilities,* 29 September 2006.

Table 5-1—Number of failures vs. maintenance quality for all equipment classes combined

Maintenance quality	Number of failures		Percent of failures due to inadequate maintenance (%)
	All causes	Inadequate maintenance	
Excellent	311	36	11.6
Fair	853	154	18.1
Poor	67	22	32.8
None	238	28	11.8
Total	1469	240	16.3

Table 5-2—Percentage of failure caused from inadequate maintenance vs. month since maintained

Failure (months since maintained)	All electrical equipment classes combined (%)	Circuit breakers (%)	Motors (%)	Open wire (%)	Trans-formers (%)
Less than 12 months ago	7.4	12.5[a]	8.8	0[a]	2.9[a]
12 to 24 months ago	11.2	19.2	8.8	22.2[a]	2.6[a]
More than 24 months ago	36.7	77.8	44.4	38.2	36.4
Total	16.4	20.8	15.8	30.6	11.1

[a] Small sample size; less than seven failures caused by inadequate maintenance.

From the IEEE data obtained, it was possible to calculate “failure rate multipliers” for transformers, circuit breakers, and motors based upon “maintenance quality.” These failure rate multipliers are shown in Table 5-3 and can be used to adjust the equipment failure rates shown in Chapter 10. “Perfect” maintenance quality has zero failures caused by inadequate maintenance.

Table 5-3—Equipment failure rate multipliers vs. maintenance quality

Maintenance quality	Transformers	Circuit breakers	Motors
Excellent	0.95	0.91	0.89
Fair	1.05	1.06	1.07
Poor	1.51	1.28	1.97
All	1.00	1.00	1.00
Perfect maintenance	0.89	0.79	0.84

5.3 Equipment preventive maintenance

5.3.1 Equipment deterioration

New equipment begins to deteriorate with installation. This is normal and if unchecked, the deterioration can progress and cause equipment malfunction or failure. Harsh environmental conditions and system stresses such as overload, severe duty cycle, load increases, circuit alterations, and changing voltage conditions can accelerate the deterioration process. An effective prevent maintenance program can detect and mitigate these conditions. Equipment preventive maintenance procedures should be developed to accomplish four basic functions: to keep the equipment clean, dry, and sealed tight, and to minimize the friction. Water, dust, high or low ambient temperature, high humidity, vibration, component quality, and countless other conditions can affect proper operation of equipment. Without an effective preventive maintenance program, the risk of a serious failure increases.

5.3.2 Causes of electrical failure

A common cause of electrical failure is dust and dirt accumulation and the presence of moisture. This can be in the form of lint, chemical dust, day-to-day accumulation of oil mist and dirt particles, etc. These deposits on the insulation, combined with oil and moisture, become conductors and are responsible for tracking and flashovers. Deposits of dirt can cause excessive heating and wear, and decrease apparatus life. Electrical apparatus should be operated in a dry atmosphere for best results, but this is often impossible; therefore, precautions should be established to minimize entrance of moisture. Moisture condensation in electrical apparatus can cause copper or aluminum oxidation and connection failure.

Loose connections are another cause of electrical failures. Electrical connections should be kept tight and dry. Creep or cold flow is a major cause of joint failure. Mounting hardware and other bolted parts should be checked during routine electrical equipment servicing.

Friction can affect the freedom of movement of devices and can result in serious failure or difficulty. Dirt on moving parts can cause sluggishness and improper electrical equipment operations such as arcing and burning. Checking the mechanical operation of devices and manually or electrically operating any device that seldom operates should be standard practice.

5.3.3 Preventive maintenance program

Procedures and practices should be initiated to substantiate that electrical equipment is kept clean, dry, sealed tight, and with minimal friction by visual inspection, exercising, and proof testing. Electrical preventive maintenance should be accomplished on a regularly scheduled basis as determined by inspection experience and analysis of any failures that occur.

A preventive maintenance program certainly will not eliminate all failures, but it will minimize their occurrence. Some of the key elements in establishing a program are as follows:

a) A physical equipment condition survey needs to be completed to evaluate the condition of the equipment and that it is operating with its rating. After collecting the system condition data, the equipment condition can be evaluated, which may reveal immediate repairs as well as the frequency of required inspections and tests. A preventive maintenance schedule of inspection and testing can be created specifically tailored to the operation, meeting the needs of both maintenance and production personnel.

b) Establish an “equipment service library” consisting of bulletins, manuals, schematics, parts lists, failure analysis reports, one-line diagrams, layout diagrams, equipment location/layout plans, cable maps, raceway layouts, etc. The bulletins and manuals are normally provided by the equipment manufacturer. Often they are not taken very seriously after equipment installation and are lost, misplaced, or discarded. It is important to remember that this documentation is vital to develop preventive maintenance procedures and to aid in training.

c) In addition to this documentation, each in-service failure should be thoroughly investigated and the cause determined and documented. Generally, it will be found that timely and adequate preventive maintenance could have prevented the failure. If correctable by preventive maintenance, the corrective action should be included on the work list and incorporated into the master preventive maintenance schedule. If the failure was caused by a weak component, then all identical equipment should be modified as soon as possible. “Failure analysis” plays a major part in a preventive maintenance program.

d) Provide the training necessary to accomplish the program that has been established. The techniques utilized in performance of a preventive maintenance program are extremely important. The success or failure of it relies on the qualifications and know-how of the personnel performing the work; therefore, training in preventive maintenance techniques is a major objective. Servicing of equipment requires better-than-average skills and special training. Properly trained and adequately equipped maintenance personnel must have a very thorough knowledge of the equipment operation. They must be able to make a thorough inspection and also accomplish repairs. For example, special training in the use of the dc high-potential dielectric tests or megger tests as well as the interpretation of the results may be required. Accurate analysis and interpretation of inspection and test results leading to follow through repairs, adjustments, or replacements is the purpose of an effective equipment preventive maintenance program.

e) A good record system should be developed that will show the repairs required by equipment over a long period of time. On each regular inspection, variations from normal conditions should be noted. The frequency and magnitude of the work should then be increased or decreased according to an analysis of the data. Avoid performing too much maintenance work as this can contribute to failures. The records should reflect availability of spare parts, service attitude of equipment manufacturers, major equipment failures to date, and time required for repairs, etc. These records are not only useful in planning and scheduling preventive maintenance work, they are also useful in evaluating equipment performance for future purchases.

f) Maintaining an adequate critical spare part inventory based on manufacturers recommendation and site specific maintenance trends is important to limiting downtime due to waiting for parts delivery. Maintaining OEM manuals are vital to a successful preventive maintenance program.

g) Maintaining accurate one-line diagrams and keeping system performance and protective studies (load flow, short circuit relay coordination, etc.) up-to-date as the electrical distribution system changes is very important to the electrical preventive maintenance program. Failure to calibrate or update system protective settings can cause catastrophic system failures that could have been avoided with proper proactive preventive maintenance.

5.4 Design for preventive maintenance

Preventive maintenance should be a prime consideration for any new equipment installation. Effective preventive maintenance begins with good design with a conscious effort toward maintainability. Quality, installation, configuration, and application are fundamental prerequisites in attaining a satisfactory preventive maintenance program. Installation cost without regard for performing efficient and economic maintenance influences system design. In many instances the additional cost of performing maintenance plus lost production from outages due to lack of maintenance more than offsets the savings in initial cost. A system that is not adequately engineered, designed, and constructed will not provide reliable service, regardless of how good or how much preventive maintenance is accomplished.

5.4.1 Quality and installation of equipment

One of the first requirements in establishing a satisfactory and effective preventive maintenance program is to have good quality equipment that is properly installed. Examples of this are as follows:

a) Large exterior bolted covers on switchgear or large motor terminal compartments are not conducive to routine electrical preventive maintenance inspections, cleaning, and testing. Hinged and gasketed doors with a three-point locking system would be much more satisfactory.

b) Space heater installation in switchgear or an electric motor is a vital necessity in high humidity areas; this reduces condensation on critical insulation components. The installation of ammeters in the heater circuit is an added tool for operating or maintenance personnel to monitor their operation.

c) Motor insulation temperatures can be monitored by use of resistance temperature detectors, which provide an alarm indication at a selected temperature (depending on the insulation class). Such monitoring indicates that the motor is dirty and/or air passages are plugged.

d) Standardization of installed equipment enables site personnel to maintain single manufacturers equipment such as diesel generators, switchgear, or circuit breakers instead of several different vendors. This also reduces spare parts inventory, tools, test equipment, and personnel training.

5.4.2 Installation of alternate equipment

The distribution system configuration and features should be such that maintenance work is permitted without load interruption or with only minimal loss of availability. Often, equipment preventive maintenance is not done or is deferred because load interruption is required to a critical load or to a portion of the distribution system. This may require the installation of alternate equipment and circuits to permit routine or emergency maintenance on one circuit while the other one supplies the critical load that cannot be shutdown. Examples are as follows:

a) Dual circuits to critical equipment
b) Double ended substations
c) Tie breakers
d) Drawout circuit breakers
e) Auxiliary power sources
f) Redundant utility feeds
g) Redundant on-site generators

Equipment that is improperly applied will not give reliable service regardless of how good or how much preventive maintenance is accomplished. The most reasonably accepted measure is to make a corrective modification.

5.5 Reliability centered maintenance

Reliability centered maintenance (RCM) is a logical, structured framework for determining the optimum mix of maintenance activities needed to sustain the operational reliability of systems and equipment while ensuring their safe and economical operation and support. RCM focuses on identifying preventive maintenance actions, but these actions can become corrective actions by default. That is, when no preventive action is effective or beneficial for a given item, then that item is run to failure (assuming safety is not at issue). RCM is focused on improving readiness, availability, and mission continuity through effective and economical maintenance.

5.5.1 RCM approach

Before RCM, everyone believed that everything had a “right” time for some form of preventive maintenance. This usually resulted in component replacement or system overhaul. Many maintenance and engineering personnel believed that replacing parts or performing a system overhaul would reduce the frequency of operational failures. Despite this view, the available data told a different story. In many instances, preventive maintenance seemed to have no beneficial impacts, and in many cases, preventive maintenance results in more problems by providing opportunity for maintenance-induced failures and mistakes.

a) As the airline industry in the U.S. observed that preventive maintenance did not always reduce the probability of failure and that some items did not seem to benefit from preventive maintenance at all, they formed a task force with the Federal Aviation Administration (FAA) to study the subject of preventive maintenance. The results of the study confirmed that preventive maintenance was only effective for items with certain failure patterns. Also concluded was that preventive maintenance is required only when necessary to assure safe operation. Otherwise, the decision to do or not do preventive maintenance should be based on economics.

b) The RCM approach provides a logical way of determining if preventive maintenance is appropriate for a given component. If action is required, the next step is to select the appropriate type of preventive maintenance. The RCM approach is based on the following guidelines:

    1) The purpose of preventive maintenance is to maintain an item’s full function(s). RCM attempts to maintain equipment function to keep the system operational, not just keeping components functioning. Specific redundancy may improve system reliability, but does increase capital and life-cycle costs.

    2) RCM emphasizes the total system end to end. RCM concentrates on maintaining total system and process function, not individual component function.

    3) RCM maintains reliability as the basis for decisions. The component failure characteristics must be known in order to evaluate the value in performing preventive maintenance. RCM takes into account not only simple failure rates, but also attempts to include the conditional probability associated with equipment age (failure probability for a given operating age bracket).

    4) RCM is directed by safety first, then economics. Safety must be the primary concern of any maintenance program. When determined that safety is not a factor, then preventive maintenance is justified on economic grounds.

    5) RCM recognizes the reliability limitations inherent in the design. Preventive and corrective maintenance cannot improve the inherent reliability built into the component; it is predetermined by its design. Preventive maintenance only hopes to maintain the component reliability inherent in the design of the component life.

6) RCM is a learning and evolving process. The difference between the perceived and actual design life and failure characteristics is addressed through age (or life) exploration.

c) The RCM concept is changing the way preventive maintenance is regarded. Wide acceptance exists that not all components benefit from preventive maintenance. Even when preventive maintenance would be effective, provided safety is not compromised; it is often less expensive to allow an item to "run to failure" rather than to do preventive maintenance.

While RCM originated to maintain safety and reduce preventive maintenance costs for the airline industry, other industries have embraced RCM. RCM is used to develop preventive maintenance programs for utility, nuclear, processing, and manufacturing plants. It is recognized that RCM is becoming a favored method for evaluating and developing a comprehensive maintenance program, due to the merging of the idea to improve system availability blended with the fiscal economic responsibility.

5.6 Relationship of RCM to other disciplines

Much of the analysis needed for reliability provides inputs necessary for performing an RCM analysis. The fundamental requirement of the RCM approach is to understand the failure characteristics of an item. As used herein, failure characteristics include the underlying probability density function (PDF), the consequences of failure, and whether or not the failure manifests itself and, if it does, how. Reliability is measured in different ways, depending on one's perspective: inherent reliability, operational reliability, mission (or functional) reliability, and basic (or logistics) reliability. RCM is related to operational reliability.

a) Inherent vs. operational reliability. From a designer's perspective, reliability is measured by "counting" only those failures that are design related. When measured in this way, reliability is referred to as *inherent reliability*. From a user's or operator's perspective, all events that cause the system to stop performing its intended function are failure events. These events certainly include all design-related failures that affect the systems' function. Also included are maintenance-induced failures, no-defect found events, and other anomalies that may have been outside the designer's contractual responsibility or technical control. This type of reliability is called *operational reliability.*

b) Mission or functional reliability vs. basic or logistics reliability. Any failure that causes the product to fail to perform its function or mission is counted in *mission reliability*. Redundancy improves mission reliability. Consider a case where one part of a product has two elements in parallel where only one is needed (redundant). If a failure of one element of the redundant part of the product fails, the other continues to function allowing the product to do its job. Only if both elements fail will a mission failure occur. In "basic" reliability, all failures are counted, whether or not a mission or functional failure has occurred. This measure of reliability reflects the total demand that will eventually be placed on maintenance and logistics.

One RCM precept is that safety must always be preserved. Given that the RCM concept came out of the airline industry, this emphasis on ensuring safety should come as no surprise. RCM specifically addresses safety and is intended to ensure that safety is never compromised. In the past several years, environmental concerns and issues involving regulatory bodies have been accorded an importance in the RCM approach for some items that is equal (or nearly so) to safety. Failures of an item that can cause damage to the environment or that result in some Federal or state law being violated can pose serious consequences for the operator of the item. So the RCM logic is often modified, as it is in this text, to specifically address environmental or other concerns.

System maintainability is essential to a successful RCM program. RCM is a method for prescribing preventive maintenance that is effective and economical. Whether or not a given preventive maintenance task is effective depends on the reliability characteristics of the item in question. Whether or not a task is economical depends on many factors, including how easily the preventive maintenance tasks can be performed. Ease of maintenance, corrective or preventive, is a function of how well the system has been designed to be maintainable. This aspect of design is called *maintainability.* Providing ease of access, placing items requiring preventive maintenance where they can be easily removed, providing means of inspection, designing to reduce the possibility of maintenance-induced failures, and other design criteria determine the maintainability of a system.

5.7 RCM implementation plan

The RCM process starts in the design phase and continues for the life of the system as shown in Figure 5-1; several major tasks are required to implement the RCM concept. Tasks include:

a) *Conduct supporting analyses.* RCM is a relatively information-intensive process. To provide the information needed to conduct the RCM analysis, several supporting analyses are either required, often as prerequisites to beginning the RCM analysis, or desirable. These supporting analyses include the failure modes and effects analysis (FMEA), fault tree analysis, functional analysis, and others.

b) *Conduct the RCM analysis*. The RCM analysis consists of using a logic tree to identify effective, economical, and, when safety is concerned, required preventive maintenance. (As will be seen, preventive maintenance is required when safety is involved; if no preventive maintenance is effective, then redesign is mandatory.)

Planning to implement an RCM approach to defining the preventive maintenance for a system or product must address each of the tasks noted in the preceding paragraph. The plan must address the supporting design phase analyses needed to conduct an RCM analysis. Based on the analysis, an initial maintenance plan, consisting of the identified preventive maintenance with all other maintenance being corrective, by default, is developed. This initial plan should be updated through life exploration during which initial analytical results concerning frequency of failure occurrence, effects of failure, costs of repair, etc., are modified based on actual operating and maintenance experience. Thus, the RCM process is iterative, with field experience being used to improve upon analytical projections.

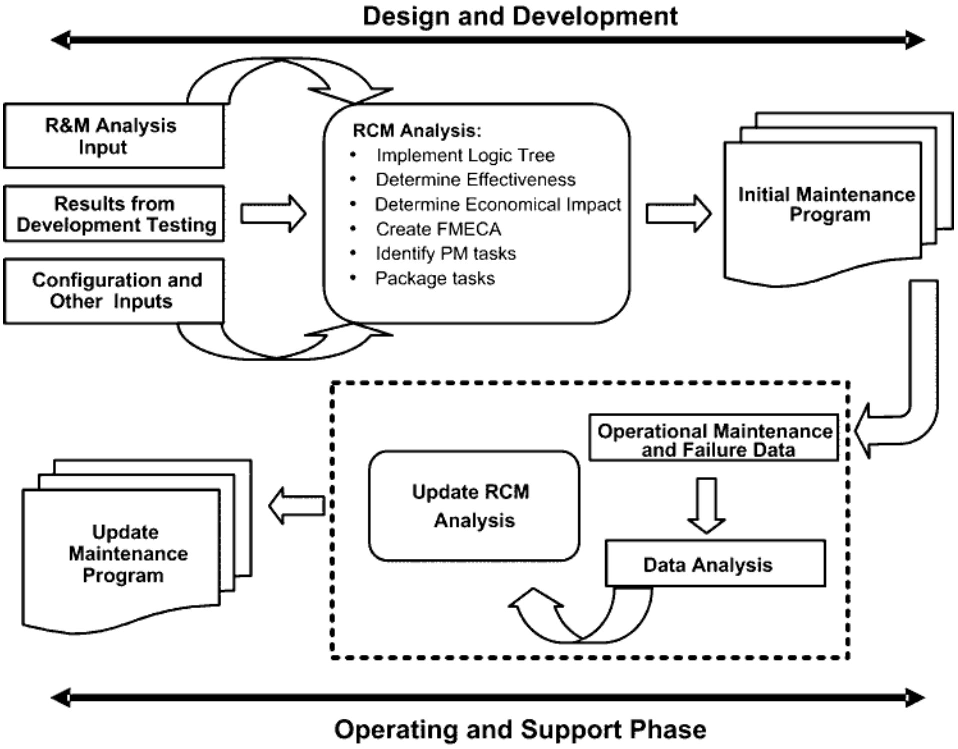

Figure 5-1—An overview of steps of the RCM process

5.8 Data collection requirements

5.8.1 Data categories

Since conducting an RCM analysis requires an extensive amount of information, and much of this information is not available early in the design phase, RCM analysis for a new product cannot be completed until just prior to production. The data falls into four categories: failure characteristics, failure effects, costs, and maintenance capabilities and procedures.

a) *Failure characteristics*. Studies conducted by the FAA and confirmed by later studies showed that preventive maintenance was effective only for certain underlying probability distributions. Components and items, for example, for which a constant failure rate applies (e.g., the underlying probability distribution is the exponential) do not benefit from preventive maintenance. Only when there is an increasing probability of failure should preventive maintenance be considered. Note that many components or systems are modeled with a constant failure rate, but in actuality most exhibit wearout characteristics, which require preventive maintenance. This is why RCM is performed on components by failure mode.

b) *Failure effects*. The effects of failure of some items are minor or even insignificant. The decision whether or not to use preventive maintenance for such items is based purely on costs. If it is less expensive to allow the item to fail (and then perform corrective maintenance) than to perform preventive maintenance, the item is allowed to fail. As stated earlier, allowing an item to fail is called *run to failure*.

c) *Costs*. The costs that must be considered are the costs of performing a preventive maintenance task(s) for a given item, the cost of performing corrective maintenance for that item, and the economic penalties, if any, when an operational failure occurs.

d) *Maintenance capabilities and procedures*. Before selecting certain maintenance tasks, the analyst needs to understand what the capabilities are, or are planned, for the system. In other words, what is or will be the available skill levels, what maintenance tools are available or are planned, and what are the diagnostics being designed into or for the system.

5.8.2 Sources of data

Table 5-4 lists some of the sources of data for the RCM analysis. The data elements from the FMEA that are applicable to RCM analysis are highlighted in item b) of 5.5.1. Note that when RCM is being applied to a product already in use, historical maintenance and failure data will be inputs for the analysis. When historical data is not available or during the design phases of a system, generic data is an in valuable source for establishing a base line and making comparison analysis on the system. An effective failure reporting and corrective action system (FRACAS) is an invaluable source of data.

Table 5-4—Data sources for the RCM analysis

Data source	Comment
Lubrication requirements	Determined by designer. For off-the-shelf items being integrated into the product, lubrication requirements and instructions may be available.
Repair manuals	For off-the-shelf items being integrated into the product.
Engineering drawings	For new and off-the-shelf items being integrated into the product.
Repair parts lists	For off-the-shelf items being integrated into the product.
Quality deficiency reports	For off-the-shelf items being integrated into the product.
Other technical documentation	For new and off-the-shelf items being integrated into the product.
Recorded observations	From test of new items and field use of off-the-shelf items being integrated into the product.

Table 5-4—Data sources for the RCM analysis *(continued)*

Data source	Comment
Hardware block diagrams	For new and off-the-shelf items being integrated into the product.
Bill of materials	For new and off-the-shelf items being integrated into the product.
Functional block diagrams	For new and off-the-shelf items being integrated into the product.
Existing maintenance plans	For off-the-shelf items being integrated into the product. Also may be useful if the new product is a small evolutionary improvement of a previous product.
Maintenance technical orders/manuals	For off-the-shelf items being integrated into the product.
Discussions with maintenance personnel and field operators	For off-the-shelf items being integrated into the product. Also may be useful if the new product is a small evolutionary improvement of a previous product.
Results of FMEA, FTA, and other reliability analyses	For new and off-the-shelf items being integrated into the product. Results may not be readily available for the latter.
Results of maintenance task analysis	For new and off-the-shelf items being integrated into the product. Results may not be readily available for the latter.

5.8.3 Failure mode, effects, and criticality analysis

The failure mode, effects, and criticality analysis (FMECA) is a reliability evaluation and design technique that examines the potential failure modes within a system in order to determine the effects on the overall system and the equipment within the system. The FMECA is composed of two separate analyses: the FMEA and the criticality analysis (CA). The FMEA classifies each potential failure according to severity on the mission success and personnel/equipment safety. The CA will provide estimates of system critical failure rates based on past history and current information.

The FMECA should be initiated as soon as preliminary design information is available. The FMECA is a living document that is not only beneficial when used in the design phase but also during system use. As more information on the system is available, the analysis should be updated in order to provide the most benefit.

5.8.4 Maintenance data

Generic maintenance data is a valuable tool when historical information is not available or when the engineering is establishing a maintenance-based line for a new system. This type of data is extremely rare but important to the establishment of a good RCM program. The following information is presented to the analyst to assist in the development of maintenance approaches including RCM. The data is an excerpt of the data collection effort defined and presented in Chapter 10. Definitions and maintenance formulas can be found in that chapter. Maintenance information is presented for those items with eight or more failures as dictated by IEEE requirements. Maintenance data on the remaining components can be found in Annex Q.

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[3] The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

[B12] IEEE Std 95™-2002, IEEE Recommended Practice for Insulation Testing of AC Electric (2300 V and above) Machinery with High Direct Voltage.

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Chapter 6
Emergency and standby power

6.1 Introduction

Achieving the necessary degree of reliability in the power to utilization equipment that, for a variety of reasons, cannot tolerate outages and quality problems experienced with the normal power supply, often leads to application of emergency or standby power supplies**.** These power supplies can provide necessary acceptable power during the times the normal power supply is not acceptable or is not available.

Effects of outages and quality problems vary depending on the utilization equipment requirements. Tolerable outages may vary in duration from no more than a fraction of a cycle to times measured in hours. Frequency of outages that can be tolerated may vary from zero to several over a given time period. Equipment performing data processing, for example, might require a power supply that is theoretically conditioned, i.e., uninterruptible and free of voltage and frequency excursions. Loads such as emergency exit lighting and some other types of life safety related loads require restoration of power after an outage in no more than a few seconds. Applicable codes should be reviewed, especially regarding power to life safety equipment, to determine maximum outage times allowed. Some loads can tolerate outages for durations varying from times measured in minutes to times measured in hours, but still require restoration of power within a certain time to avoid eventual unacceptable conditions. Tolerated outage times will be facility specific and fully dependent on the type of load and the mission of the facility.

When the tolerable outage time, frequency of outages, and quality are identified, the need for and type of emergency or standby power supply can be identified. There are many ways to improve reliability and availability of a power supply, such as redundancy in utility power supply and facility distribution equipment, higher quality distribution equipment, "prime power" contracts with electric utilities that achieve a higher priority status, and more effective maintenance. Also, the manner in which power is supplied from the utility can make a difference in reliability. For example, whether power is delivered to the facility at transmission or distribution level, and whether power is delivered via overhead lines or underground duct bank can make a difference in reliability. Facility loads that are served at transmission level voltage tend to be more reliable than those served from distribution level voltage for several reasons. During utility outages, the transmission systems will be restored first and tend to have more redundancy built in to the topography than distribution systems. With regard to overhead or underground transmission or distribution lines, geographic location can also play a role in power reliability. For example, a facility being supplied by overhead distribution lines in a geographic location that is very windy or susceptible to heavy snow and ice storms may not be as reliable as an underground service in that same location. Application of on-site emergency or standby power is inevitably for the purpose of achieving maximum availability in power supply to the load. Additional information and details on emergency and standby power can be found in IEEE Std 446™ *(IEEE Orange Book™)*.[1]

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[1] Information on references can be found in 6.4.

6.2 Emergency and standby power supply types

6.2.1 Engine-driven generators

These types are available in sizes ranging from a few to several thousand kilowatts. Fuel types most common are diesel, natural gas, gasoline, and liquid petroleum gas. Diesel fueled engines are often more readily available and more economically priced in larger sizes for types designed for emergency or standby use. However, some manufacturers have now made larger natural gas-fueled units more readily available than in the past.

Engine speed designs are typically from about 1200 rpm to 1800 rpm, although some slower speed designs can be made available. These relatively high speeds make continuous round-the-clock operation impossible without considerable extra maintenance, supervision, and scheduled downtime with resulting higher costs. Prime (continuous) and standby ratings serve to show limits of maximum loading and heating that are intended only for short periods of time.

Engine generator sets designed for standby or emergency use are most commonly offered in complete self-contained packages that require little are no off-skid equipment, depending on size and operating conditions. An exception, for instance, would be a large unit that may require off-skid cooling equipment if a radiator attached to the engine or skid is not practical because of limited space or other restrictions. Depending on the fuel type and size of engine, and expected run times, off-skid fuel storage may be necessary. Another important consideration involves the inherent oil consumption of industrial type engines. It is sometimes desirable and practical, particularly on larger units, to provide a separate oil reservoir with automatic oil feed to the engine.

Engine-driven generators designed for emergency or standby use are typically fast starting and able to take load in 15 s or less. The amount of initial block loading an engine is capable of, without a detrimental effect on the life of the equipment, depends to a large extent on the temperature of lubricating oil and jacket cooling medium. On large units where investment is high, consideration should be given to application of heaters that keep jacket cooling medium and, consequently, lubricating oil within acceptable temperatures during periods of downtime.

6.2.2 Turbine-driven generators

Turbine-driven generators discussed here exclude steam turbines. Although there may be circumstances and scenarios where steam turbines could be applied for standby use, they are most commonly used for prime power applications. Gas or oil fired units are available in sizes from about 50 kW to several thousand kW. Fuel types available are similar to those listed in 6.2.1 for engines, although gasoline is less common. Turbines have an advantage over engines, being lighter in weight and less costly to install but are at a disadvantage in fuel efficiency if there is no heat recovery, and with larger units, usually take longer to start and load because of warm-up times required.

In applications requiring long periods of run time, such as several days, weeks, or longer, turbines are better suited than engines because of their simplicity and design for continuous use. They are also considered to require less supervision and maintenance while in use.

6.2.3 Transfer switching equipment

Emergency and standby generators are normally applied with switching equipment on their output to transfer loads from the normal power supply to the generator and back to the normal power supply when it is available and acceptable. In applications where codes require emergency power availability within a certain time, automatic transfer switching is applied. In the simple application of a single emergency or standby generator where automatic switching is desired, a single automatic transfer switch (ATS) is used. The ATS usually contains all controls necessary to sense loss of the normal supply, to start the emergency or standby generator, and transfer the power to the load from one source or the other, including all necessary time delays. Options such as minimum run-time control and periodic automatic exercising of the generator set are examples of controls that can also be included in the ATS package.

Reliability in emergency or standby power can be enhanced by application of more than one generator, especially where cost is not overly sacrificed and where the size and number of loads can be separated according their criticality.

The following figures illustrate examples of emergency or standby generators using ATSs.

Figure 6-1 shows two generators that will both start on loss of the normal source. The first to start up and achieve acceptable voltage and frequency is connected to the most critical load by the ATS and the less critical load is disconnected. When the second unit comes up to speed and voltage, it is synchronized to the first, and the less critical load is then reconnected. If one generator fails, it is immediately disconnected and the less critical load is again disconnected.

Depending on electric utility contracts and rates, operating in parallel with the utility for extended periods is sometimes economically advantageous to both the customer and the utility. High demand charges during certain periods are usually associated with limited capacity from the utility. Operating emergency or standby generation to serve a portion of the load with the utility serving the remainder, referred to as *peak shaving,* reduces the power demand from the utility by the amount of load on the generation. Energy from the utility is also reduced and, in some cases, also significantly contributes to savings. The cost of operation of generation must be less than the utility's demand and/or energy costs during these periods, sometimes called *peak periods*. Reliability of the generation is important since failure to start or failure while running can result in high demand charges that may affect future utility power costs for several months or even up to a year. Some emergency or standby type generation may not be suitable for long periods of run time without extra maintenance and supervision. High-speed engines could be a problem in this respect. This must be considered in the use of emergency or standby generation for peak shaving.

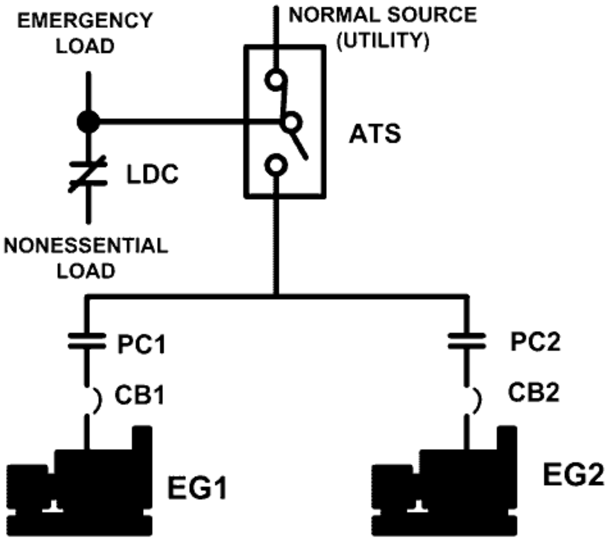

Figure 6-1—Two engine-generator sets operating in parallel

Figure 6-2 shows a peak shaving application making use of ATSs. In this scheme the generators are always isolated from the utility but the load must tolerate momentary outages when switching between sources. The second ATS allows the generators to run during peak periods to serve the loads designated for this use. All loads are still able to be served from the generation on loss of utility power.

Transfer switches may be open or closed transition type. Open transition switching means there is a complete break in power to the load during switching and the sources being switched are never connected together in parallel. In closed transition switching, one source is connected with the other source in parallel before the other source is disconnected, eliminating a momentary outage. Peak shaving applications and switching from emergency or standby generation to the normal source after it has been restored are cases where closed transition may be desired. The utility must agree with and approve this type of switching since there is momentary paralleling with the utility. Specific protective relaying must usually be applied and approved by the utility. This relaying is necessary to minimize the risk of damage to the generation equipment and prevent unwanted power flow into the utility system. IEEE Std 242™-2001 *(IEEE Buff Book™)* discusses control and protection schemes used when on-site generation is paralleled with an electric utility source.

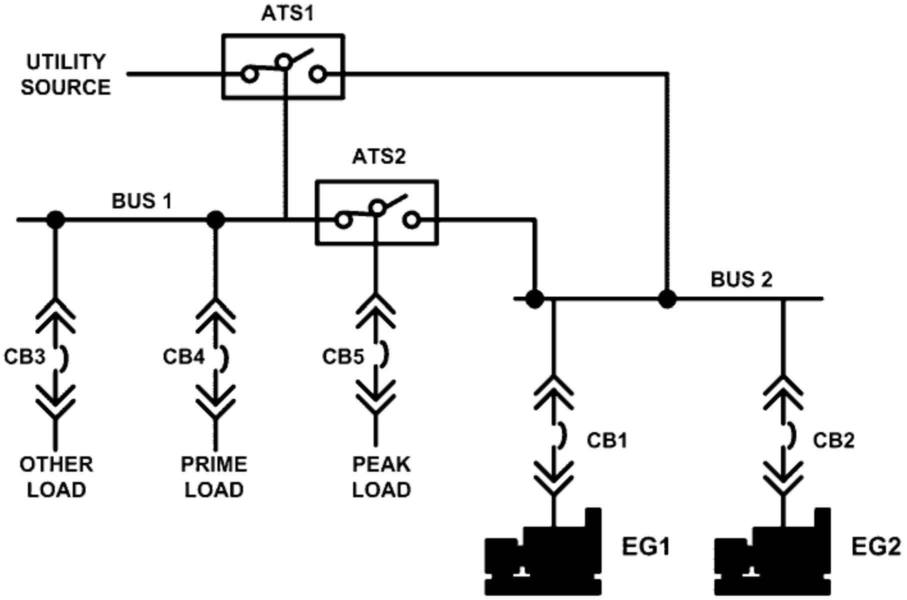

Figure 6-2—Dual engine-generator standby system

6.2.4 Starting equipment

A critical element in the reliability of an emergency or standby generator is its starter and/or controls and equipment associated with starting. Reliability surveys (see Annex L) have shown that a significant number of failures counted for these units are associated with failure to start.

Starters may be electric motors, air or gas motors, or engines of various fuel types. The type chosen should be conducive to the type of generator set and facilities in the plant or location. Electric dc motor starters, very typical on engine generator sets and small turbines, must include a battery and alternator or battery charger to maintain the battery in a charged state. Battery and charger or alternator sizes make this type of starting equipment very adaptive to the self-contained package concept. Many plants maintain air volumes for a variety of uses, making air starters on generator sets practical. The air must be at sufficient pressure to crank the engine or turbine and the available volume should be sufficient to allow several start attempts. A storage tank and one or more air compressors must be in place. Large turbines, such as sizes exceeding 1000 kW, may have diesel or gas engines as starters, and dc electric motors may sometimes use up to 1000 kW in size. Engine type starters must have a reliable fuel supply and a reliable starter of their own. Since gas turbines require a relatively high-pressure fuel source, a gas motor type starter is sometimes practical if the gas supply, before being regulated for fuel use, is of sufficient pressure.

6.2.5 Mechanical stored energy system

The most common type of system providing mechanical stored energy is the motor-generator (m-g) set. The basic components are an electric motor, either ac or dc, driving an ac generator. Backup power, or ride through time, is provided by the rotating inertia of the set during a short outage. However, if a stored energy device such as a battery is used as backup to the normal power supply to the motor, the system can justly be called an uninterruptible power supply (UPS).

The simplest systems provide ride-through times for power outages up to about 500 ms. Additional rotating inertia, such as in the form of a fly-wheel, can increase ride-through times by several seconds, often long enough for an additional standby source to come online.

There are many combinations of equipment that can be used to increase the reliability of power from an m-g set. IEEE Std 446 *(IEEE Orange Book)* discuss this subject in greater detail.

Figure 6-3 illustrates a simple m-g set designed to ride through momentary power outages. This system is not designed to provide backup power for extended periods. Figure 6-4 is a system designed to provide backup power for outages for as long as the battery capacity will allow. The reliability of power to the load is enhanced by the addition of bypass switching that may be automatic or manual.

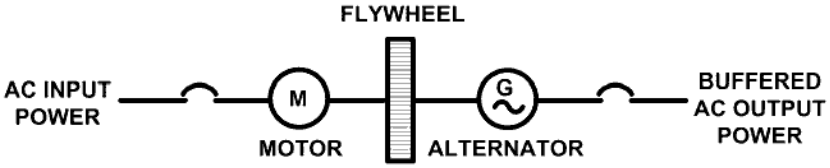

Figure 6-3—Simple inertia-driven “ride-through” system

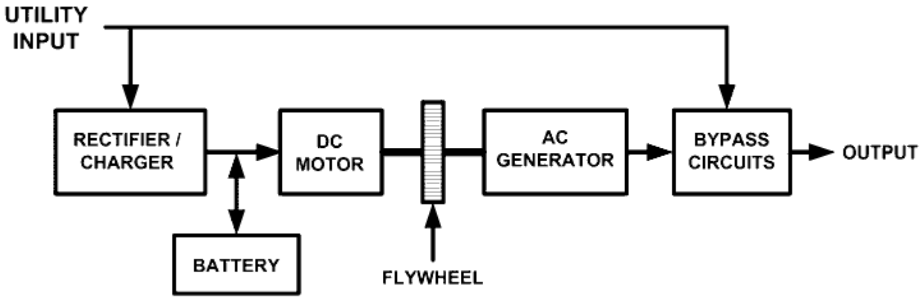

Figure 6-4—Battery/dc motor/ac generator

M-G sets have the advantage of truly isolating the load from the normal source as this may be desirable if surges, frequency excursions, or the like are a problem.

6.2.6 Battery systems

Batteries provide the source of power necessary for what the industry normally refers to as a *static UPS.* The common form of a static UPS is a battery system that includes equipment (rectifier/inverter) to provide dc to an inverter and a charging supply to the battery and a regulated ac output. Actually, the inverter is simply a dc load on the battery or rectifier. The battery capacity determines the length of time a power outage can be tolerated with certain load conditions. Capacities can vary from a few minutes to several hours depending on the size and type of battery used and the load profile.

Because battery chargers and inverters have finite lives, failures eventually occur. A good battery serves little purpose if the inverter has failed in an application where the inverter is the only dc load. UPS systems often include static transfer switches on the output to allow the load to be switched virtually transient free from the inverter to an alternate supply and vice versa. Typical static transfer switches can complete switching within 1/4 cycle, which for most equipment is equivalent to no break in power. Systems are designed to keep the inverter output in synchronism with the alternate supply, eliminating delay in transfer. Some systems are supplied that anticipate a failure of one supply, and transfer is actually with no break in power to the load. Static transfer switches can also fail. Maintenance bypass switches are available with circuitry to bypass all components of the UPS, usually done manually. They can be designed with switching to allow maintenance of the UPS components and also to allow testing of the components without disruption of power to the load. Today’s application engineer is faced with a growing challenge to supply certain critical loads with 24/7/365 reliable power, typically achieved by UPS systems. Temporarily removing critical load from a UPS output for UPS maintenance (i.e., switching the load to maintenance bypass) is becoming less acceptable, making it more and more difficult to achieve necessary preventive maintenance on the UPS equipment. Where maintenance bypass circuits are otherwise fed by a utility power source, enhanced reliability to critical loads can be achieved by serving the maintenance bypass circuit from a non-utility source such as another UPS system or an on-site generator set or a combination of both.

Redundancy of components is often applied to achieve a higher degree of reliability. There are many combinations of components possible, each having maintenance, operation, and cost advantages and disadvantages. IEEE Std 446 *(IEEE Orange Book)* provides more in depth discussion. Figure 6-5, Figure 6-6, and Figure 6-7 illustrate some examples.

Figure 6-5 shows the simplest form of a static UPS. Power to the load is derived from the normal supply through the charger and inverter and from the battery should the normal supply fail.

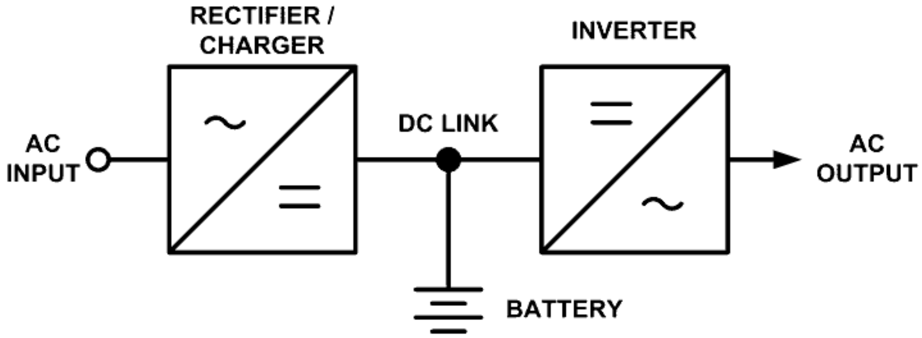

Figure 6-5—Single UPS unit with rectifier/charger

Figure 6-6 shows the basic system with the addition of a static transfer switch on the output. If the system is designed to normally supply the load from the inverter, the static transfer switch will transfer to the alternate supply on an inverter failure and then back to the inverter when its output is normal again. The reverse is true if the load is normally supplied from the alternate supply. This illustration shows a dc contactor that may or may not be desirable depending on the inverter design and whether this isolation is necessary. Allowing the static transfer switch to transfer from the inverter to the alternate supply when the inverter output fails, in some cases, is a deliberate design plan. An example would be when a large inrush is expected, such as a motor starting; the inverter, if not sized large enough, will go into current limiting and the static transfer will sense the reduced output and switch allowing the alternate source to supply the inrush. When the load has stabilized, the static transfer switch will transfer the load back to the inverter. This application also enhances reliability of power to ac loads when the loads are served by several branch circuits with proper overcurrent devices. A fault on a branch circuit can selectively clear if the alternate supply provides the fault current, thus maintaining power to remaining branch circuits.

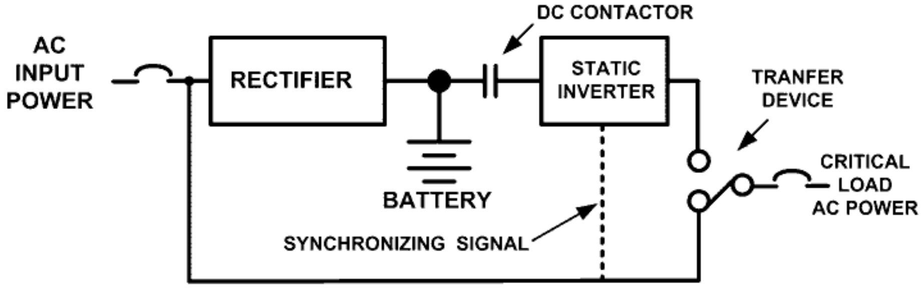

Figure 6-6—Single UPS unit with static transfer switch

Figure 6-7 shows an example of redundancy in UPS components in the form of a parallel UPS system, but using a single battery. Each UPS system would be designed to share load and sized such that one or more can be out of service without loss of capacity equal to the load. Usually some type of switching is necessary on the output of each inverter to isolate it and prevent affecting the other inverter(s) when it is out of service.

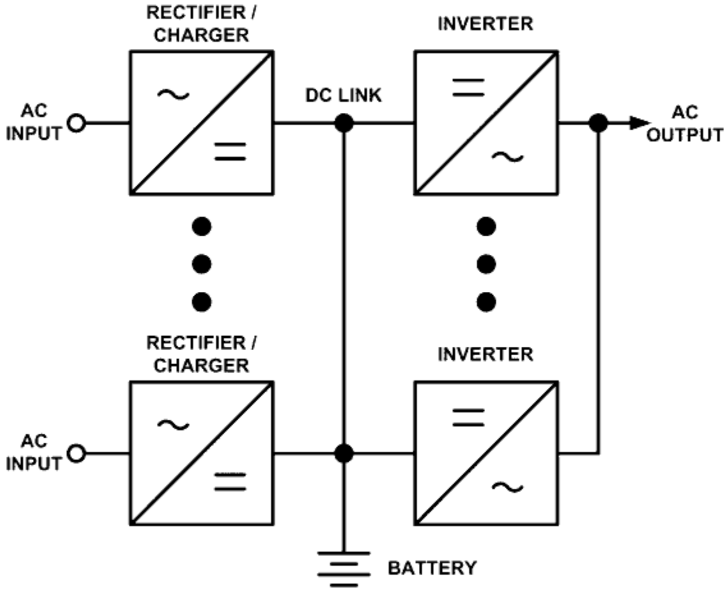

Figure 6-7—Parallel UPS with a single battery

Battery life, or the time when the battery can no longer be charged to sufficient capacity to adequately serve the load, is an important design and application criteria in the application of a UPS. There are many types of batteries available, each designed for specific purposes and types of loads. It is important that a battery supplier be given an accurate dc load profile, including the load amperes and time the battery is expected to supply the amperes and to what voltage the cells are allowed to discharge to (end voltage) so that the proper battery can be selected.

The ambient temperature that a battery is subjected to may be the most important factor affecting its life. Where ambient temperatures cannot be controlled, certain battery types are more suitable than others. Battery manufacturers should be consulted. The rectifier/ charger, which serves to provide dc to float and recharge and sometime equalize charge, should have an output of sufficient quality such that the battery life is not adversely affected. Excessive ac ripple can usually be corrected with filtering. The charge rate should be carefully set and monitored to assure that the battery manufacturer's recommendations are adhered to. This requires selecting the optimum number of cells for the battery so that equalize and charge voltages do not damage dc loads.

The rectifier/charger must be correctly sized to carry all continuous load and still be able to recharge a discharged battery within an acceptable time. The critical nature of loads and the reliability of the normal (alternate) power supply will greatly affect how fast a discharged battery must be recharged. Where the alternate power supply is extremely unreliable, the charger may have to be sized to recharge the battery within as short a time as 8 h. This, for practical purposes, would require twice the charging output current to recharge the battery in 16 h.

6.3 Conclusions

To determine the need for emergency and standby power, applicable codes and regulations must be researched and understood, requirements of the loads to be served must be evaluated and identified including the effects of loss of acceptable power, and the reliability and quality of the normal supply (i.e., electric utility source) must be known. Then the need, type, and arrangement of the emergency or standby power system can be accurately assessed.

The chapter has presented an overview of common types of emergency and standby power systems used by most industries to achieve increased reliability in power supply to loads. No attempt is made to list and describe every type of existing system that may be classified as an emergency or standby power system. For example, fuel cells continue to be developed and researched for a wide range of applications. At this time, however, most would agree their cost prohibits attractive practical use in general industrial and commercial applications for emergency and standby power.

6.4 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 446, IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications *(IEEE Orange Book).*[2]

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[2] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

Chapter 7
Voltage sag analysis

7.1 Introduction

Voltage sags, also referred to as *voltage dips,* are important to industrial reliability. Automated processes can be particularly susceptible to voltage sags. The combination of voltage sags and susceptible equipment may cause significant production outages and damage to both equipment and work in process. Less susceptible equipment or sag mitigation devices may be available, but the designer must know sag characteristics of the local electric system to make the best choices between process reliability and equipment cost. This chapter shows how to predict voltage sag performance of the electric supply system, if system characteristics are known, by analyzing reliability data. Voltage sag coordination charts are then developed to aid in predicting the number of utilization equipment shutdowns. Voltage sag monitoring surveys are also discussed. These methods and data are presented to aid in the assessment of equipment susceptibility to the locally typical voltage sag environment.

Voltage sags are very different from the electric service interruptions that are the main theme of other chapters of this recommended practice. A service interruption is caused by a complete separation of a load from the source of electric energy. A voltage sag is a sudden voltage drop while the load remains connected to the supply. Sags are usually caused by insulation failures or faults on power systems. Sags may also be caused by sudden load changes, such as starting large motors.

Utilization equipment can be very susceptible to voltage sags. There are reports that voltage sags to 85% to 90% of nominal with duration as short as 16 ms have triggered immediate outages of critical industrial processes. Equipment in this sensitivity range is likely to be upset by voltage sags on an order of magnitude more often than from interruptions. Production workers may notice the lights blink or dim just when the critical process fails. Many will incorrectly conclude the plant experienced an interruption instead of a voltage sag. Blinks from shallow sags can be imperceptible, and a resulting process line outage may be recorded as an "unknown process shutdown." The survey results shown in Table 7-1 reveal that, once an interruption has caused a process shutdown, the average time to restart that process is 1.39 h. The restart time for shutdowns caused by momentary voltage sags is often of the same order.

It is possible to design equipment that will survive even severe voltage sags, but the equipment may be more expensive. Accurate estimates of sag magnitude and duration probabilities help system designers to specify appropriate equipment for critical processes. This chapter shows how to combine accepted analysis tools to predict the important voltage sag characteristics. The basic tools include a computer program to calculate unbalanced fault currents and voltages, utility reliability data, and fault-clearing device characteristics (see Voltage Sag Working Group [B30]).[1]

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[1] The numbers in brackets correspond to those of the bibliography in 7.14.

Calculations can be performed by any of several good computer short-circuit analysis programs. These programs allow users to accurately model the electrical network, apply short circuits around the network, and look at the resulting voltage on any bus of interest. Some software producers have automated most of the steps for sag predictions. An alternative simpler predictive method is more suitable when the availability of system data is limited (see 7.6). Continuous monitoring of voltage is useful to calibrate the sag predictions and show the seasonal and yearly variations in voltage sag frequency that are common. These techniques allow engineers to anticipate and possibly minimize voltage sag problems.

The ability to predict voltage sag characteristics offers a unique opportunity to evaluate alternate power system configurations and prevent problems with optimum supply and ride-through specifications. Problems may be lessened by reducing voltage sag magnitude, duration, or the number of sag events. Changes in equipment specifications or addition of voltage sag correction devices also can significantly reduce the number of unplanned process outages from voltage sags.

7.1.1 What is an interruption?

From the standpoint of electric power service, an *interruption* is the reduction of load point voltage to less than 10% of the nominal rms magnitude (see IEEE Committee Report [B17]). Yet, critical production equipment may cease to operate normally—experience an *interruption* in production functionality—if load point voltage momentarily drops below even 80% to 85%.

Within the context of 3.2.2, evaluation of reliability begins with the establishment of an interruption definition. Such a definition specifies the magnitude of the voltage reduction and the minimum duration of the reduced-voltage period that result in a loss of production or other function for the plant, process, or building in question. Frequently, in this context, interruption definitions are given only in terms of a minimum duration and assume that the voltage is zero during that period.

IEEE surveys (see IEEE Committee Reports [B17], [B18], and Patton et al. [B25]) have revealed a wide variation in the minimum or critical service loss duration, i.e., the maximum length of time an interruption of electrical service will not stop plant production. Table 7-1 summarizes results for 55 industrial plants in the U.S. and Canada and Table 7-2 gives results for 54 commercial buildings. It is clear from these tables that careful attention must be paid to choosing the proper interruption definition in any specific reliability evaluation.

Table 7-1—Critical duration of service loss for industrial plants

25th percentile	Median	75th percentile	Average plant outage time for equipment failure between 1 and 10 cycle duration
10 cycles	10 s	15 min	1.39 h

Table 7-2—Critical duration of service loss for commercial buildings

Percentage of buildings with critical duration of service loss							
≤ 1 cycle	**≤ 2 cycles**	**≤ 8 cycles**	**≤ 1 s**	**≤ 5 min**	**≤ 30 min**	**≤ 1 h**	**≤ 12 h**
3%	6%	9%	15%	36%	64%	74%	100%

Another important consideration in the economic evaluation of reliability is the time required to restart a plant or process following a power interruption. A 1970s IEEE survey of 43 industrial plants in the U.S. and Canada (see IEEE Committee Report [B17] and see also Table 7-3) indicates that industrial plant restart time following a complete plant shutdown due to a power interruption averages 17.4 h. The median plant restart time was found to be 4.0 h. Clearly, specific data on plant or process restart time should be used if possible in any particular evaluation.

Table 7-3—Plant restart time after service is restored

Average (h)	Median (h)
17.4	4.0

Many industrial plants reported that 1 to 10 cycles were considered critical interruption time, as compared to 1.39 h, required for start-up (plant outage time being considered equal to plant start-up time). This indicates that the critical factor must be carefully explored prior to assigning a cost to the interruption. That only 15% of the commercial buildings reported the critical service loss duration time to be 1 s or less is probably attributable to the fact that computer installations were less common in the early 1970s than is the case today.

Further data from the IEEE Committee Report [B17] graphically illustrates the time required to start an industrial plant after an interruption. Thus, the first step of a reliability analysis of any system becomes the selection of the critical duration (time) of the outage and the plant start-up time, including equipment repair or replacement time required because of the interruption.

7.2 Voltage sag characteristics and reporting

Magnitude and duration are two very important sag characteristics. Sag magnitude is the net rms voltage in percent or per-unit of system nominal voltage. Sag magnitude is the *remaining* voltage. This sag magnitude definition matches the output of computer programs used to calculate sags. Sag duration is the time the voltage is low, usually less than 1 s.

The terminology used in this chapter follows the definitions of IEEE Std 1159™.[2] Whereas voltage *dip* definitions in some older IEC standards refer to a percent reduction, or what was lost, IEC 61000-4-30:2006 [B13] now defines the *dip magnitude* as the remaining voltage—the terms *sag* and *dip* are now interchangeable between IEEE and IEC standards.

According to IEEE 1159 classifications, sag magnitudes range from 10% to 90% of nominal voltage and sag durations from one half-cycle to 1 min (magnitudes less than 10% are classified as interruptions). The voltage sag coordination method described in this chapter works independently of these ranges. In fact, from an equipment or production process point of view, it is irrelevant whether a trip is due to a voltage sag, a momentary interruption, or a sustained interruption. IEC 61000-4-30:2006 [B13] defines a voltage sag as a temporary reduction of the voltage below a user-specified threshold and notes that temporary interruptions are a special case of a voltage sag.

A variety of definitions, classifications, indices, and reporting philosophies were under consideration as this chapter was being prepared. Work to standardize is in progress. Users may wish to review other standards developments for preferred methods to report results. The following discussion offers various methods that may apply to individual situations. It demonstrates the need for clarity in reporting results. It is highly recommended that reports of voltage sag predictions or results from power quality monitoring clearly identify which methods are used, e.g., for number of phases and for aggregation.

7.2.1 Number of phases

Voltage sags normally affect each phase of a three-phase system differently. One, two, or all three phases may see voltages low enough to be called a sag for any one fault event. Even if all three phases experience a sag, the magnitudes will often be different. For a sag in three phases it is thus not immediately evident which magnitude should be taken as the sag magnitude.

One common approach is to present only the lowest of the three phase voltages for each event. This implies a three-phase load that is sensitive to the lowest of the three phases, or single-phase devices spread over the three phases where tripping of one of them interrupts the production process. This method reports only one sag per fault. However, three-phase equipment may be able to survive a severe sag on one phase if the other phases remain above some threshold value, e.g., 87%. Likewise, the same equipment may not survive a less severe sag reported in this way if the other phases are equally low. With this approach, the sag duration is reported as the time until all three phase voltages have recovered above 90%.

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[2] Information on references can be found in 7.13.

A second approach is to report each of the three phases as separate events. This implies single-phase loads or at least single-phase controllers. For monitoring results, the numbers of sags in each of the three phases have to be averaged to obtain an estimation of the number of sags a single-phase load can expect. (Note that a line-to-line connected load might experience a different number of sags than a load connected line-to-neutral.) For prediction methods, normally only the voltages for a single-line-to-ground fault in one phase are calculated. In reality all three phases have an equal probability of a fault. This implies that a sag due to a single-line-to-ground fault or due to a line-to-line fault counts as 1/3 sag with the magnitude of the voltage in phase A, 1/3 sag with the magnitude of the voltage in phase B, and 1/3 sag with the magnitude of the voltage in phase C. A sag due to a three-phase fault simply counts as one sag.

A third approach assumes three-phase loads sensitive to the average voltage of the three phases. This method reports only one sag per event. The reported sag magnitude is therefore the average of the three phases. This magnitude normally does not match any of the three individual phase sag voltages.

7.2.2 Accounting for reclosing—temporal aggregation

Automatic reclosing is common for medium- and high-voltage supply systems exposed to weather elements. This presents another problem for reporting and calculating sag frequency. There are two general methods for reporting the number of sags in the presence of reclosing.

One method counts multiple sags as one sag if they occur within a short period of time, e.g., within 2 min. For example, two sags caused by a high-speed reclose and trip operation count as one sag. The basis for this approach is that utilization equipment will fail on the first sag. Additional sags before the sensitive equipment returns to service are of little interest because they do not affect production. The difficulty is selecting a time period where repeating sags count as one. This may vary with particular production processes. Sometimes during adverse weather, the next sag may also occur before the sensitive equipment returns to normal operation. A problem reported but not documented is that a device could be able to withstand the first sag but will trip on the second or third one.

This method of temporal aggregation of sags requires the selection of a single magnitude and duration to represent several sags. The sag with the lowest magnitude, together with the corresponding magnitude of that sag, may be chosen. Alternatively, the sag with the longest duration, together with the corresponding magnitude of that sag, may be reported. Because equipment sensitivity varies greatly, either selection may misrepresent the affect of the sequence of sags on some utilization equipment.

A second method counts all events even if they occur within a few seconds. For example, two sags caused by a high-speed reclose and trip operation count as two sags. This is a more accurate accounting of sag events but may overestimate the number—and hence the economic impact—of process shutdowns.

For power quality monitoring, either method can be implemented in the monitoring equipment. But prediction techniques depend on reported failure data. The failure data may count each event or it may count several events as one if they all happened in the same automatic reclosing sequence. Sag predictions must accurately consider all of these variations to produce accurate results.

7.2.3 Reporting sag duration

Reporting sag duration presents problems for nonrectangular sags. Most of the techniques in this chapter assume rectangular sags where the duration is clear. However, there are some cases where sags are not rectangular. Faults sometimes change impedance and phase involvement as the fault progresses. The sag may have two or more magnitudes during one event. Large motor loads also modify the shape of sags (see 7.8.1 and Figure 7-1). The duration may be the total time the voltage level meets the sag definition or it could be something else defined by the user. Again, accurate predictions of the number of spurious trips for process equipment will need an accurate understanding of the reported results.

7.2.4 Phase jump during sags

Power system short-circuit faults, in combination with complex network impedances, often result in voltage phase angle jumps as well as magnitude sags. In severe cases, phase jumps in line-neutral voltages result in deep reduction of line-line voltage. These phase jumps are not typically reported in voltage sag surveys and are not considered further in this chapter. However, some types of thyristor phase controlled equipment may be susceptible to misfiring as a result of such jumps.

7.2.5 Point-on-wave of sag initiation and voltage recovery

Some types of equipment, especially electromagnetic relays and contactors, have been shown to be affected by the point on the terminal voltage waveform at which a voltage sag commences (for example, see Djokic, Milanovic, and Kirschen [B6]). Again, this information is not typically reported in voltage sags surveys and is not considered further in this chapter. The sag susceptibility of such equipment can be simply characterized by its worst-case magnitude-duration trip levels.

7.2.6 Voltage sags classification and indices

A method of classifying voltage sags into seven types (A through G), by number of phases sagged and phase angle shifts, has been proposed by Bollen [B3]. These classifications can be useful for including the effect of transformer connections on the sag magnitude (see 7.5.5).

Performance indices for the reliability of electric utility power distribution networks have been developed over many years. Widely used indices include those employed by utility companies to report their performance to regulatory bodies, e.g., system average and customer average frequency and duration of sustained interruptions as defined in IEEE Std 1366™-2003 [B16]. Similar system average momentary interruption indices and voltage sag indices have been proposed for rms voltage deviations and are under consideration in standards development. Other proposed indices include consideration of the energy lost during a sag.

7.2.7 Magnitude-duration charts

It is useful to summarize a collection of voltage sag, swell, and interruption event data graphically, with each sag event plotted as a single point. Typically, the vertical Y axis extent is the magnitude of the worst-case rms voltage recorded on any of the three-phase voltages during the event. The horizontal X axis extent is the event duration, typically shown on a logarithmic scale, for which rectangular sags are assumed. The magnitude scale may be in volts or in percentage or per unit of the nominal system voltage. The duration scale may be in time units of cycles (with system frequency specified), milliseconds, or seconds.

Figure 7-1 shows a recorded voltage sag event waveform (only the first 50 ms of the recorded instantaneous voltages are shown here), the cycle-by-cycle rms voltage profile, and its corresponding point in the magnitude-duration plane (from Brumsickle et al. [B4]). The rms voltages are computed once per half-cycle, using the instantaneous voltage values sampled the previous half-cycle. The coordinates of the magnitude-duration point in Figure 7-1 are determined by the minimum observed rms voltage on any of the three phases (the magnitude value of 38% in this case) and by the time interval between rms voltage falling below 90%—designated time zero—and all three rms voltages returning to >90% (the duration value of approximately 230 ms). Many of the sag reporting issues of 7.2 are illustrated by Figure 7-1.

7.3 Equipment susceptibility to voltage sags

Industrial and commercial process equipment shows a wide variation of sensitivity to voltage sags, among the same type of device from different vendors, or even among different models from the same vendor. No uniform standard for voltage sag tolerance yet exists, although some industry segments have developed minimal standards (see the semiconductor fabrication industry's SEMI F47-0200 [B27]). Recent IEC standards (IEC 61000-4-11:2004 [B12] and IEC 61000-4-34:2005 [B14]) suggest several voltage sag and momentary interruption levels at which equipment can be tested for susceptibility.

A widely used example of equipment susceptibility is the ITI/CBEMA magnitude-duration curve {ITI (CBEMA) Curve Application Note [B21]}, shown in Figure 7-2, which describes the typical—not guaranteed—response of most information technology equipment (e.g., personal computers and fax machines) to voltage variations. The curve is applicable only to 120 V 60 Hz single-phase equipment.

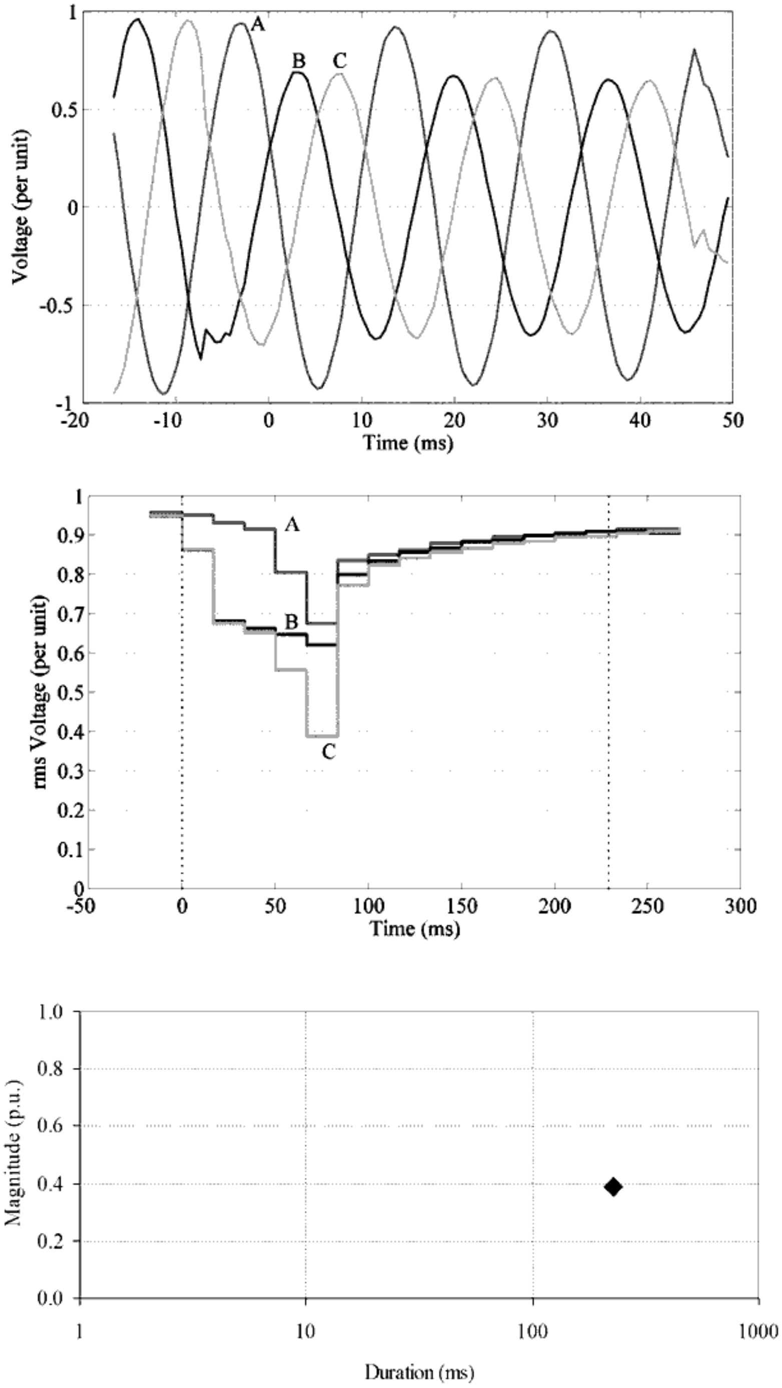

Figure 7-1—Voltage sag representation: voltage waveform (top, only first 50 ms shown); rms voltage profile (middle); magnitude-duration plot (bottom)

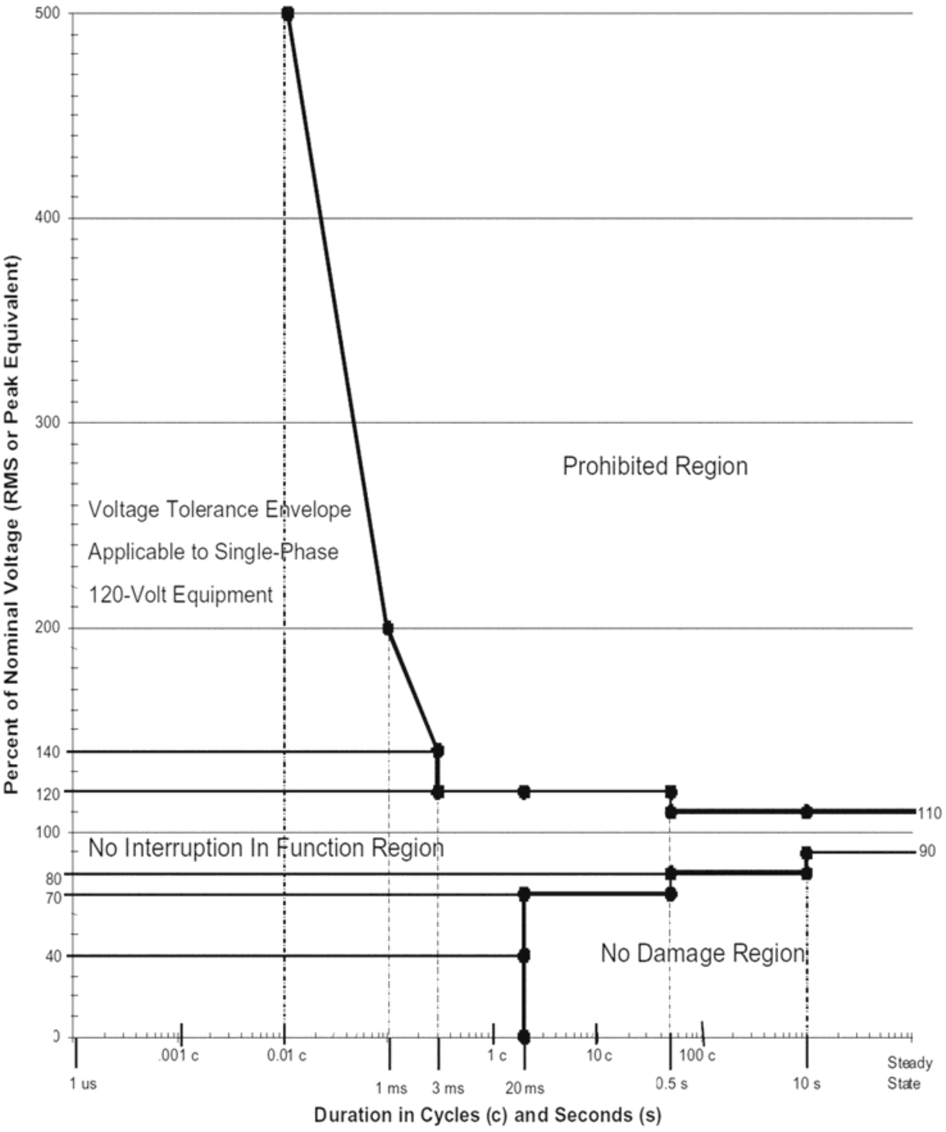

Figure 7-2—ITI/CBEMA curve

The susceptibilities of adjustable speed drives (ASDs), motor starter contactors, programmable logic controllers (PLCs), control relays, high-intensity discharge (HID) lamps, and photo-eye sensors are all known to differ significantly from the ITI/CBEMA levels (see Annex C of IEEE Std 1346™). IEEE Std 1100™ *(IEEE Emerald Book™)* [B15] provides further detail on equipment susceptibility and voltage sag mitigation options; the next revision of that standard is expected to include updated material. IEEE Std 1346 and

7.9 provide guidance for combining voltage sag predictions with known equipment susceptibilities to estimate of the annual number of sag-related process interruptions.

Voltage sags are one important component of *power quality*—the compatibility of the electricity supply with end-use equipment. The classification of power quality phenomena is described in IEEE Std 1159. As this chapter is being prepared, many IEEE standards related to power quality are under development, coordinated by the Power Quality Subcommittee of the IEEE Power Engineering Society (PES).

7.4 Line faults—A major cause for voltage sags

Some studies found that nearly all disruptive voltage sags were caused by current flowing to short circuits either within the plant or on utility lines in the electrical neighborhood (see Conrad, Grigg, and Little [B5] and Key [B22]). Motor starting and welders can also cause voltage sags with predictable characteristics. This chapter concentrates on sags associated with short circuits (i.e., faults) on the electrical supply system. The principal voltage drop occurs only while short-circuit current flows. Voltage increases as soon as a fault-clearing device interrupts the flow of current. These faults may be many kilometers from the interrupted process, yet be close enough to cause problems. A clear understanding of voltage drop during faults and the fault-clearing process is necessary before attempting to make accurate voltage sag predictions.

Consider the simple distribution system in Figure 7-3 to understand how faults create voltage sags. It shows a 20 MVA substation with three distribution feeders. Each feeder has a circuit breaker with protective relays to detect and clear faults. Feeder F1 shows more detail with fuses and reclosers. Point “C” is an industrial or commercial site supplied 480Y/277 V from a distribution transformer.

The lower half of Figure 7-3 shows what happens to the rms voltage when a temporary three-phase fault occurs at “A” on feeder F2. The dashed line shows the rms voltage at point “B,” and the solid line shows rms voltage on feeders F1 and F3 during the same fault. The load at “C” will also see the voltage represented by the solid line. A time line shows the sequence of events. Note that F2 uses reclosing relays. Reclosing can cause several sags for one permanent fault. Also, the voltage decay on the first interruption represents motor voltage decay. The motors trip off before the reclose.

All loads on F2 including “B” suffer a complete interruption when breaker F2 clears the fault—these will be momentary interruptions if the fault clears before the final recloser operation. All loads on F1 and F3 see two voltage sags. The first sag begins at the initiation of the fault. The second sag begins when breaker F2 recloses. Sags occur whenever fault current flows through impedance to a fault. Voltage returns to normal on feeders F1 and F3 once the breaker on F2 interrupts the flow of current. Unfortunately, sensitive loads on F1 and F3 experience a production outage if the sag magnitude and duration are more severe than the withstand capability of the sensitive load. Sags also occur for single- and two-phase faults. The magnitude is often different on each of the three phases (see 7.5.1).

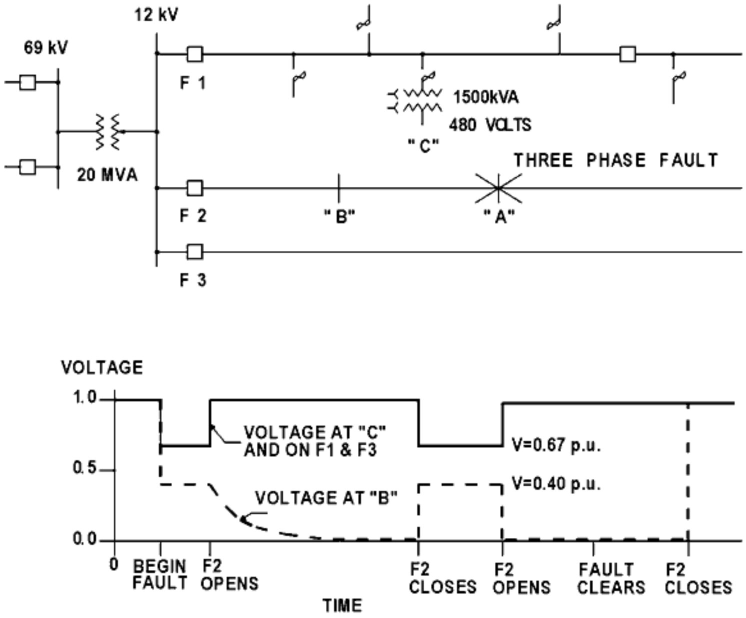

Figure 7-3—Voltage sags from faults and fault clearing

Faults on industrial and commercial power systems produce the same voltage sag phenomena. A fault on one feeder drops the voltage on all other feeders in the plant. The voltage sag may even show up in the utility system.

The voltage sag magnitude at a specific location depends on system impedance, fault impedance, transformer connections, and the pre-sag voltage level. The impact of the sag depends upon equipment sensitivity.

7.5 Voltage sag predictions

Voltage sags associated with fault clearing have many predictable characteristics. It is possible to predict the sag magnitude for individual faults by calculating the voltage drop at the critical load. Predicting how long the voltage sag will last requires an estimate of the total clearing time for the overcurrent protective device. The waveform of voltage sags is somewhat predictable from analysis of available recorded voltage sag data and with the aid of transient network analysis. However, it is most important to estimate how often voltage sags will upset sensitive electrical equipment.

Predicting characteristics for one sag caused by a specific fault at a specific location is straightforward: Prepare an accurate electrical model of the system, apply the fault, and calculate the voltage sag magnitude at the critical load. Use the protective device characteristics to estimate sag duration. Compare the sag characteristics with the sensitive equipment capability to determine if the process will have an outage.

Predicting sag characteristics a sensitive load will see during several years of operation requires a probabilistic approach. It is impossible to predict exactly where each fault will occur, but it is reasonable to assume that many faults will occur. The most accurate predictions require sag calculations for every possible fault on the electrical system and estimating each fault's frequency of occurrence. The overall sag frequency is the sum of the individual frequencies. A practical approach is to locate boundaries on the electrical system where specific sag magnitudes are possible; then estimate the fault frequency in the boundary.

Predicting sag characteristics for urban distribution systems that are frequently reconfigured may require a significant degree of cooperation and communication between commercial and industrial electricity consumers and distribution utilities.

7.5.1 Magnitude of individual sags

The ability to calculate sag magnitudes for any specific fault is essential to the prediction process. It requires knowledge of network impedances, fault impedance, and fault location relative to the sensitive load. It is also necessary to know the transformer connections and pre-sag voltages. A model based on phasors is suitable for these calculations. This approach provides a steady-state solution—the remaining voltage during the sag. Voltage and impedance quantities in the following expressions are considered to be phasors.

Figure 7-4 shows the basic impedance divider needed to calculate sag magnitude, as shown in Equation (7.1):

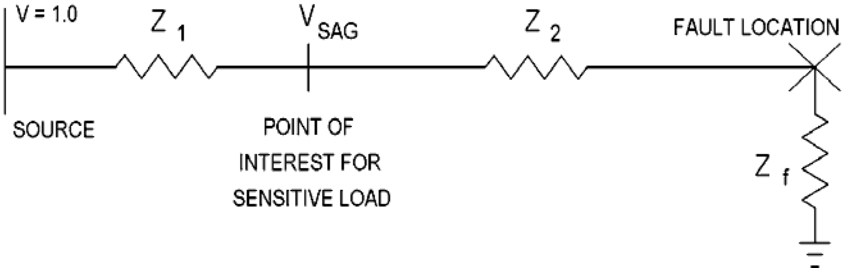

Figure 7-4—Basic impedance divider for sag magnitude

$$V_{\text{sag}} = \frac{Z_2 + Z_f}{Z_1 + Z_2 + Z_f} \text{ p.u.} \tag{7.1}$$

Figure 7-5 and Equation (7.2), Equation (7.3), and Equation (7.4) illustrate sag calculations for a three-phase zero impedance fault ($Z_f = 0$). Figure 7-5 shows the positive sequence reactances of the supply for F2 of Figure 7-3 with a three-phase zero-impedance fault at "A." Use of the reactance only simplifies the calculations to demonstrate the concept. In practice, it will be necessary to also consider resistance, sequence components, etc.

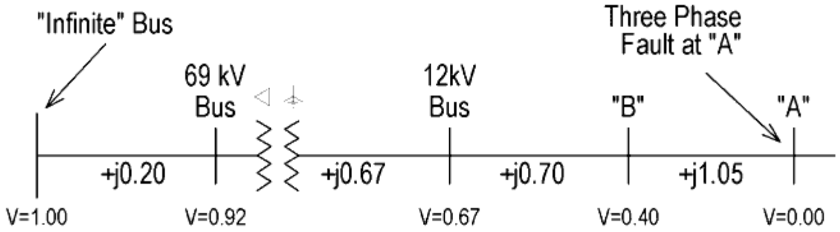

Figure 7-5—Impedance diagram and voltage sags for Figure 7-3

Equation (7.2) through Equation (7.4) show impedance divider calculations to predict voltage sag magnitudes. While fault current is flowing from the infinite bus to "A," the voltage at "B" is shown in Equation (7.2):

$$V_B = \frac{\mathrm{j}1.05}{\mathrm{j}0.20 + \mathrm{j}0.67 + \mathrm{j}0.70 + \mathrm{j}1.05} = 0.40 \text{ p.u.} \tag{7.2}$$

The voltage at the 12 kV bus and all loads on F1 and F3 including "C" in Figure 7-3 is shown in Equation (7.3):

$$V_{12\mathrm{kV}} = \frac{\mathrm{j}0.70 + \mathrm{j}1.05}{\mathrm{j}0.20 + \mathrm{j}0.67 + \mathrm{j}0.70 + \mathrm{j}1.05} = 0.67 \text{ p.u.} \tag{7.3}$$

The voltage at the 69 kV bus is shown in Equation (7.4):

$$V_{69\mathrm{kV}} = \frac{\mathrm{j}0.67 + \mathrm{j}0.70 + \mathrm{j}1.05}{\mathrm{j}0.20 + \mathrm{j}0.67 + \mathrm{j}0.70 + \mathrm{j}1.05} = 0.92 \text{ p.u.} \tag{7.4}$$

These simple calculations show how one feeder fault can disrupt an entire electrical neighborhood. The calculations used only reactance to demonstrate the impedance divider principle. Accurate studies may require all impedance information including resistance and reactance of positive, negative, and zero-sequence components and the impedance of the fault (see fault calculations in, e.g., Anderson [B1] and detailed sag calculations for radial and non-radial systems in Bollen [B3]). However, the concept is identical to the simple three-phase reactance calculations.

The impedance divider concept also applies to the transmission network; however, the calculations are more difficult. This normally requires a computer program for network fault analysis. Network computer models allow the user to predict voltage sag magnitude at the sensitive load for any type of fault anywhere in the network; 7.6 provides additional detail on computation techniques. Figure 7-6 shows a simplified one-line diagram with sag magnitudes on part of a transmission network supplying sensitive loads.

Table 7-4 shows results of computer analysis of a network containing over a thousand buses. It shows the per-unit voltage at remote buses in a large network for faults at one

EHV bus. The magnitudes represent output voltages from distribution substations supplied from the transmission system through one delta-wye transformer. Only the lowest phase voltage is listed for the phase-to-phase and phase-to-ground faults. For example, one bus 56 km from the faulted bus will see 0.67 per-unit voltage during a three-phase fault. The lowest phase voltage on a bus 86 km away will be 0.84 p.u. for a phase-to-ground fault on the same EHV bus. (This assumes all prefault voltages are 1.0 p.u.)

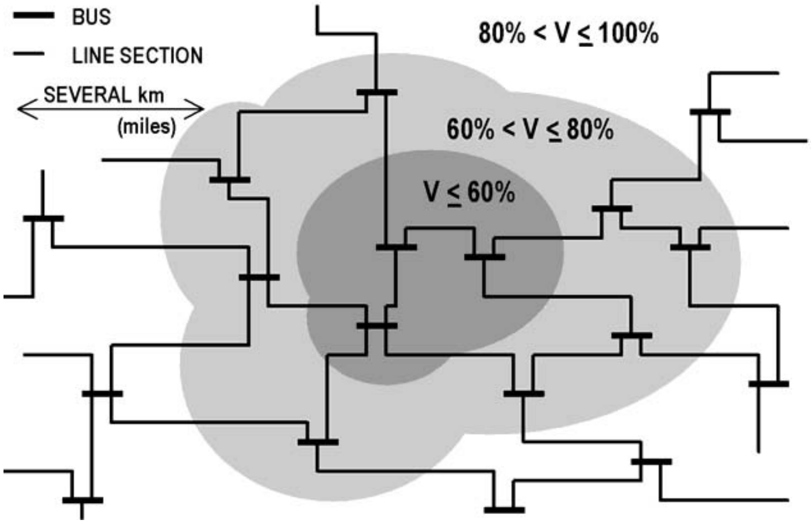

Figure 7-6—Transmission network voltage sag profile

Table 7-4—Network voltage vs. distance from EHV fault

Distance from the fault (km)	Lowest phase voltage for each type of fault		
	3-phase	Phase-to-phase	Phase-to-ground
0 to 8	0 to 0.6	0 to 0.7	0 to 0.75
42	0.71	0.82	0.87
56	0.67	0.76	0.81
64	0.71	0.78	0.84
86	0.84	0.88	0.91
153	0.94	0.97	0.95
156	0.88	0.91	0.92

Clearly, one high-voltage fault can produce disruptive voltage sags in many cities and over several hundred square kilometers. Also, physical distance does not translate directly to electrical "distance." A bus 42 km from the fault saw a less severe voltage sag than a bus 56 km away.

7.5.2 Duration of sags

Each voltage sag lasts as long as the protection equipment allows fault current to flow. There are many types of fault-clearing equipment. Each has an absolute minimum time that it takes to clear faults. In addition, intentional time delay is commonly introduced to provide coordination between devices in series. Furthermore, many line faults are temporary. Automatic reclosing may be used to reenergize the line and restore service within a few seconds, as in the example of Figure 7-3. The clearing times for some commonly used devices are listed in Table 7-5, along with a possible number of retries for automatic reclosing. (See IEEE Power System Relaying Committee Reports [B19], [B20].)

Figure 7-7 summarizes the sag duration probability distribution for voltage sag data reported in various papers (see Conrad, Grigg, and Little [B5], Dorr [B7], Goldstein and Speranza [B9], and Gulachenski [B10]). Notice that 60% to 80% of the reported voltage sags lasted less than 2/10 of one second. Also notice the steep rise in the curve just less than 1/10 of one second, which corresponds to minimum clearing time for oil circuit breakers.

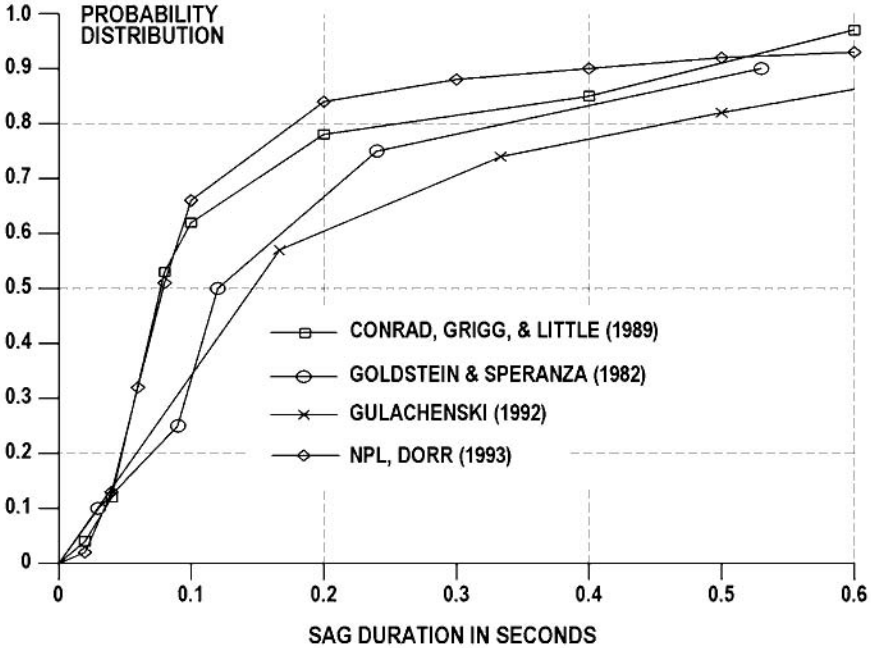

Figure 7-7—Voltage sag duration probability distribution

Table 7-5—Typical clearing times

Type of fault-clearing device	Clearing time in cycles		
	Typical minimum	Typical time delay	Number of retries
Expulsion fuse	0.5	0.5 to 60	None
Current-limiting fuse	0.25 or less	0.25 to 6	None
Electronic recloser	3	1 to 30	0 to 4
Oil circuit breaker	5	1 to 60	0 to 4
SF_6 or vacuum breaker	3 to 5	1 to 60	0 to 4

7.5.3 Frequency—How often sags occur

Predicting the voltage sag frequency, or how often voltage sags may occur, requires an accurate network impedance model and reliability data for all equipment in the electrical "neighborhood." Reliability data for transformers, lines, and other equipment is available in the annexes of this recommended practice. Annex N provides data on high-voltage transmission lines. Utility power lines that are many kilometers long and exposed to adverse weather are often a major cause for voltage sags.

The problem is to determine which components in the electrical network cause a "significant" voltage sag when faulted, and then determine the probability that each fault will occur. Lines, feeders, and branch circuits present special problems because the voltage sag magnitude depends upon the fault location. Sags farther away are generally less severe. A complete picture requires calculations for every possible fault and every possible fault impedance. It is often convenient to identify what portions of each line can cause "significant" sags when those portions experience a fault.

For example, refer again to the radial system of Figure 7-3. The sag magnitude for load "C" becomes less severe as fault "A" occurs farther and farther from the 12 kV bus. Assume the source reactance to the 12 kV bus $Z_1 = 0.87$ p.u. and calculate sag voltages for three-phase faults using only reactance values. From Equation (7.1), the voltage will sag to 50% when reactance $Z_2 = 0.87$ p.u. and fault impedance $Z_f = 0$. If Z_2 is a line whose reactance is 0.21 p.u./km, then Z_2 represents 4.14 km of line. Any zero impedance fault less than 4.14 km from the bus will cause the voltage to drop to 50% of nominal or lower. Likewise, faults anywhere from zero to 16.67 km from the substation can cause sags to 80% or lower.

Now assume the feeder has a uniform fault rate of 0.12 three-phase faults per kilometer per year to calculate the frequency of occurrence. There are 4.14 km of line on F2 that can cause sags to 50% or lower. Therefore, Equation (7.5) shows faults on feeder F2 are likely to cause 0.5 sags per year less than or equal to 50% of pre-sag voltage for the load at “C.”

$$\mathrm{Sag}_{50\%} = 0.12\frac{\mathrm{faults}}{\mathrm{km-year}} \times 4.14\ \mathrm{km} = 0.5\frac{\mathrm{sags}}{\mathrm{year}} \tag{7.5}$$

Likewise, Equation (7.6) shows faults on F2 are expected to cause 2.0 sags per year with magnitude from 0% to 80% for load “C.”

$$\mathrm{Sag}_{80\%} = 0.12\frac{\mathrm{faults}}{\mathrm{km-year}} \times 16.67\ \mathrm{km} = 2.0\frac{\mathrm{sags}}{\mathrm{year}} \tag{7.6}$$

Notice that faults on F3 will also cause voltage sags for the critical load. Repeat the calculations for each component on F3 that can cause significant voltage sags. Add the expected numbers for each component to arrive at the total frequency prediction. If F3 is identical to F2, “C” can expect 1.0 sag per year from 0% to 50% of nominal and 4.0 sags per year from 0% to 80% of nominal from F2 and F3. Repeating these calculations for all components where faults will cause significant voltage sags gives users a clear idea of what might be called the area of vulnerability. These areas may be highlighted on schematics or maps like Figure 7-6 to clearly identify the area.

One good way to display voltage sag frequency is to plot the number of events vs. sag voltage in percent of nominal as shown in Figure 7-8. The graph shows how many nuisance shutdowns are expected as a function of voltage sensitivity. Select several different voltage sag magnitudes, perform network analysis, and accumulate the number of sags that will be worse than or equal to each voltage threshold. Plot points for number of events vs. voltage and draw the curve.

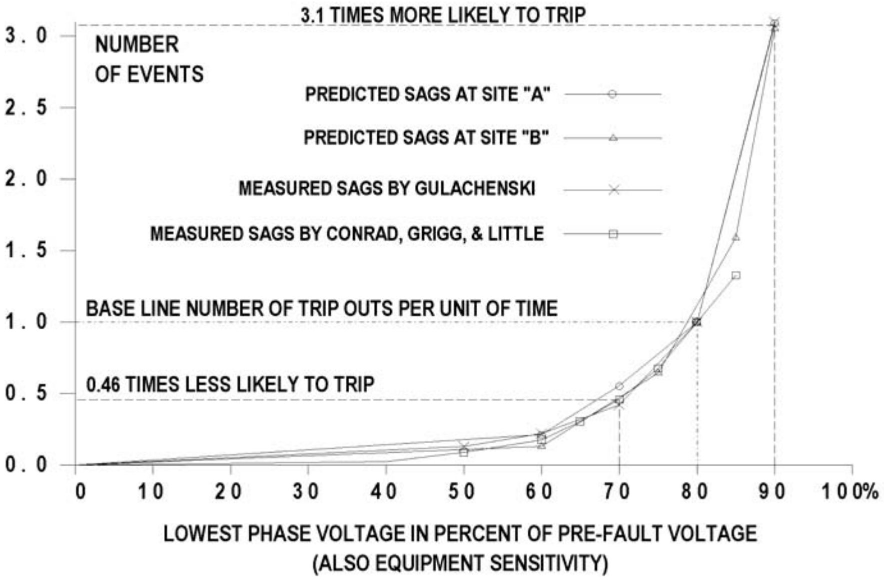

Figure 7-8—Sag magnitude relative number of events

The most severe sags occur infrequently because a relatively small amount of line exposure can produce severe sags (see Figure 7-6). However, several hundred kilometers of line and many components might cause voltage sags to 90% of nominal. Therefore minor (shallow) sags, such as sags to 90%, occur much more frequently. It is common for minor sags to occur five to ten times more often than severe (deep) sags.

Experience shows that sag frequency vs. magnitude curves have the same general shape. Figure 7-8 summarizes predictions and measured data from various sites. The actual number of events is different at each site, so Figure 7-8 is normalized for 1.0 event per year at 80% of nominal voltage. This curve is very useful to estimate the impact of equipment undervoltage trip settings. The dashed lines compare 70% and 90% trip settings to the normalized 80% trip setting. Sag-related outages for 70% trip settings are about 0.46 times less likely, while 90% trip settings are 3.1 times more likely to cause sag outages. Therefore, a trip setting at 90% of nominal would be 3.1 divided by 0.46, or 6.7 times more likely to cause nuisance trip-outs than the 70% trip setting.

7.5.4 Waveform

Most sags due to fault clearing have very similar characteristics. Faults usually begin when the half-cycle voltage is something greater than zero because arcing begins prior to physical contact. This creates a fast transition to the lower voltage and some asymmetry. The voltage sag ends when the fault-clearing device interrupts fault current. This usually occurs near a forced current zero. Therefore, the voltage sag ends with a quick transition from the reduced magnitude to the normal magnitude sine wave. Figure 7-9 shows a typical sag with 86% magnitude and 0.09 s duration. Although not shown, the sag magnitude was different on each of the other two phases. Motor loads on an industrial power system can change the typical voltage sag waveform, as discussed in 7.8.1.

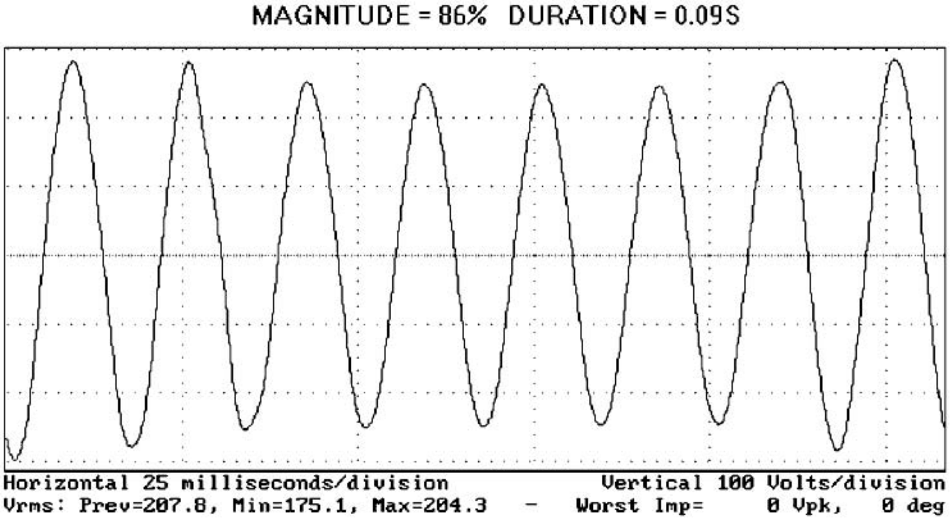

Figure 7-9—Typical sag waveform

7.5.5 Effect of transformer connections

Three-phase transformer stations connected delta-wye or wye-delta will alter unbalanced voltage sags. Roughly, a phase-to-ground voltage sag turns into a phase-to-phase sag, less the zero-sequence component, as it passes through any delta-wye transformer. Passing that sag through another delta-wye transformer returns something like the original phase-to-ground voltage sag less the zero-sequence component.

Table 7-6 shows one example of the effect transformer connections have on a sag caused by a phase-to-ground fault. The fault is on the solidly grounded wye-wye system that supplies the first delta-wye transformer. The first delta-wye transformer then supplies the second delta-wye transformer. Notice the A phase-to-ground sag magnitude on the wye-wye system is more severe because zero-sequence voltages are present only on the wye-wye side.

Table 7-6—Impact of transformer connections

Type of transformer connection	Phase-to-ground voltage in per unit of phase-to-ground			Phase-to-phase voltage in per unit of phase-to-phase		
	A	B	C	A-B	B-C	C-A
Grounded wye-wye	0.644	0.986	0.988	0.796	1.000	0.835
First delta-wye	0.835	0.796	1.000	0.745	0.926	0.959
Second delta-wye	0.959	0.745	0.926	0.835	0.796	1.000

This shows the importance of including the effects of transformers in the calculations. It also offers one small opportunity for controlling the effect of voltage sags. If a particular piece of equipment is known to be sensitive only to phase-to-phase voltage sags, and the sags are known to primarily be caused by one type of fault, a particular transformer connection may help to reduce the problems. A more detailed discussion of the effect of transformer connections is provided in Melhorn, Hofmann, and Samotyj [B24] and Bollen [B3].

7.5.6 Effect of pre-fault voltage

All of the voltage sag magnitude calculations in this chapter assume the pre-fault or pre-sag voltage is 100% of nominal. The calculations give sag voltages that are actually in percent of the pre-sag voltage. Therefore, compensation is required if the actual pre-sag voltage is higher or lower than nominal. This is important for sensitive equipment. Pre-sag voltages different from the assumed 100% can cause significant errors in predicting the number of nuisance trips.

For example, consider sag outage predictions for equipment sensitive to 80% sags. A calculated 82% sag with 95% pre-sag voltage actually produces 78% voltage. The equipment may trip even though predictions assuming 100% pre-sag voltage say it would not. A calculated 77% sag might not trip the equipment if the pre-sag voltage is 105%.

Operating below nominal voltage increases apparent sensitivity and increases the number of nuisance sag outages. Operating above nominal before the sag decreases the apparent sensitivity and reduces the number of sag outage problems. The slope of Figure 7-8 for an 80% trip setting is such that a 1% change in pre-sag voltage changes the predicted number of sag trip outs by 10% to 15%.

7.5.7 Effect of fault impedance

Fault impedance is very important to sag magnitude calculations, especially on lower voltage systems. Recalling Equation (7.1), the sag magnitude is shown in Equation (7.7):

$$V_{\text{point of interest}} = \frac{Z_2 + Z_f}{Z_1 + Z_2 + Z_f} \tag{7.7}$$

where

Z_f is the fault impedance

The additional fault impedance generally makes sags less severe than zero impedance faults. For example, consider the system in Figure 7-10. It consists of two feeders where faults can cause sags for the sensitive load on the third feeder. The impedance of each feeder section and number of faults per year are shown next to each section.

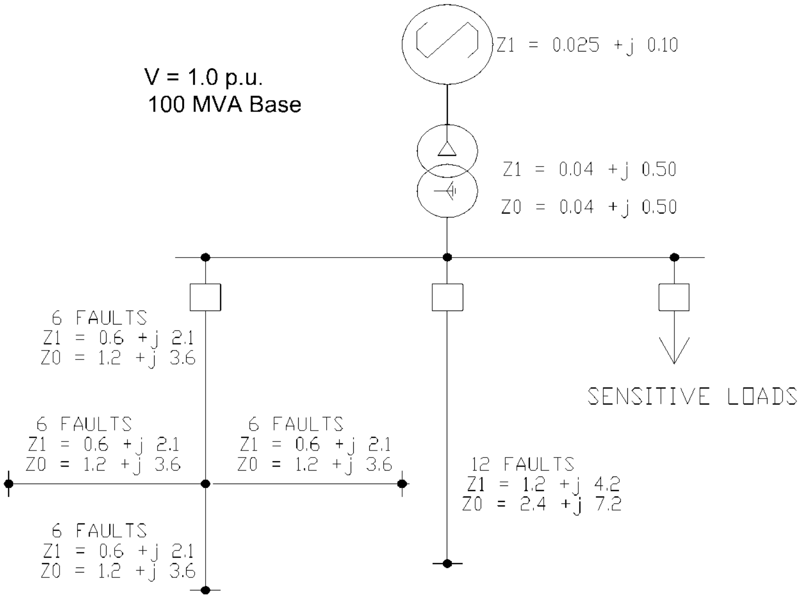

Figure 7-10—Diagram of radial system for effect of fault impedance

Table 7-7 summarizes calculations using three different fault impedances for the system in Figure 7-10. It shows sag events per year for phase-to-phase faults selecting the lowest magnitude of the three-phase voltages. The calculations used macros in a computer fault analysis package that divided each line into ten equal segments. Table 7-7 shows the number of sags for zero impedance, 1 Ω resistance, and 5 Ω resistance faults. Notice that the 5 Ω resistance causes no voltage sags deeper than 80% of nominal anywhere on the system. The fault impedance values are only used for this example and are not considered typical.

Table 7-7—Effect of fault impedance on sag voltage for phase-to-phase faults

Lowest phase sag voltage (%)	Sags per year		
	$Z_f = 0\ \Omega$	$Z_f = 1\ \Omega$	$Z_f = 5\ \Omega$
60	1.68	1.05	0
70	2.52	2.31	0
75	3.36	3.15	0
80	4.83	4.20	0
85	8.61	8.19	0.21
90	12.6	12.6	10.9

7.6 Methods of stochastic prediction of voltage sags

This subclause provides additional detail for two methods of predicting voltage sags.

7.6.1 Method of critical distances

A fast assessment method for voltage sags on radial distribution systems was recently proposed by Bollen [B3]. Rather than calculate the sag voltage resulting from possible fault locations, the fault location needed to produce a given sag voltage is determined. Although the method is based on several simplifications, it can facilitate an estimate of voltage sag magnitudes when detailed utility data is not available. Only the following data are needed:

a) Number of lines (feeders) originating from the substation

b) Fault level (fault rate) of the substation

c) Feeder impedance per unit length

Referring to Figure 7-4 and recalling again Equation (7.1), the total impedance between the point of interest, or point of common coupling (PCC), and the fault can be related to *z* the feeder impedance per unit length and L the distance between the PCC and the fault, resulting in Equation (7.8) for the sag magnitude.

$$V_{\text{sag}} = \frac{zL}{Z_1 + zL} \tag{7.8}$$

The voltage at the PCC drops below a critical voltage V_{crit} whenever a fault occurs within the critical distance from the PCC, as given by Equation (7.9)

$$Z_{\text{crit}} = \frac{Z_1}{z} \cdot \frac{Z_{\text{crit}}}{1 - V_{\text{crit}}} \tag{7.9}$$

Equation (7.9) is valid for three-phase symmetrical faults if for Z_1 and z the positive sequence impedances are used. For single-phase faults the sum of positive, negative, and zero-sequence impedances should be used; for phase-to-phase faults, use the sum of positive and negative sequences. The voltage in the expression is the phase-neutral voltage for single-phase faults and the voltage between faulted phases for phase-phase faults.

Equation (7.9) can be used to estimate the exposed area at every voltage level in the supply to a sensitive load. The exposed area contains all fault positions that lead to a voltage sag causing a spurious equipment trip. The expected number of spurious trips is found by adding the failure rates of all equipment within the exposed area.

To estimate the number of sags below a certain magnitude it is sufficient to add all lengths of lines and cables within the critical distance from the PCC, this is the *exposed length*. The resulting exposed length is multiplied by the fault rate (faults per km per year) to obtain the number of sags per year.

7.6.2 Method of fault positions

The method of fault positions employed in 7.5 was first introduced by Conrad [B1] and is also used by major utility companies to estimate the number of sags due to faults on their distribution systems. Commercial software packages are available using the following method:

a) Determine the area of the system in which short circuits will be considered.

b) Split this area into small parts. Short circuits within one part should lead to voltage sags with similar characteristics. Each small part is represented by one *fault position* in a circuit model of the power system.

c) For each fault position, the short circuit frequency (faults per year) is determined.

d) By using the circuit model of the power system the sag characteristics are calculated for each fault position. Any power system model and any calculation method can be used, although the impedance matrix model allows the most efficient calculations (see Anderson [B1]).

e) The results from the two previous steps are combined to obtain stochastic information about the number of sags with characteristics within certain ranges.

Clearly, the accuracy of the calculation, together with the calculation effort, is increased as the number of fault positions is increased. As a starting point, several positions on each parallel feeder are recommended. Examples are discussed in 7.7.

A complicating factor is the finite probability that the primary protection will fail for a given fault. Backup protection typically has much longer clearing times, resulting in voltage sags of significantly longer duration. To include failure of the protection, two events can be considered for each fault position: one representing clearing by the primary protection, the other fault clearing by the backup. The two events will typically be given different fault frequencies.

7.7 Examples for rectangular sag calculations

The following examples show sample calculations to predict voltage sag performance. The first example is simplified to use only three-phase short circuits with zero fault impedance on a radial system. The second example demonstrates a more complete symmetrical component fault analysis on a larger network assuming zero impedance faults. Users are cautioned that the best predictions require accurate models including fault type, fault impedance, transformer connections, network impedance models, and knowledge of pre-sag voltages.

7.7.1 Radial distribution example

Consider the simple two-feeder system in Figure 7-11. A load on F1 is sensitive to voltage sags and needs to know how many sags to expect from F2. The customer with sensitive loads will consider purchasing ride-through capability, but sag magnitude information is needed. For this example, consider all faults to be bolted three-phase only. Also assume pre-fault voltages are 1.0 p.u.

The source reactance to the feeder bus is + j0.50 p.u. F2 is 12 km long with a reactance of 0 + j0.4 p.u. per kilometer. The frequency for three-phase faults is 0.15/km/year.

The first step is to calculate the points where faults can cause voltage sags of various magnitudes. Figure 7-11 shows locations on F2 where three-phase faults will reduce the feeder bus voltage to drop 0.4 to 0.9 p.u. of pre-sag voltage in 0.1 p.u. increments. The voltage and distance from the distribution bus are noted on F2 in Figure 7-11.

Any fault closer to the feeder bus can cause voltage sags worse than those at the point of interest. For example, three-phase faults between the bus and 5 km out will cause a sag at least to 0.8 p.u. Faults farther than 5 km away cannot possibly drop the voltage lower than 0.8 p.u.

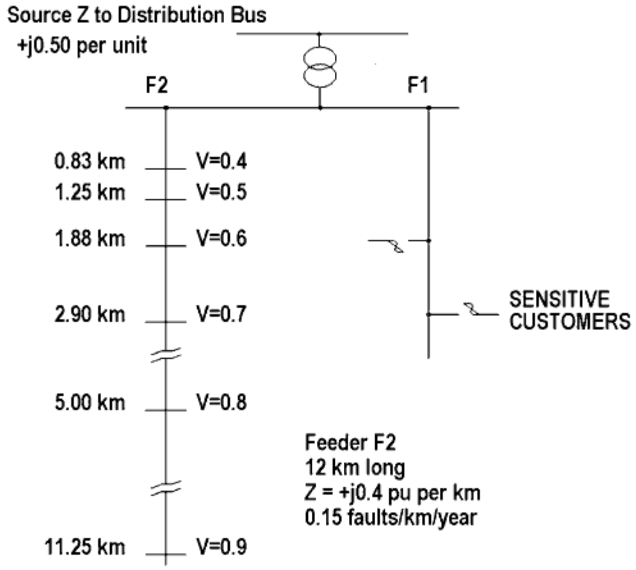

Figure 7-11—Radial distribution example one-line diagram

Table 7-8 summarizes the distances and number of events for the voltage sag magnitudes of interest. The right-hand column is the number of voltage sags that will be worse than or equal to the voltage listed in column 1.

Figure 7-12 shows a graph of the sag frequency vs. magnitude from Table 7-8. Notice how the number of events increases dramatically with increased sensitivity. This is the same curve shape as data presented in Figure 7-8. Addition of another feeder identical to F2 doubles the probability of voltage sags. The complete picture must also include the number of voltage sags from the plant distribution system and the transmission network.

Table 7-8—Radial distribution example sag calculations

Lowest phase sag voltage per unit	Line exposure (km)	Events per km per year	Number of sags less than or equal to sag voltage
0.40	0.83	0.15	0.12
0.50	1.25	0.15	0.19
0.60	1.88	0.15	0.28
0.70	2.90	0.15	0.44
0.80	5.00	0.15	0.75
0.90	11.25	0.15	1.69

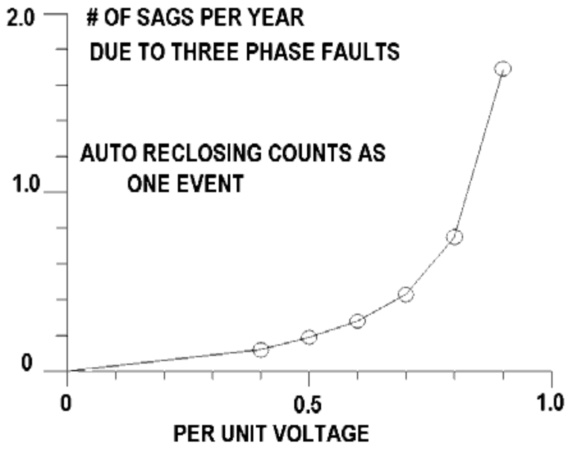

Figure 7-12—Number of sags from radial distribution example

7.7.2 Transmission network example

Table 7-9, Table 7-10, Table 7-11, and Table 7-12 summarize the results of a detailed prediction of sag magnitudes from a large transmission network. A network fault analysis program calculated voltage at the sensitive load for three-phase, single-line-to-ground, line-to-line, and double-line-to-ground faults. All faults were assumed to have zero impedance. The voltage ranges at the sensitive load site are 0.0 to 0.60, 0.60 to 0.75, 0.75 to 0.85, and 0.85 to 0.90 per unit of the pre-sag voltage. The fault analysis applied faults at all buses and many positions along each line to identify what parts of the system can cause sags in the ranges of interest.

The limits of vulnerability for each component and line were highlighted on a map similar to Figure 7-6. Line exposure distances were estimated for each of the four sag categories for each of the four types of fault for each of the four system voltages. Table 7-9 summarizes this work for the 345 kV lines. Table 7-10 is the same summary for 230 kV, etc. Each table multiplies the kilometers of exposure by the failure rate for each fault type. Totals for sag events in each sag voltage range are highlighted in boldface on the bottom row of each table.

Table 7-9—Sag events from the 345 kV system

Type of fault	Events per km per year	Voltage sag events in each voltage range (lowest sag magnitude of three phases)							
		0 to 60 km	**Events**	**0.60 to 0.75 km**	**Events**	**0.75 to 0.85 km**	**Events**	**0.85 to 0.90 km**	**Events**
Phase-to-ground	0.0209	0	0.00	0	0.00	16	0.33	53	1.11
Two phase-to-ground	0.0016	0	0.00	0	0.00	66	0.11	192	0.31
Phase-to-phase	0.0002	0	0.00	0	0.00	64	0.01	187	0.04
Three phase	0.0002	0	0.00	23	0.00	151	0.03	153	0.03
Total	0.0229	0	**0.00**	23	**0.00**	298	**0.48**	584	**1.49**

Table 7-10—Sag events from the 230 kV system

Type of fault	Events per km per year	Voltage sag events in each voltage range (lowest sag magnitude of three phases)							
		0 to 60 km	**Events**	**0.60 to 0.75 km**	**Events**	**0.75 to 0.85 km**	**Events**	**0.85 to 0.90 km**	**Events**
Phase-to-ground	0.0132	0	0.00	0	0.00	0	0.00	0	0.00
Two phase-to-ground	0.0026	0	0.00	0	0.00	0	0.00	0	0.00
Phase-to-phase	0.0002	0	0.00	0	0.00	0	0.00	0	0.00
Three phase	0.0002	0	0.00	0	0.00	0	0.00	55	0.01
Total	0.0167	0	**0.00**	0	**0.00**	0	**0.00**	55	**0.01**

Table 7-11—Sag events from the 138 kV system

Type of fault	Events per km per year	Voltage sag events in each voltage range (lowest sag magnitude of three phases)							
		0 to 60 km	Events	0.60 to 0.75 km	Events	0.75 to 0.85 km	Events	0.85 to 0.90 km	Events
Phase-to-ground	0.0217	0	0.00	60	1.30	71	1.54	77	1.67
Two phase-to-ground	0.0051	10	0.05	109	0.56	105	0.53	77	0.39
Phase-to-phase	0.0018	10	0.02	87	0.17	98	0.18	69	0.12
Three phase	0.0012	71	0.09	82	0.10	101	0.12	98	0.12
Total	0.0298	91	**0.16**	348	**2.13**	375	**2.38**	321	**2.30**

Table 7-12—Sag events from the 69 kV system

Type of fault	Events per km per year	Voltage sag events in each voltage range (lowest sag magnitude of three phases)							
		0 to 60 km	Events	0.60 to 0.75 km	Events	0.75 to 0.85 km	Events	0.85 to 0.90 km	Events
Phase-to-ground	0.0400	6	0.24	18	0.72	32	1.28	68	2.72
Two phase-to-ground	0.0135	24	0.32	47	0.63	132	1.78	220	2.97
Phase-to-phase	0.0043	24	0.10	39	0.17	130	0.56	203	0.87
Three phase	0.0037	37	0.14	69	0.26	169	0.63	191	0.71
Total	0.0615	91	**0.80**	173	**1.78**	463	**4.25**	692	**7.27**

Table 7-13 summarizes the voltage sag contributions from each voltage system for each of the four sag magnitude ranges. These are the same contributions from Table 7-9 through Table 7-12. Row totals in Table 7-13 give the total number of sag events per year for each sag magnitude range.

Table 7-14 and Figure 7-13 are the final products of the magnitude prediction effort. They compare the number of nuisance sag outages for various equipment sensitivity levels. The predictions assume the pre-sag voltage is exactly the equipment nominal voltage and must be modified if the pre-sag voltage is different. Note that distribution system faults, often the major contributor to voltage sags frequency, are not included in this example.

Table 7-13—Summary of contributions from each system

Lowest phase per unit voltage range	Contribution by line voltage (number of events per year)				Totals
	345 kV	230 kV	138 kV	69 kV	
0 to 0.60	0.00	0.00	0.16	0.80	0.97
0.60 to 0.75	0.00	0.00	2.13	1.78	3.89
0.75 to 0.85	0.48	0.00	2.38	4.25	7.12
0.85 to 0.90	1.49	0.01	2.30	7.27	11.09

Table 7-14—Example number of sag problems depending on equipment sensitivity

Undervoltage threshold per unit	Voltage sags causing trip-outs in each range				
	0 to 0.60	0.60 to 0.75	0.75 to 0.85	0.85 to 0.90	Nuisance trip-outs per year
0.60	0.97	No trip	No trip	No trip	0.97
0.75	0.97	3.89	No trip	No trip	4.86
0.85	0.97	3.89	7.12	No trip	11.98
0.90	0.97	3.89	7.12	11.09	23.07

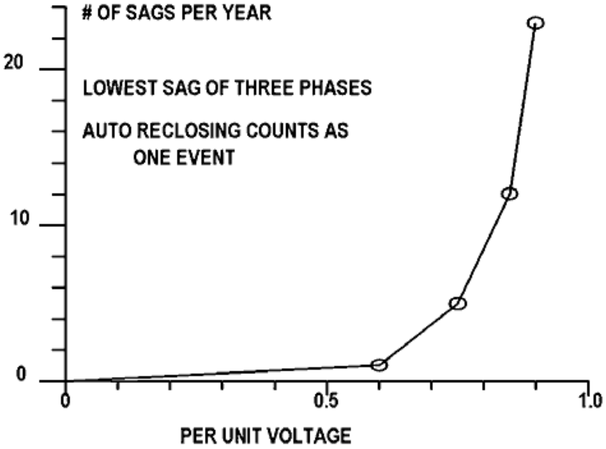

Figure 7-13—Number of sags from transmission network example

This particular study was recalculated for a different configuration to compare sag performance of alternative supplies. This allowed designers to compare the cost of the alternative supply configuration to the value of fewer sag problems. It also allowed plant designers to reasonably estimate the value of improving equipment immunity to sags.

A comparison of predicted voltage sags with system monitoring results is presented in Sikes [B28]. Although the 10-month period of single site monitoring was very limited, the study suggests that, while the relative frequency of different sag magnitudes was in line with prediction, and with Figure 7-8, the predicted sag counts can be significantly in error without a model calibration by comparison with monitoring data.

7.8 Nonrectangular sags

Previous parts of this chapter assume the rms sag magnitude vs. time is rectangular. This is not true when a large part of the load consists of rotating machines such as induction motors, synchronous motors, and generators. Examples are chemical plants and residential areas with mainly air conditioner load. The induction motors will somewhat moderate the voltage sag as they contribute current to the short circuit.

7.8.1 Induction motor influence on sag shape

Motors will slow down during a sag and reaccelerate when the system fault clears. The reacceleration may cause an extended post-fault sag if the motor load is large with respect to the system impedance. The post-fault sag can last up to several seconds and the voltage will be between 60% and 90%. Severe post-fault voltage sags can cause tripping of equipment that survived during the fault portion of the sag. This subclause concentrates on induction motors, as they form the bulk of the motor load. Synchronous motors show behavior that can be incorporated in a voltage sag study in a similar way. Power electronics controlled motor drives may show a very different behavior.

Figure 7-14 and Figure 7-15 show the voltage during and after a short circuit close to the PCC. Figure 7-14 gives the time-domain voltages calculated by using Electro Magnetic Transients Program (EMTP, which employs the full Park's equations for the induction machine). Figure 7-15 gives the amplitude of the voltage phasor, as calculated by a transient stability program (which employs a simplified induction motor model). What basically happens is that the induction motors slow down during the fault (the contribution of them to the fault current leads to the nonzero during-fault voltage) and reaccelerate after the fault has been cleared. The latter demands a high current, which causes the post-fault sag (see Bollen [B3]).

Figure 7-16 shows a measured voltage sag with a considerable post-fault component (see Melhorn, Hofmann, and Samotyj [B24]), as does Figure 7-1. The resemblance to Figure 7-14 and Figure 7-15 suggests that there was a large induction motor load somewhere near the fault position.

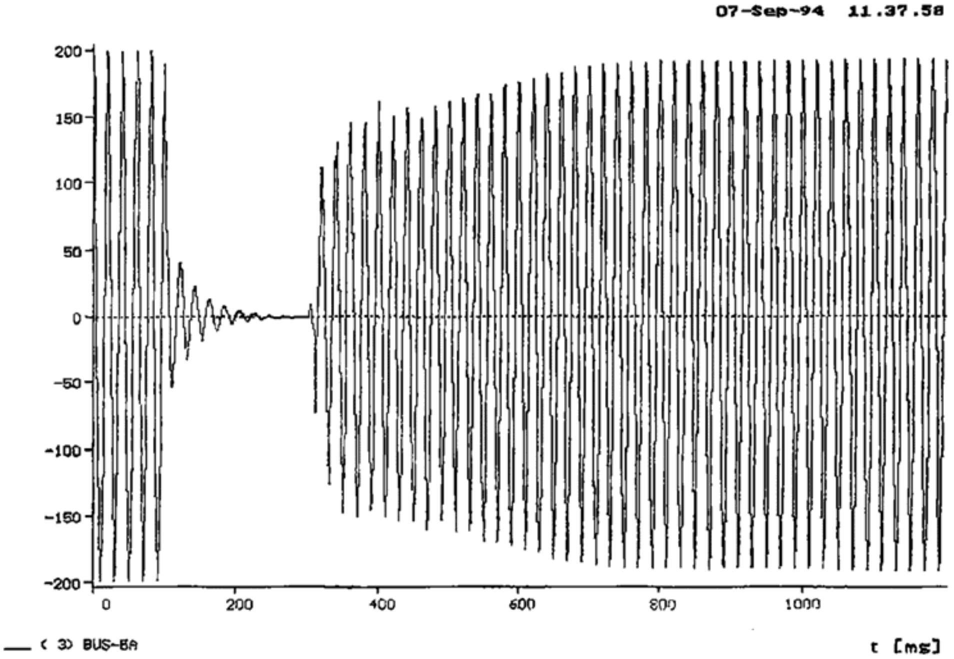

Figure 7-14—EMTP model of induction motor influence on a sag waveform

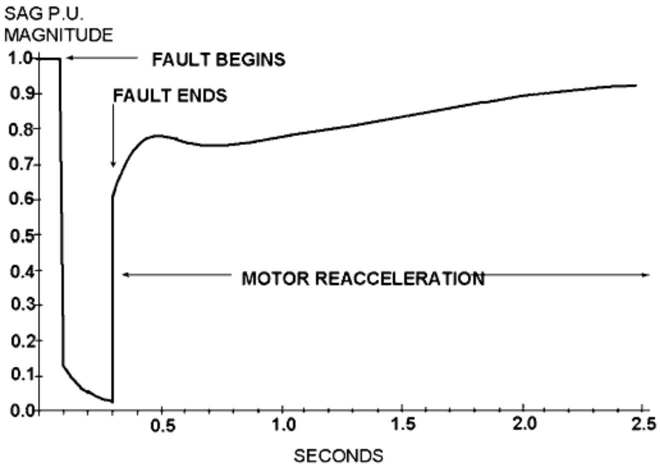

Figure 7-15—RMS voltage of EMTP model of induction motor influence on sag

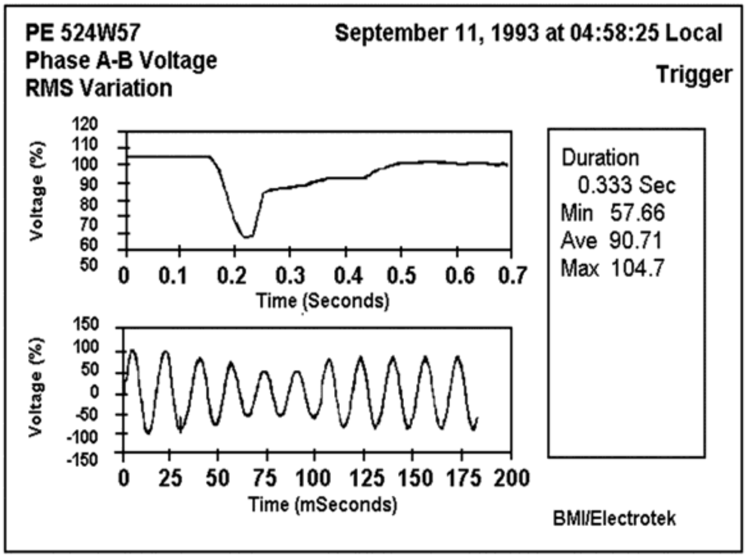

Figure 7-16—Typical waveform and rms plot showing motor influence

7.8.2 Stochastic assessment

In case the induction motor load significantly influences the shape of the voltage sag, more complicated calculations are needed than provided in 7.5 and 7.6. The type of induction motor model to be used depends on the accuracy required and the availability of software. In the forthcoming example, a transient stability program is used to calculate the shape of individual voltage sags.

As in 7.5.3, one has to select the fault positions that are expected to cause a significant voltage sag. Apart from the selection criteria mentioned before, the following can be used:

a) The post-fault voltage sag is more severe if the fault is near a concentration of induction motor load.

b) The post-fault voltage sag is more severe if part of the supply to the sensitive load is removed by the protection without removing any induction motor load.

c) The post-fault voltage sag is more severe for induction motor load with small slip and with very low or very large inertia constants.

d) The post-fault voltage sag is more severe for longer fault-clearing time.

It is, in theory, still possible to calculate a "duration" and a "depth" for a nonrectangular sag, e.g., by taking the time below 90% voltage and the average depth. An alternative presented here is to assume the equipment sensitivity to be rectangular and to determine the expected number of sags per year that cause the equipment to trip, for various equipment sensitivities. The result is shown in Table 7-15.

The voltage sag shape has been calculated for about 40 fault positions in the distribution system to a large chemical complex. The load consists mainly of induction motors. A transient stability program has been used to calculate the shape of the voltage sags, like in Figure 7-15. Table 7-15 shows that 0.168 times per year (i.e., once every 6 years), a situation occurs where the plant voltage is below 80% for more than 500 ms. So if the equipment in the plant can withstand an 80% voltage for up to 500 ms, an interruption of plant operation is expected to occur once every 6 years.

Table 7-15—Expected number of sags including effect of motors

Magnitude (%)	Duration				
	250 ms	500 ms	750 ms	1000 ms	1250 ms
90	0.506	0.444	0.168	0.044	0.024
85	0.461	0.438	0.046	0.024	0.024
80	0.446	0.168	0.026	0.024	0.004
75	0.174	0.024	0.024	0.004	0.004
70	0.032	0.004	0.004	0.004	—

7.8.3 Other types of load

The previous discussion concentrated on induction motor load. Other loads can be incorporated in the study in a similar way. The model that has to be used depends on the type of load.

All motor load (induction, synchronous, or fed through a power electronics drive) will suffer from loss of kinetic energy during a voltage sag (i.e., the motor will slow down). After the fault this lost energy will have to be recovered, which in almost all circumstances will lead to a post-fault voltage sag. Modern power-electronics drives with unity power factor will mitigate the effect, as will load shedding (either intentional or because of the erroneous tripping of equipment due to the sag). If a large fraction of motors is equipped with contactors that trip during the fault and come back all at the same time, the post-fault sag is simply postponed. If the contactors come back with different delay times, the post-fault sag will be considerably more shallow.

Nonmotor equipment might also cause a post-fault sag. Virtually all equipment shows capacitive behavior on a short timescale. Often there is even a physical capacitor present. As more and more equipment has large capacitors to ride through the sag, the post-fault sag will become more severe.

A problem with taking the post-fault sag into account is that the load composition is often not known. This holds especially for public supply systems. In that case, observation of voltage sag monitoring waveforms will indicate the level of motor loads connected within the critical distance from sensitive loads.

7.9 Development of voltage sag coordination charts

Sag coordination charts show electric supply sag characteristics and utilization equipment response to voltage sags on a single graphical display. The foundation for the display is the magnitude-duration chart described in 7.2.7. In the method proposed here, a family of contour lines shows the electric supply sag characteristics. Each contour line represents a number of sags per year.

An equipment line on the same chart shows the equipment voltage tolerance. Proper use of the sag coordination chart enables the estimation of the number of utilization equipment disruptions per unit of time due to voltage sags.

Two data sets are critical for the coordination effort. First, the electric supply sag characteristics must either be known from monitoring data or predicted. Second, utilization equipment response to sags must be known either from manufacturer specifications or from performance test data. Both supply characteristics and equipment response data sets are required to perform this coordination effort.

7.9.1 Electric supply sag characteristics display

The display of supply characteristics requires either historical or predicted sag magnitudes and durations. This data fills magnitude and duration bins in a computer spreadsheet for graphical presentation as contour lines. A very simple example will show fundamental concepts. Later, measured data from the Electric Power Research Institute (EPRI) Distribution Power Quality (DPQ) project will be used for a typical performance chart (see Wagner, Andreshak, and Staniak [B29]).

Table 7-16 shows a grid of nine sag magnitude ranges in rows, and five sag duration ranges in columns. The combination of nine rows and five columns produce a total of 45 magnitude-duration bins. Every measured or predicted sag will have a magnitude and duration that fits into only one of the 45 bins. The number of bins may vary depending on coordination needs for a particular case. However, this selection of 45 bins is reasonably convenient.

For a simple example, assume each of the 45 bins has one sag per year. Table 7-16 shows the one sag per year in each of the 45 bins. This means there are 45 sags per year, and the characteristics of each sag fit in a unique bin. The 15 bins in the lower right corner are shaded to promote understanding as this example continues.

Table 7-16—Count of events in each bin

Magnitude bin (%)	**Time bin (in seconds)**				
	0.0 to (<0.2)	**0.2 to (<0.4)**	**0.4 to (<0.6)**	**0.6 to (<0.8)**	**≥ 0.8**
(>80) to 90	1	1	1	1	1
(>70) to 80	1	1	1	1	1
(>60) to 70	1	1	1	1	1
(>50) to 60	1	1	1	1	1
(>40) to 50	1	1	**1**	**1**	**1**
(>30) to 40	1	1	**1**	**1**	**1**
(>20) to 30	1	1	**1**	**1**	**1**
(>10) to 20	1	1	**1**	**1**	**1**
0 to 10	1	1	**1**	**1**	**1**

Table 7-17 shows the cumulative number of sag events that are worse than or equal to each bin from Table 7-16. “Worse than” means the magnitude is lower and the duration is longer. The row and column headings only show single values instead of ranges. For example, there are 15 sags in the 50% magnitude, 0.4 s entry, of Table 7-17. The shaded number 15 in Table 7-17 is the sum of all 15 individual shaded entries in Table 7-16. This means 15 sags will have a magnitude of less than or equal to 50% and a duration longer than 0.4 s.

Table 7-17—Sum of events worse than or equal to each magnitude and duration

Magnitude (%)	Time (in seconds)				
	0.0	**0.2**	**0.4**	**0.6**	**0.8**
90	45	36	27	18	9
80	40	32	24	16	8
70	35	28	21	14	7
60	30	24	18	12	6
50	25	20	**15**	10	5
40	20	16	12	8	4
30	15	12	9	6	3
20	10	8	6	4	2
10	5	4	3	2	1

The next step converts Table 7-17 to a set of contour lines similar to elevation contour lines on a topographic map. Figure 7-17 is the contour plot of Table 7-17 generated by a computer spreadsheet and graphics program. The lines from lower left to upper right represent the number of sag events per year. Each contour line has a label for the number of events.

Continuing the simple example, the 15-event contour line intersects the 0.4 s axis at the 50% magnitude axis. This means 15 sags will have a 0.4 s or longer duration and have a 50% or lower magnitude. The dots on the lower right corner of Figure 7-17 show each of the 15 individual sags. Each dot represents the one sag event in each bin of Table 7-16 for this example. There are 15 dots in the rectangular area below and right of the contour line. Similarly, the 20 sag contour shows 20 sags worse than or equal to 0.2 s and 50% magnitude. Normally, the dots will not appear on sag coordination charts. Also, the actual sags will be somewhere in the stated range and not directly on the axis.

Linear interpolation between contour lines and axis works reasonably well, especially in this case, where the sags are distributed uniformly. For example, about 32 sags will be worse than or equal to 0.2 s and 80% magnitude on Figure 7-17. Also, 25 sags will be worse than about 0.28 s and 70% magnitude on Figure 7-17.

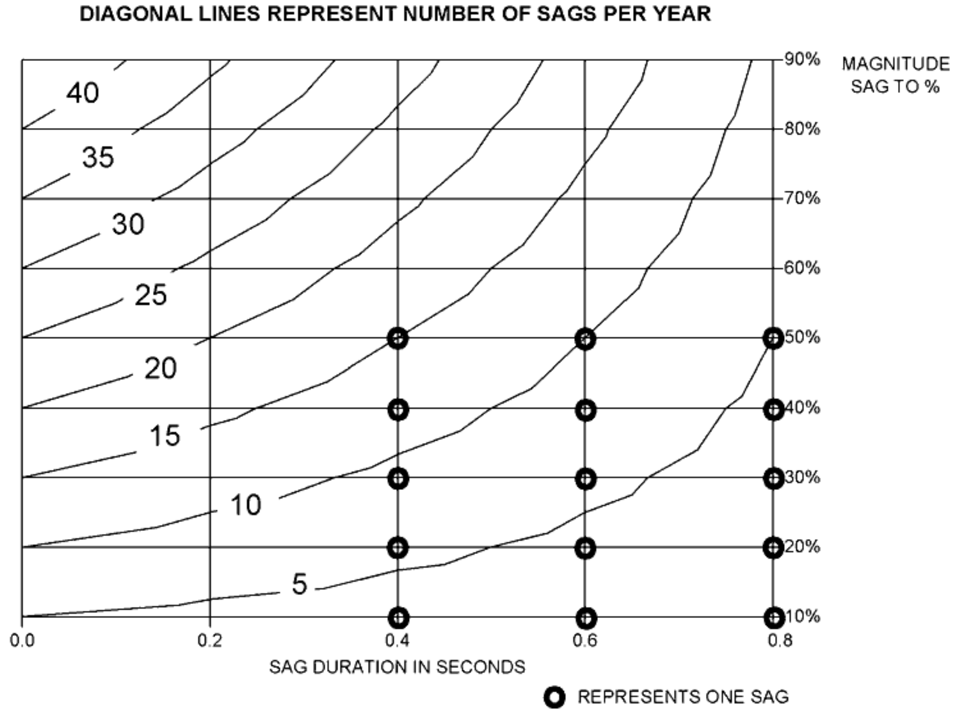

Figure 7-17—Supply sag performance contours and partial mapping of individual points

7.9.2 Adding rectangular equipment sensitivity

The equipment sensitivity curve (or *voltage tolerance curve*) describes the equipment sensitivity to voltage sags. This curve gives the minimum magnitude that the equipment can withstand for a given sag duration. This curve can be obtained from the equipment manufacturer, from equipment testing, from equipment simulation or, in the future, possibly from standards with typical equipment voltage tolerance. Example sensitivity curves for several types of equipment are given in IEEE Std 1346. Several publications show measured voltage tolerance curves. It appears that a rectangular curve is very common. The sag contour line method works very easily with these rectangular sensitivity curves. Figure 7-18 overlays the utilization equipment sensitivity on the sag contour lines. The sensitivity curve is typically rectangular or may be approximated with several rectangles. The shaded region shows the magnitudes and durations of sags that will cause disruption. The intersection of the rectangular sensitivity knee and the contour line gives the number of disruption events from sags. Continuing the simple example in Figure 7-18, the knee of the sensitivity intersects the 15 sag contour line. This means there will be 15 process disruptions per year.

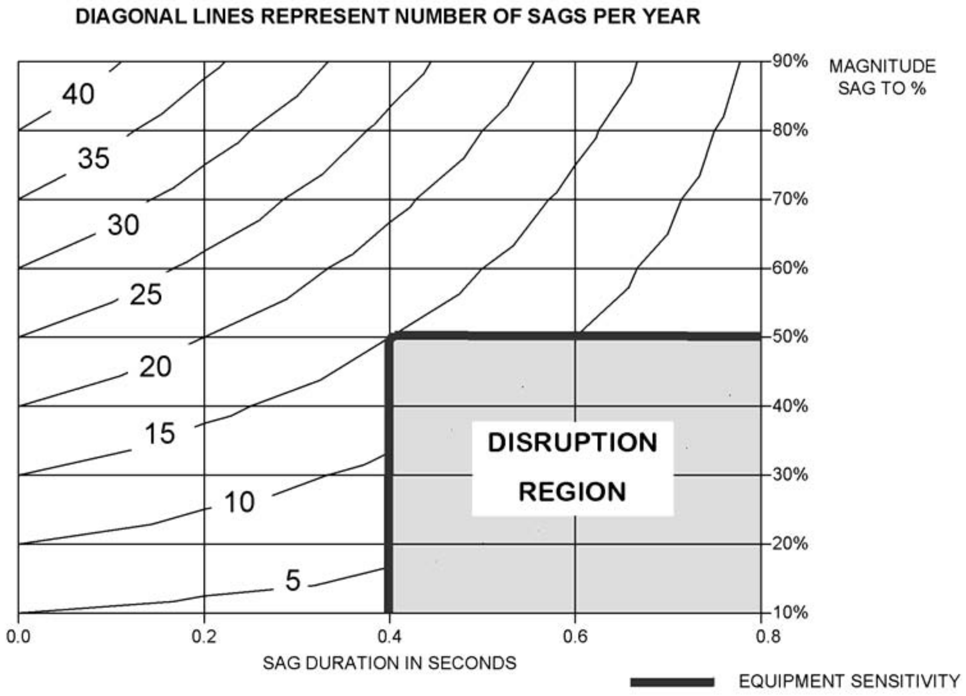

Figure 7-18—Supply sag performance contours and equipment sensitivity

7.9.3 Nonrectangular equipment sensitivity

The previous analysis assumes the equipment sensitivity has a rectangular shape. Nonrectangular sensitivity curves require a little more effort. They have to be approximated through a number of rectangular steps. Consider Figure 7-19 as an example. The equipment sensitivity is characterized or approximated by a shape with two knees. The disruption region is the combination of all three shaded rectangular areas A, B, and C. Knee #1 is positioned on the 20 sags contour line. Knee #2 of the sensitivity curve is at about the 24-sag contour line using linear interpolation. A third “knee” for area C is at the 15-sag contour.

The curve with only knee #1 is rectangular consisting of area B and area C. Equipment with such a curve would trip for 20 sags. Likewise, area A and area C (knee #2) represent equipment that would trip 24 sags. Notice that area C is shared by both knees. Simply adding the sags for knee #1 and knee #2 would overestimate the total sags by double counting area C. The mathematics to avoid double counting are shown in Equation (7.10), Equation (7.11), Equation (7.12), and Equation (7.13).

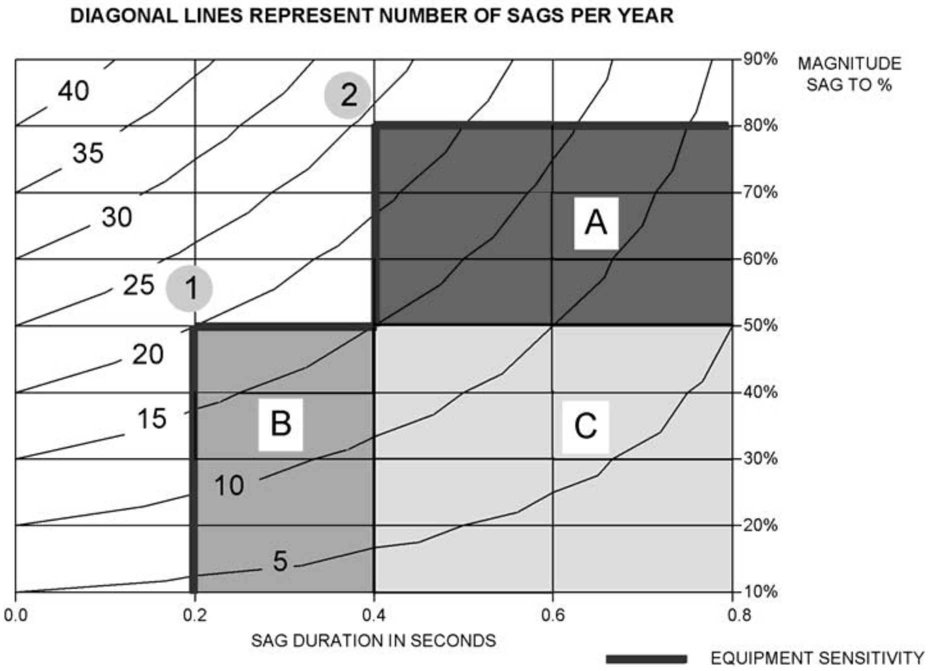

Figure 7-19—Approximation of nonrectangular sensitivity curves

$$\text{Total number of sags} = \text{area A} + \text{area B} + \text{area C} \tag{7.10}$$

For knee #1, there are 20 sags. Therefore

$$B + C = 20 \tag{7.11}$$

For knee #2, interpolation is required. Interpolation gives about 24 sags. Therefore

$$A + C = 24 \tag{7.12}$$

Area C represents 15 sags. Thus C = 15. With Equation (7.11) and Equation (7.12), it is now easy to find that A = 9 and B = 5.

Substituting the values A = 9, B = 5, and C = 15 in Equation (7.10) gives the total number of sags:

$$A + B + C = 9 + 5 + 15 = 29 \text{ disrupting sags} \tag{7.13}$$

Thus, the sag coordination chart predicts 29 disruptions per year for this nonrectangular equipment sensitivity. A simple counting effort on Figure 7-19 (as with the dots in Figure 7-17 confirms the 29 disruptions. (It is also possible to overlay the equipment sensitivity over Table 7-16 and total the sags for a similar result.)

7.9.4 Example of system performance using typical measured data

The following example develops the supply system sag performance based on data supplied by the EPRI's DPQ project (Wagner, Andreshak, and Staniak [B29]). The data represents 222 distribution feeders in the U.S. from 1 June 1993 to 1 June 1994. This example develops exactly in the same manner as the simple example shown earlier.

Table 7-18 shows the number of sags per year per site as a function of magnitude and duration. For example, there were 6.8 sags per site per year with magnitudes between 60% and 70% and durations of less than 200 ms.

Table 7-18—Sample data from DPQ project: number of events per year

Magnitude bin (%)	Time bin (in seconds)				
	0.0 to (<0.2)	0.2 to (<0.4)	0.4 to (<0.6)	0.6 to (<0.8)	≥ 0.8
(>80) to 90	53.1	4.8	1.9	0.7	2.9
(>70) to 80	14.1	1.7	0.2	0.2	0.4
(>60) to 70	6.8	0.9	0.1	0.1	0.2
(>50) to 60	3.5	0.9	0.2	0.0	0.2
(>40) to 50	1.4	0.4	0.2	0.0	0.3
(>30) to 40	1.5	0.1	0.1	0.0	0.3
(>20) to 30	1.2	0.3	0.2	0.2	0.4
(>10) to 20	1.0	0.1	0.0	0.0	0.5
0 to 10	1.9	0.7	0.7	0.2	6.4

Table 7-19 presents the total sags worse than or equal to the magnitude and duration headings. For example, there were 16.3 sags to 80% or lower lasting 0.2 s or longer per site per year.

Figure 7-20 shows the supply system sag performance contours over the one year of measurements.

For the equipment tolerance curve in Figure 7-18 one can now expect about nine spurious trips per year for the supply characterized in Figure 7-20. (From Table 7-19, a value of 9.4 is found.) For the equipment tolerance curve in Figure 7-19, the expected number of spurious trips is about 12 + 13 – 9 = 16. (From Table 7-19, a value of 10.9 + 11.2 – 9.4 = 12.7 is found.)

It might appear here that Table 7-19 gives more accurate results than the sag coordination chart in Figure 7-20. One should remember that this kind of accuracy in monitoring results is rare, that the difference is not significant from a stochastic point of view, and that a more dense set of contours in Figure 7-20 would give more "accurate" results from there as well.

Table 7-19—DPQ example: Sum of events worse than or equal to magnitude and duration

Magnitude (%)	Time (in seconds)				
	0.0	0.2	0.4	0.6	0.8
90	111.2	26.7	16.8	13.2	11.7
80	47.8	16.3	11.2	9.6	8.8
70	31.0	13.7	10.4	8.9	8.4
60	22.9	12.4	9.9	8.6	8.2
50	17.9	10.9	9.4	8.3	7.9
40	15.7	10.0	8.9	8.0	7.6
30	13.6	9.5	8.5	7.7	7.3
20	11.4	8.5	7.7	7.1	6.9
10	9.8	7.9	7.2	6.6	6.4

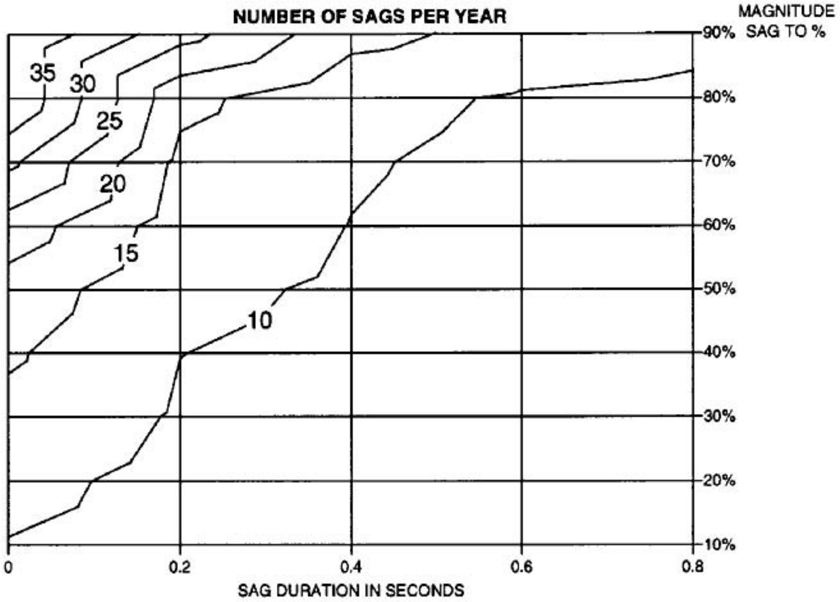

Figure 7-20—Sags per year for 222 DPQ project sites from 1 June 1993 to 1 June 1994

7.10 Voltage sags monitoring surveys

The historical prevalence of voltage sags at industrial sites has been captured in several voltage monitoring surveys (see Conrad, Grigg, and Little [B5], Dorr [B7], Goldstein and Speranza [B9], and Gulachenski [B10], Koval et al. [B23], Sabin, Grebe, and Sundaram [B26]). Survey results from the early 1990s are summarized by Dorr et al. [B8].

Most studies have surveyed end-user point-of-use locations, which are most often connected to the distribution grid. These sites often share a distribution feeder with many other utility customers, and share a distribution substation bus with yet more customers; consequently, the probability of a distribution level fault is higher than for a site with a dedicated substation. Table 7-13 shows that voltage sags caused by transmission or subtransmission faults are several times more likely at 69 kV than at 345 kV. On radial distribution feeders, the number of sags is several times more likely yet (see, for instance, the CEA primary vs. secondary monitoring results in Dorr et al. [B8]).

Further, monitoring at the customer service entrance, as opposed to the distribution feeder, will include both power system fault sags and facility fault sags. Because of the relatively high service entrance transformer impedances, faults within a low-voltage customer facility are typically not reflected significantly onto the distribution feeder.

Seasonal and yearly variation in voltage sags frequency can be significant, being greatly dependent on weather and other stochastic events. Figure 7-21 shows the monthly variation in voltage sags frequency recorded at the MV service entrance of one industrial facility in the US over a 3-year period.

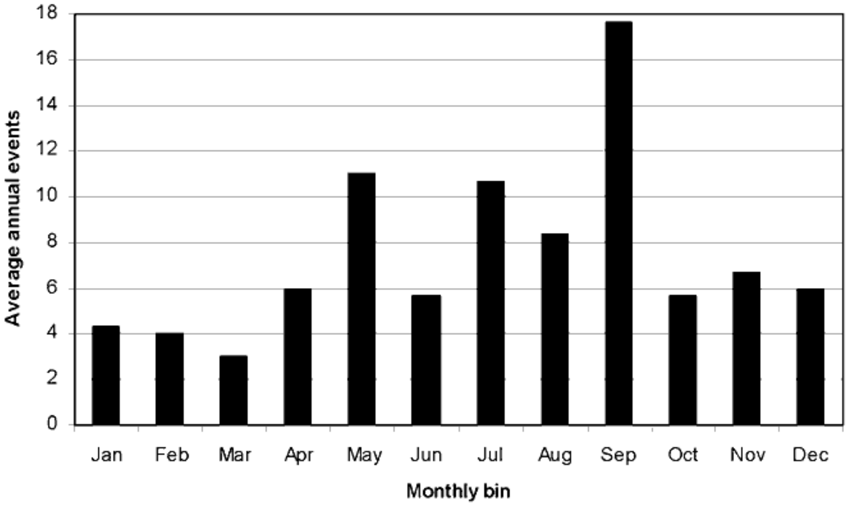

Figure 7-21—Seasonal variation of average sags per month (2 min temporal aggregation)

7.11 Economic costs of voltage sags

The methods of 3.4 for computing the cost of service interruptions can be equally well applied to process interruptions caused by voltage sags and momentary interruptions. However, because voltage sags are often not readily perceptible, the cause of process shutdown may not be correctly ascribed in process logs unless automatic voltage monitoring devices are in place. A method to evaluate and analyze the financial impact of voltage sags is provided in IEEE Std 1346.

7.12 Conclusions and future work

By the very nature of utility transmission and distribution networks, voltage sags occur much more frequently than sustained interruptions and likewise cause unplanned equipment downtime at a higher rate. The method for voltage sag coordination described in this chapter is an important tool in the power quality field. The procedure enables customers, utilities, and equipment manufacturers to quantify the performance of their process, supply, or device. This will no doubt lead to a better understanding of spurious trips and an improvement in performance. Ready access to the data needed for these assessments is not generally available, however. Industrial and commercial electricity consumers will need to request reliability and fault frequency data from utility providers to accurately predict voltage sag characteristics and must specifically request voltage sag tolerance data from equipment suppliers.

Still, the method as presented here has its limitations. The main assumption is that a voltage sag can be characterized through one duration and one magnitude and that this magnitude and duration uniquely determine the equipment behavior. Unfortunately this is not always the case; 7.2 already mentioned some of the confusion in characterizing the sag. Aspects that could influence equipment behavior are the point-on-wave of fault initiation; the phase-angle jump in the voltage associated with a sag; the imbalance between the three phases for three-phase equipment; the long post-fault sag due to inrush in heavily loaded systems; the post-fault overvoltage when faults are cleared by current-limiting circuit breakers or fuses; and the variation in equipment tolerance over the production or loading cycle.

Each factor will have to be evaluated to determine its influence on equipment. If the influence is likely to be significant, assessment methods will have to be developed and the coordination method described in this chapter will have to be extended.

The method has thus far only been concerned with voltage sags. Other voltage disturbances can be included easily as long as they are characterized by a magnitude and a duration. For swells and momentary interruptions, this will be straightforward. For sustained interruptions the method presented here has limited value. The other chapters of this recommended practice discuss the methods for sustained interruptions. It is assumed that a disturbance either leads to an equipment trip or not. Either this method can be extended or one of the many existing methods can be used for sustained interruptions.

7.13 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 1159, IEEE Recommended Practice for Monitoring Electric Power Quality.[3, 4]

IEEE Std 1346, IEEE Recommended Practice for Evaluating Electric Power System Compatibility with Electronic Process Equipment.

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[4] The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

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[B12] IEC 61000-4-11:2004, Electromagnetic compatibility (EMC)—Part 4-11: Testing and measurement techniques—Voltage dips, short interruptions, and voltage variations immunity tests.

[B13] IEC 61000-4-30:2006, Electromagnetic compatibility (EMC)—Part 4-30: Testing and measurement techniques—quality measurement methods.

[B14] IEC 61000-4-34:2005, Electromagnetic compatibility (EMC)—Part 4-34: Testing and measurement techniques—Voltage dips, short interruptions and voltage variations immunity tests for equipment with input current more than 16 A per phase.

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Chapter 8
7 × 24 continuous power facilities

8.1 Introduction

The explosive growth of computer technology has literally changed the way business is conducted. Cell phones, pagers, fax machines, and e-mail have become the norm and the Internet provides a communication medium not previously available. Stock trading and banking, along with an incredible diversity of retail sales, occur daily via the Internet.

With the broad expansion of computer technology comes the necessity of providing an infrastructure capable of supporting it. The ITIC susceptibility curve, as shown in Figure 7-2, shows that electronic equipment can be disrupted by a momentary sag of from 4 ms to 20 ms. Momentary interruptions of the electrical power can have huge financial consequences. Therefore, specialty equipment, such as uninterruptible power supplies (UPS), emergency generators, and automatic static transfer switches (ASTSs) are used to supplement utility power.

Initially, special facilities were designed for mainframe computers, used primarily for banking and finance, called *data centers*. As the use of computers broadened and support of the Internet became a significant market, along with divestiture of the telecommunications industry, the term *7 × 24 facility* became common. This term is derived from the requirement that the facility operates 7 days a week, 24 hours per day. Another common name for facilities designed to support electronic equipment in continuous operation is *mission critical facilities®*.[1]

8.2 Special equipment to support continuous operation

There are several special pieces of equipment specifically designed to support the continuous power requirement of electronic equipment. The most common is a UPS. In the critical facility environment, the majority of UPS is "double conversion," where ac power is converted to dc with a rectifier, and then back to ac by an inverter. Batteries provide backup power to the inverter, on loss of power to the rectifier.

There are other UPS designs than double conversion, such as standby (line interactive) and off-line. In a standby (line interactive) UPS, the inverter is operating but not carrying load unless utility power is lost. For an off-line UPS, the inverter does not start until the utility power is lost. There are also rotary UPS systems that employ synchronous generators instead of inverters for the output power.

Another very common piece of equipment is a static bypass switch. This is an electronic switch capable of shunting power around the UPS on loss of inverter output. Many static bypass switches detect the loss of power and operate within a 1/4 cycle. They can be built

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[1] *Mission critical facilities* is a registered trademark of EYP Mission Critical Facilities, Inc.

into the UPS module itself, or as a separate part the control cabinet for multi-module UPS configurations.

In Figure 8-1, the static bypass switch is internal to the UPS module. Figure 8-5 shows a parallel redundant configuration of UPS modules with an external static bypass switch.

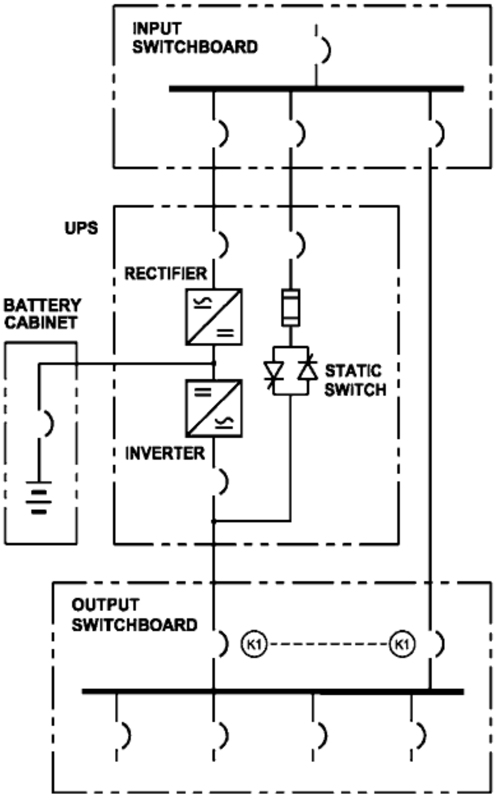

Figure 8-1—Double conversion UPS module with internal static bypass switch

In recent years, the same technology used for a static bypass switch has been applied to other transfer switches. An ASTS, shown in Figure 8-2, operates in a similar way to two static bypass switches supplying a common load. Typically, power is brought to each side of the ASTS from a different UPS. For a voltage deviation outside the specified limits on the "primary" side, it switches to the "alternate," often within a 1/4 cycle.

There is a significant difference between the control of the static bypass switch and the static switch of an ASTS. The static bypass switch is fired so that it "makes" (provides a closed transition) before the UPS inverter is shut down. The ASTS does the opposite. It opens one static switch as it transfers and then closes the other static switch (open transition). It is very important that the ASTS operate as an open transition, as one of the worst failure modes of an ASTS is a "cross-connection" in which both static switches are closed at the same time and thus both power sources are connected together.

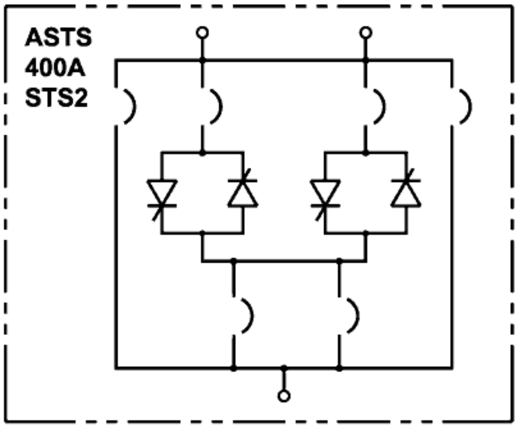

Figure 8-2—Automatic static transfer switch

ASTSs can be relatively large, such as 600 A, in which they supply power to the entire power distribution unit (PDU). They are also made in smaller sizes to be mounted right on the rack with the information technology (IT) equipment itself.

The ASTS can also be used on the primary (480 V) or secondary side (120/208 V) of the PDU transformer. To install the ASTS on the secondary side, two transformers are required. Though it has a higher initial cost, it is the preferred method for two reasons. The first reason is it eliminates the significant problem of transformer inrush current during an out-of-phase transfer. The second transformer is already energized by the alternate source and therefore does not have to be reenergized while it still has a residual magnetic field from the first source (as it does in the case of a transformer with the ASTS on the primary side). The second reason is it is more reliable, since the transformer has been eliminated as a single point of failure (SPOF).

The PDU shown in Figure 8-3 consists of a transformer, distribution panel(s) with circuit breakers to supply the critical loads, and usually some form of built-in power monitoring. The transformer may be shielded, a K-factor transformer, or both. Some manufacturers of PDUs also provide surge protection in the unit.

One of the most significant advances, from a reliability standpoint, is the development of dual-corded IT equipment. Dual-corded IT equipment has two power supplies built into it, with two separate power cords, each capable of powering the equipment. This provides the opportunity to eliminate single points of failure from the power source all the way to the piece of IT equipment itself. For many designs, the availability improves by an order of magnitude (factor of 10) in comparisons between single- and dual-corded equipment.

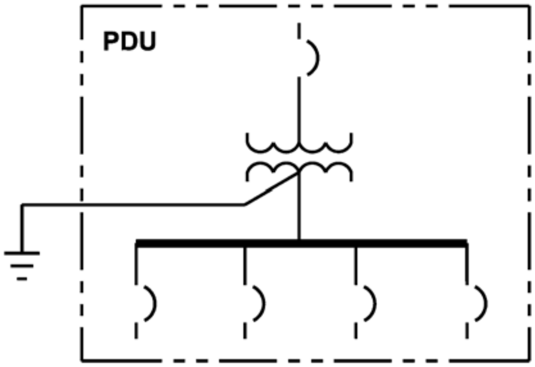

Figure 8-3—Power distribution unit

However, for IT equipment with dual-cord powers to actually achieve the predicted availability and reliability, it is very important that the IT equipment provide notification when one of the power supplies fails. Otherwise, the latent failure of the power supply will only be discovered when the power supply is needed and the equipment goes down.

Dual-cord power supplies come in two basic types, one type that utilizes regulated power supplies where one side takes 100% power and the other that uses unregulated power supplies with current sharing onto a common dc bus. The unregulated power supplies each take 50% of the load.

There are also IT equipment designs in which more than two power supplies are used, such as three out of four or four out of five designs. For these equipment designs, the manufacturer usually provides an option that powers the multiple power supplies from two power cords, with some form of internal switching.

8.3 Defining *failure* in a 7 × 24 facility

The first step of any probability analysis is to define the system to be analyzed. This includes determining what constitutes a failure. While it may seem obvious for simple systems, as the systems become interconnected, the line blurs. Take for example, a UPS with an internal static bypass switch. If the UPS module shuts down, but the static bypass switch carries the load, is that a failure? The UPS manufacturer will tell you, “No, the system worked exactly as it was designed to.” However the load is now exposed to the sags, etc., of utility power, which is exactly what the UPS was installed to protect against!

Another significant issue is what constitutes a failure at the individual critical load itself, usually some piece of computer or IT equipment. In a large data center there will be thousands of individual loads. There is usually redundancy for the computers or other IT equipment, and they often work in conjunction with each other. A majority of the time the interactions are so complex that it is not possible to determine with any degree of accuracy exactly which of the machines will take care of a specific application or data communication. Should the loss of one load constitute a failure? It may have no impact whatsoever to the overall mission of the facility.

Another aspect of this same issue is that in most critical facilities, there are multiple PDUs or UPS distribution panels in the facility. In each panel there are multiple branch circuits. If a failure was defined as the loss of an individual circuit, several factors would immediately be apparent. First of all, the type of system upstream of the panel would be relatively insignificant in the calculations, compared to the number and failure rate of the individual branch circuits. Secondly, the bigger the data center the worse the availability and reliability would be *regardless of the design*. Therefore, it does not make sense to go to the individual branch circuit level, as it skews the results based on size.

The effect of the size of the facility on the reliability and availability of the data center will be discussed in more detail in 8.5.2.

A third aspect of defining failure is, “What is the data to be used for?” There is no point in collecting vast quantities of data that is insignificant and obscures data that is significant. So it may be easier to “reverse engineer” the definition of failure, by looking at what would be significant data.

At this point in the chapter we are going to recommend definitions for failure of the various components, systems, and subsystems in a 7 × 24 facility. As the chapter progresses we will discuss why these particular definitions were selected, and also recommend what failure data to capture for the various components and subsystems.

8.3.1 Failure of components

Automatic static transfer switch—Failure to transfer or loss of power at the load terminals for any reason except no input power to either side of the switch.

Automatic transfer switches (mechanical)—Failure to transfer or loss of power at the load terminals for any reason except no input power to both inputs of the switch.

UPS battery—Loss of power to the inverter it is supplying, whether due to discharge, connections or internal cell failure.

Circuit breaker—Loss of power to the load it is feeding, regardless of where in the system it is located, except when a fault in the cables or equipment it is feeding caused the circuit breaker to open. It would also be a failure if the circuit breaker closed when it was not supposed to due to a defective control or part.

Generator—No output power when required.

NOTE—It is important to capture whether the generator failed to start, or whether it failed while operating, as will be discussed in more detail later. [2]

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[2] Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement the standard.

Static bypass switch (for UPS module)—Failure to transfer or loss of power at the output terminals for any reason except no input power to input of the switch (when called upon to be operated by either UPS module failure or manual switching operation).

UPS module rectifier—Failure to provide power at the dc bus, regardless of whether the battery is charged and providing power to the inverter, except when there is no power at the input of the rectifier, due to a failure upstream.

UPS module inverter—Loss of output power at the inverter in any failure mode except for loss of dc input (which is a battery or rectifier failure, not a UPS inverter failure).

NOTE—Whether or not a static bypass switch operates is inconsequential to the UPS module failure, though it would be very significant at the subsystem level.

8.3.2 Failure of the subsystem

UPS system (UPS module with static bypass switch, for single or multi-module system)—Loss of power to the load it is feeding, *including* momentary sags where the voltage disturbance is outside the specified limits, as the purpose of the UPS module was to protect against this in the first place. Therefore, it is a failure of the subsystem if there is a voltage disturbance outside the specified limits while the load is on the static bypass switch.

8.3.3 Critical system

At this point there has to be some discussion of what reliability and availability calculations will be used for to fully define a "failure" for the critical systems. The loss of power to a PDU (or UPS distribution panel) is the recommended definition of *failure* for most types of system calculations. In most data centers, the loss of an entire PDU would impact the overall mission of the facility. If the facility has dual-cord loads (computer or other IT equipment in which there are two power supplies internal to the equipment itself, and only one is required to power the equipment), it would be the loss of power to both PDUs (or distribution panels). This will be discussed in more detail in the following subclauses.

8.4 Reliability and availability as tools in evaluation of critical facilities

When evaluating the reliability of a system, the general rule is the fewer components there are that are required to operate the system, the more reliable it will be. This was probably first discovered in terms of "moving parts" for mechanical equipment. The more moving parts the piece of equipment has, the more opportunities there are that something will fail. In terms of the reliability analysis, each component can be considered a "link" in the overall reliability "chain."

Another general rule is that the reliability is improved by the elimination of "single points of failure." Each link of the reliability chain is an SPOF. Any one link can break and cause the chain to fail. However, if there are two chains, each one fully capable of carrying the load individually, all the single points of failure would be eliminated, dramatically raising the reliability of the overall system. This is also referred to as providing *redundancy*. The second chain is *redundant.*

Another aspect of eliminating single points of failure with redundancy is to eliminate the common mode events that could bring down both systems. A typical example is a redundant UPS module where the controls, output bus, output breaker, or the static bypass switch are common devices. A failure in one of the common devices can bring down the entire system in spite of the redundant UPS module.

8.4.1 Reliability and availability—Importance of using both

From looking at the definitions of *reliability* and *availability* in Chapter 2, there are some important differences between these two concepts. Reliability is time dependent. The longer the time, the lower the reliability, regardless of what the system design is. Availability is more or less independent of time, since it is the ratio of two means (averages). In the case of *inherent availability* (Ai), it is the mean time between failures (MTBF) divided by [MTBF + mean time to repair (MTTR)]. This encourages the use of availability when comparing system designs, and looking for an index of quality. Hence, terms such as “5-9’s” (meaning an Ai of 0.99999) have become common.

Availability can be a prediction of future performance or a measure of past success. In the case of past success, *achieved availability* is the percentage of time the system was operating. An availability of 0.99999 would mean that the system was down for 5.3 min or 315 s per year. It would make no difference in the availability calculation if there was one 5.3 min outage or 315 1 s outages. It could also be one outage of 1.77 h in 20 years. In all three cases, the availability is 0.99999.

To the operation of electronic equipment in a critical facility, there are huge differences between the three cases described, which is why reliability is a more important index. In the example of 315 1 s outages, the reliability for a one week period would be zero, since there is an average of 26 failures a month. For the example of 5.3 min once a year, the reliability would be significantly better, but still probably unacceptable for most critical facilities. However, for most critical facilities, a single outage of 1.77 h in a 20-year period would be an acceptable performance.

This discussion shows that availability by itself does not completely address how often a failure occurs. It is just a combination of how often it fails and how quickly it is repaired. Critical facilities require both high availability and high reliability.

In a utility distribution system, particularly in areas with overhead distribution lines, a high availability can often be achieved using reclosers. A very common scenario throughout the mid-western part of the U.S. is that a tree branch is blown into the power line during a storm. The recloser opens to clear the initial fault, then immediately recloses. The initial fault blew the tree branch to pieces, so the recloser restored the power. The total outage time could be a few seconds or less, and therefore the availability could be quite high. However, all the customers on the line downstream of the recloser would have experienced a momentary outage (and have to reset their electronic clocks).

With computer and other IT equipment, “repairing” the failure by getting power back does not restore the data that was being processed. Data is lost, the programs can also be corrupted, or the machine may not be successful in the rebooting process and require additional operator intervention. The explosive growth of the UPS industry paralleling the computer industry is testament to how important it is to provide continuous power, and avoid even very short outages of a few cycles.

8.4.2 Reliability and availability as tools in design evaluation vs. evaluation of the reliability of a specific facility

One of the most successful uses of reliability engineering is in evaluating and improving equipment design. Calculations can be performed for the component level, such as a UPS module, to improve its design. They can also be done as a comparative tool to evaluate how best to configure subsystems, such as multiple UPS modules. In each case, the purpose of the calculation impacts how the model is developed.

As mentioned earlier, the purpose of doing reliability analysis can be defeated by improperly modeling the equipment or system, e.g., modeling every PDU in a large facility and comparing it to a small facility with only a couple of PDUs. The small facility will have better reliability and availability numbers, just because there are fewer PDUs to fail. The large facility may actually have a much better design configuration with built-in redundancy, but appear to be much worse. In this case, a better comparison of the design for the two facilities would probably be gained by only using a few of the PDUs with the large facility.

Another significant factor that can utterly defeat the purpose is incorrect failure rate data. The best data would be the actual failure data of the facility. However, this is often not available, and published failure rate data is the best source of information. The published failure rate data for most of the electrical power equipment in this book is probably somewhat conservative for 7 × 24 facilities, since it comes from a broad cross section of facilities. Most 7 × 24 facilities are much a cleaner and more controlled environment than the average facility, particularly when compared to industrial sites.

However, the real issue with failure rates for a 7 × 24 facility is the shortage of statistically valid data for special equipment, such as UPS modules, ASTSs, etc. The vast majority of the data that is available comes from the manufacturer of the equipment. The obvious conflict of interest to show their equipment in its best possible light makes this source of information suspect. It is not uncommon for different manufacturers to use different failure criteria, which shows their equipment superior to their competition’s, when reporting equipment failure rates. The subclause earlier in this chapter defining failure for components and subsystems is an effort to at least standardize this aspect of the data collection.

A third factor that is an inherent limitation of any type of modeling is that someone has to make qualitative judgments as to what is significant and what is not. Therefore reliability models that compare one design to a similar design are usually of more value than models that try to predict the reliability and availability of a specific system.

As a comparative tool to analyze two similar designs, it is much easier to minimize the effects of these factors on the accuracy of reliability analysis. For example, the failure rates used in the calculations may be significantly higher or lower than the actual failure rates for a specific facility. Therefore the availability and reliability calculated would also be higher or lower than they really should be. However, when comparing two designs, the same failure rates would be used for both designs. Therefore the difference in availability and reliability for the two designs would be unchanged by the fact the actual failure rates for the facility were either higher or lower than what was used for the calculations.

8.5 Critical distribution system configurations

8.5.1 Common configurations of the UPS system

Momentary interruptions of the utility power are a very significant failure the critical load must be protected from. The simplest and most common UPS configuration is a single module with an internal static bypass switch. The critical load is protected from the momentary interruptions, along with complete outages by the energy stored, usually in batteries. If the UPS module fails, the static bypass switch transfers the critical load back onto utility power.

When the inverter of a single module UPS fails, the static bypass switch transfers the load to utility power. This exposes the critical load to momentary sags, which is what the UPS was installed to protect against in the first place. This led to the “isolated redundant” configuration, shown in Figure 8-4. In an isolated redundant UPS, the inverter of a second UPS module feeds the static bypass switch of the first module. Therefore, the static bypass switch transfers the critical load to a second UPS module instead of utility power.

A primary disadvantage of the isolated redundant configuration is the step loading of the second UPS module. The redundant module goes from no load, while the first module is in operation, to full load in a single step. This type of operation is difficult for a static UPS module to respond to and maintain the voltage within specified limits. Another disadvantage is that a fault on the output of the UPS module cascades from the first to the second UPS module, which can be a concern if there are separate power sources for the two UPS modules.

Shown in Figure 8-5, the parallel redundant configuration with a single static bypass switch was developed as a better configuration for utilization of the UPS modules. In a parallel redundant configuration, two (or more) UPS modules operate in parallel sharing the load. If one of the modules fails, the other module picks up the additional load. In the case of two identical UPS modules, each operates at half of their full-load rating; the step load is now half what an isolated redundant configuration would experience. For three identical UPS modules, with one as redundant, each module would carry 2/3 of full load, until one module failed. Then the remaining two would each pick up 1/3 of full load in a single step.

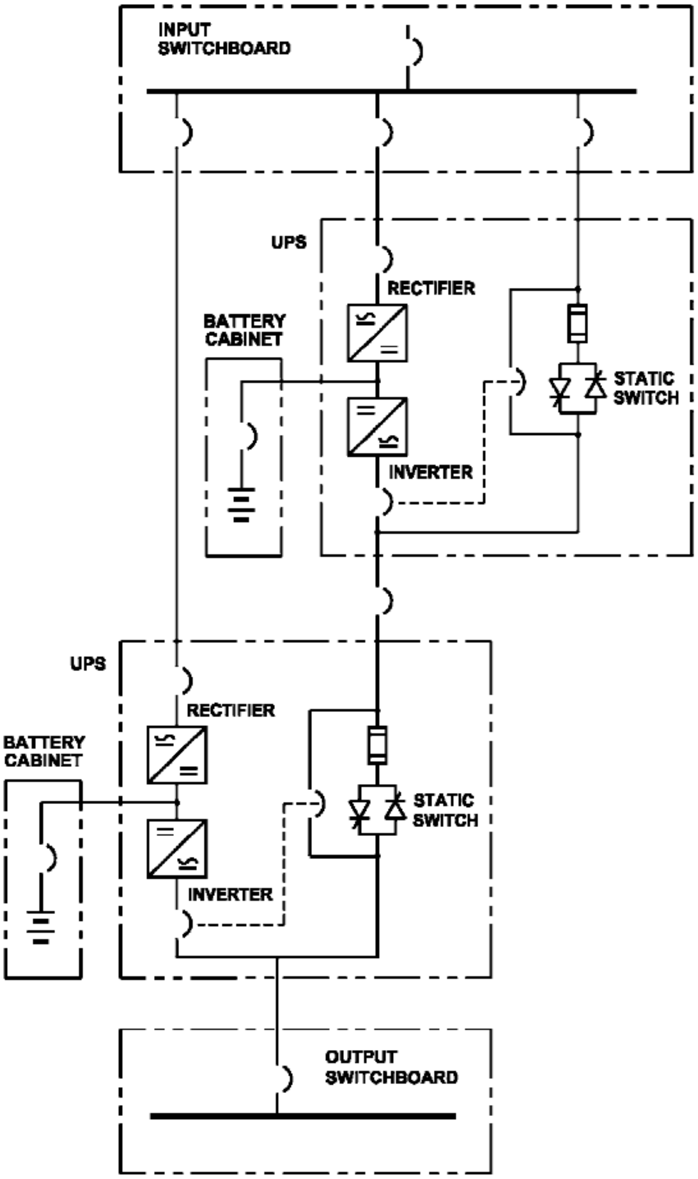

Figure 8-4—Isolated redundant UPS system

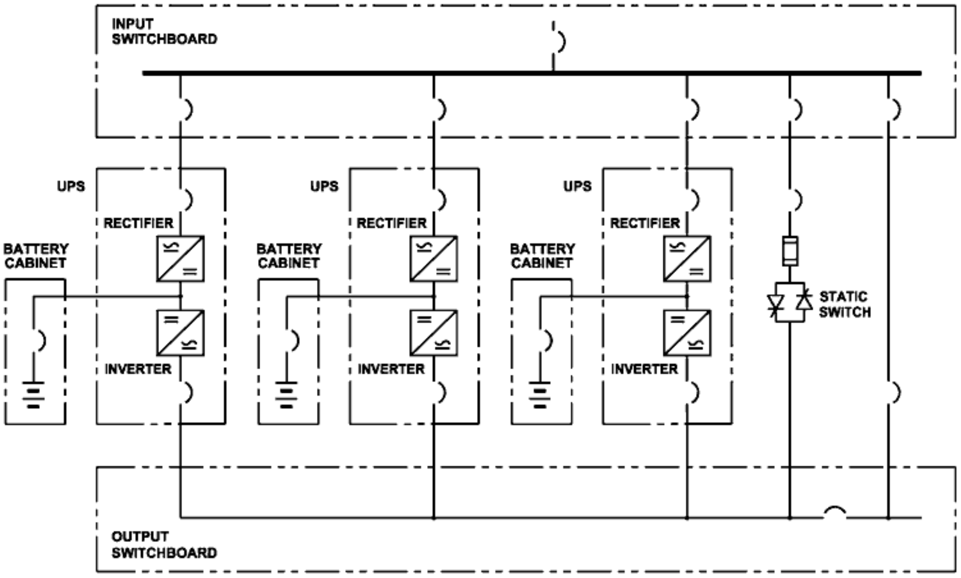

Figure 8-5—Parallel redundant—Three UPS modules with a system static bypass switch and maintenance bypass circuit breakers

These examples of three UPS modules in a parallel redundant configuration has a second advantage. Now each module operates at 2/3 of full-load rating, instead of 1/2. This is more efficient in terms of both energy usage and utilization of resources. However, a parallel redundant system requiring one out of two UPS modules will be more reliable than a similar system that requires two out of three UPS modules.

The main disadvantage of the parallel redundant configuration is the presence of several single points of failure (SPOF). The input and output switchboards are both SPOF, along with the static bypass switch and the system controls. A common example of the output as a SPOF is for an internal failure of a UPS module. This could result in the loss of the entire system, should the circuit breakers and UPS controls fail to isolate it quickly enough. A typical scenario starts with an output filter capacitor shorting. The remaining UPS modules feed the fault, and the output voltage begins to collapse. The UPS system controls sense the collapse in output voltage and turn on the static bypass switch, directly feeding the fault from the utility source. If the magnitude of the fault current is high enough to trip the breaker feeding the static bypass switch (or the ground fault on the main circuit breaker feeding the input switchboard), power is lost to the critical load.

8.5.2 Critical distribution system designs

A common aspect of many critical distribution systems is redundancy; there are more of key components than are necessary to carry the total load. The two most common key components to have redundancy are the UPS modules and the emergency generators.

When discussing redundancy of a system, it is common to refer to what is required as "N" (for *number*). If a facility has two standby generators, and both are required to carry the building load during a power outage, N is two. If a third generator was added, the redundancy of the power generating system would become "N + 1." There would also be 50% redundancy in standby generator power.

If the facility has two standby generators, and only one is required, the redundancy would also be called N + 1. This could also be called "2N," to show there is 100% redundancy in standby generator power. It depends on how the generators are configured to determine which term is preferred. If the generators are in parallel, as shown in Figure 8-6, it would be N + 1. If they are totally independent of one another, the redundancy is 2N.

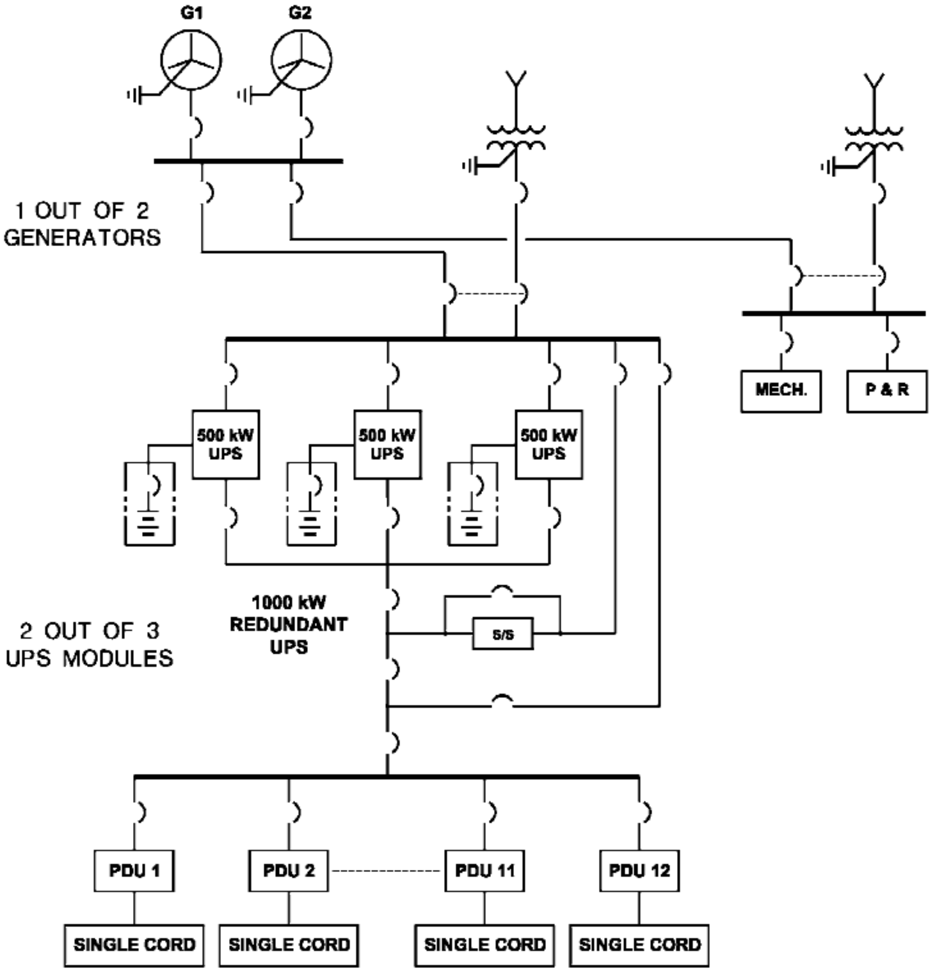

Figure 8-6—N + 1 generators and UPS modules

Shown in Figure 8-6 are two generators that connect to a generator-paralleling switchboard providing backup power to a critical distribution system. There are three UPS modules connected in a parallel redundant configuration, with a static bypass switch in a single distribution switchboard. This system would be called N + 1, since there is only one generator paralleling switchboard and one UPS system.

In a 2N system, there are two identical systems with only one required to carry the load. In the following example, the critical distribution system has two generating systems of two generators, each connecting to a separate generator-paralleling switchboard. It also has two systems of four UPS modules in a parallel redundant configuration, each with a static bypass switch. Each UPS system supplies power to separate distribution switchboards. The distribution switchboards supply power to PDUs, which consist of a step-down transformer and distribution panel. Each PDU supplies power to one side of one (or more) ASTS. The ASTS feeds a distribution panel (not shown) and single-cord loads. The ASTS is providing power to the critical load through one side of the critical distribution system (generators and UPS modules, etc.), with the other system as backup.

In the 2N system shown in Figure 8-7, it is common to have half of the ASTSs on one system and the rest on the other. This prevents a 100% step load from one UPS system onto the other, if the first system were to fail.

When the reliability of the individual component is the same, a system requiring one out of two components will be more reliable than a system requiring two out of three. Therefore a 2N system will be more reliable than N + 1 designs. However, there are also economic considerations involved, which is why reliability analysis provides a useful tool in assisting with critical facility design.

In large critical faculties, the UPS system is sometimes configured as “2(N + 1).” An example of this is shown in Figure 8-8, which has two separate UPS systems of five UPS modules operating in a parallel redundant configuration. If any four UPS modules can carry the load, then each system is N + 1, and since there are two systems, the overall UPS system is 2(N + 1). The generating system in Figure 8-8, however, is N + 1, since there is only one system and two out of three generators are required to carry the load.

The IT equipment shown in Figure 8-8 has dual-cord power supplies (two power supplies, each with their own power cord in which either power supply can provide the needed energy). One cord from each power supply is powered by a separate UPS system, to utilize the redundancy of the 2(N + 1) configuration.

Another common UPS system configuration is *distributed redundant* (DR). In this configuration, there is a redundant UPS system. Shown in Figure 8-9 is an example of a DR system requiring two out of three UPS systems to carry the critical load.

A major advantage of the DR configuration is more of the equipment capacity can be used. With a 2N configuration, only half of the capacity can be used. With a two out of three DR configuration, two-thirds of the capacity can be used.

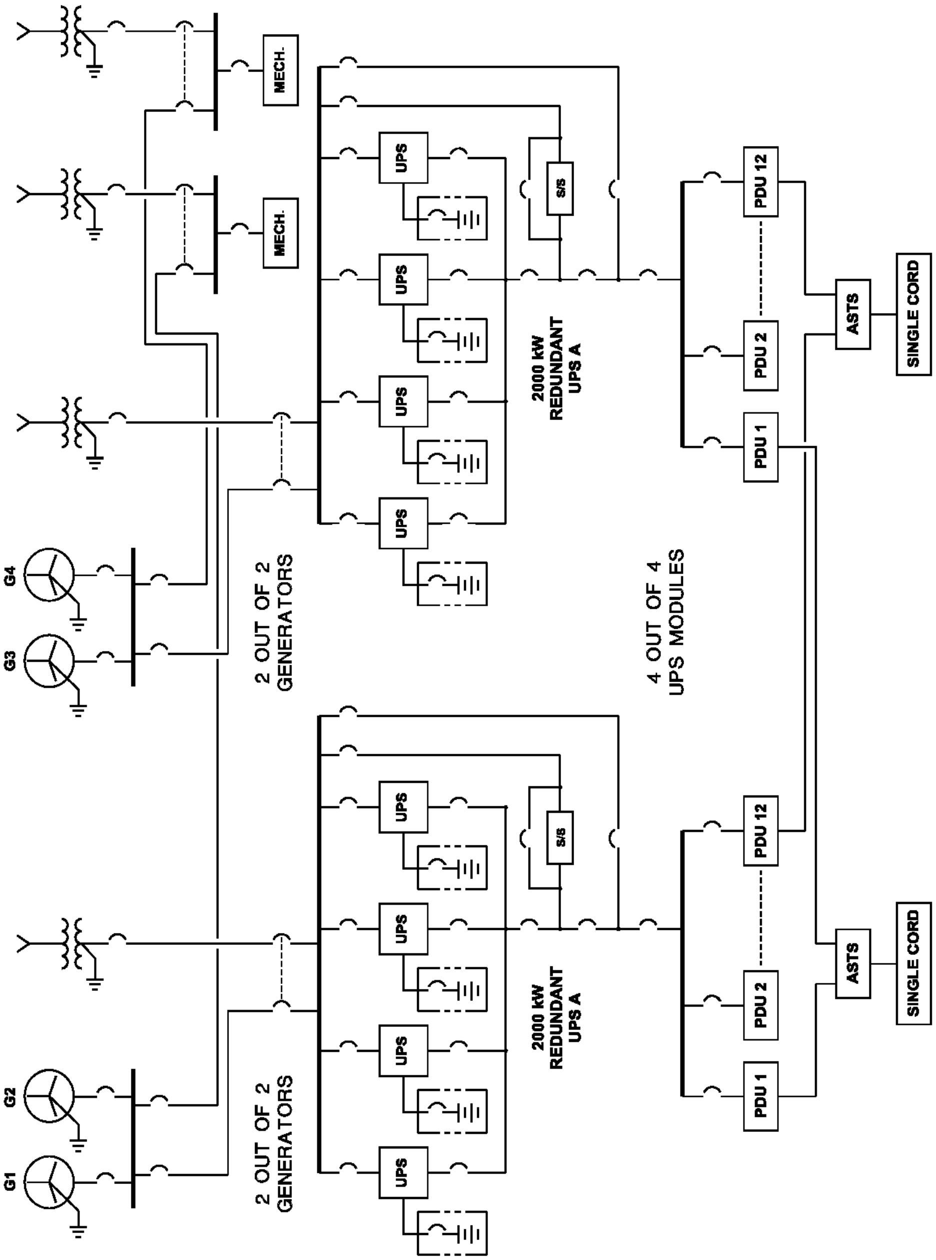

Figure 8-7—2N electrical distribution to single-cord loads

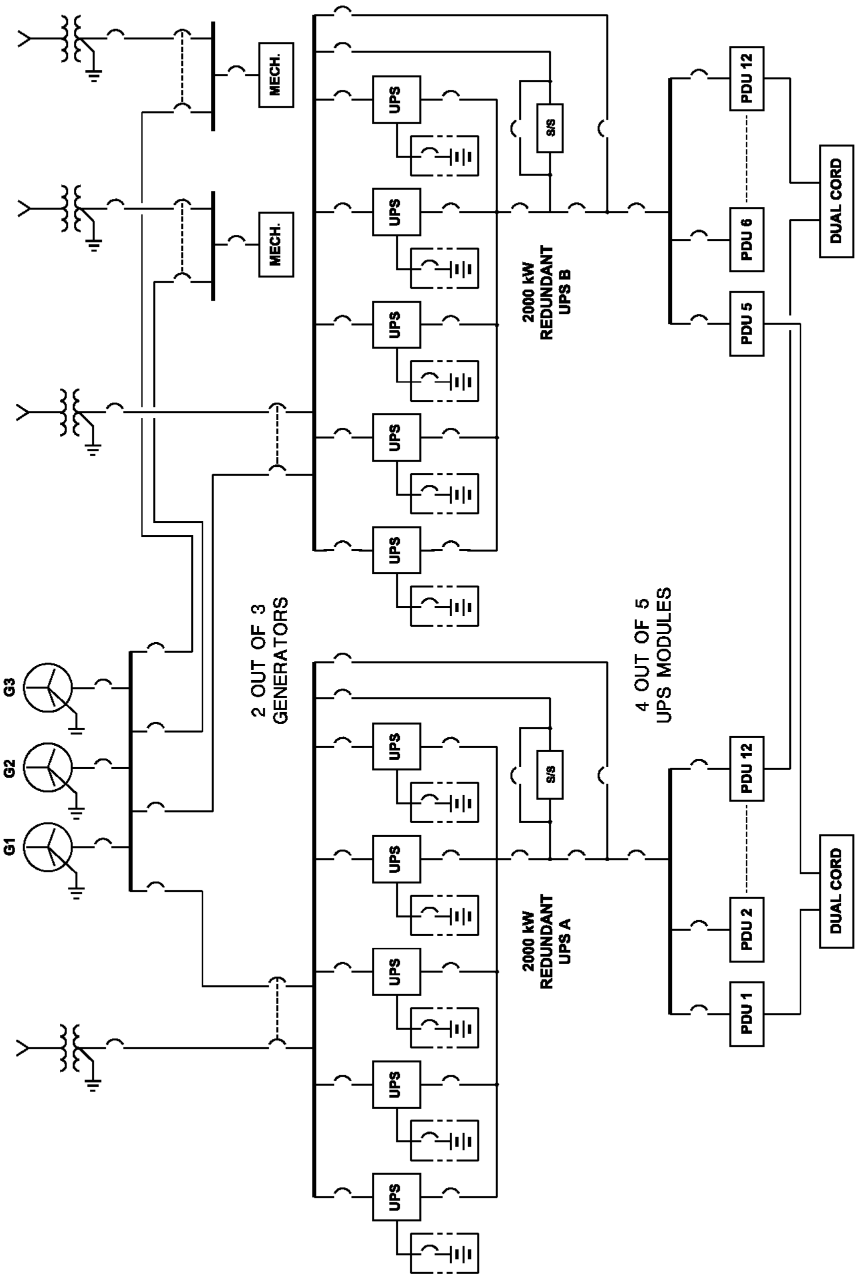

Figure 8-8—N + 1 generators, 2(N + 1) UPS system supplying dual-cord loads

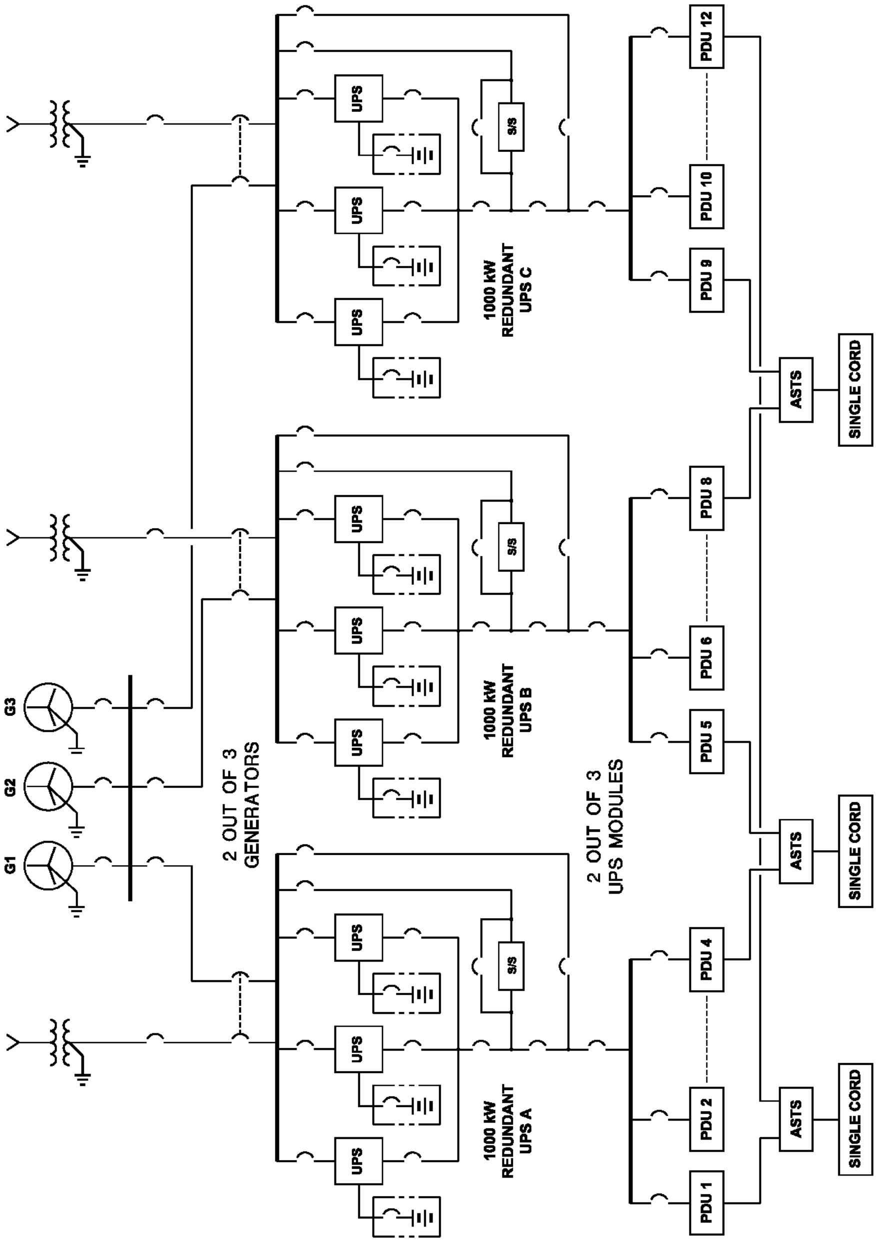

Figure 8-9—Distributed redundant UPS systems requiring two out of three systems

A disadvantage of the DR configuration, as compared to a 2N configuration, is that the system is slightly less reliable. Another disadvantage is the cable management for powering the IT equipment with dual cords from diverse sources is more complex. This will be discussed in more detail in the next subclause.

8.5.3 Single point of failure

A very successful method of improving reliability is to eliminate any SPOF. As the name implies, these are places in the electrical distribution system in which the failure of a single piece of equipment causes the system to fail. For example, in Figure 8-7 the switchboard below the UPS modules that supplies power to the PDUs is an SPOF. Should there be a fault at that switchboard, all of the critical loads would loose power.

In Figure 8-6 the switchboard supplying power to the UPS modules could also be an SPOF. Any failure that takes longer to repair than the time period the batteries can carry the load for will cause the critical loads to loose power. Therefore a fault on the switchboard itself would take down the facility. However, the main breaker tripping on a feeder fault that can be quickly located and isolated may not take down the facility.

The purpose of going to a 2N design is to eliminate SPOF. With the 2N configuration, there is a complete second system. However, to make use of the second system, there must be a method of transferring the load from one system to the other without interrupting the operation of the load.

There are two methods commonly used to accomplish this. The first method is using ASTSs to transfer the power to the PDU, distribution panels, or racks from one UPS system to the other. The second method is using IT equipment that has two power supplies built into it, either of which is capable of powering the entire load. This is commonly referred to as *dual-cord loads,* since there are two power cords (one for each power supply). With dual-cord loads, it is important to make sure that each cord is powered from a different system, or the benefit of the redundant system is lost.

8.5.4 Using ASTSs and dual-cord equipment—Load and cable management

In addition to making sure the two supplies for an ASTS or dual-cord equipment come from different sources of UPS power, it is also necessary to manage the overall load on the UPS systems. In order for redundancy to exist, there must be sufficient capacity in the UPS systems to carry the entire load they would receive if the other system failed. Therefore, in the case of a 2N configuration, the maximum load each UPS system can carry in normal operation is 50% of its system rating. For the DR configuration of Figure 8-9, each UPS system can carry 66.6% of its system rating, *provided the load is evenly balanced between all three systems*. Keeping track of how the ASTSs and dual-cord loads are distributed is often referred to as *load and cable management.*

Figure 8-9 shows the ASTSs distributed between the three systems. Each of the other PDUs in the figure would be similarly connected between the three systems. The ASTSs would have the alternate and preferred source selected to evenly distribute the load between the UPS systems. Then the IT equipment must also be evenly distributed between the PDUs.

8.6 Reliability and availability of critical distribution system configurations

8.6.1 Impact of redundancy on reliability calculations

In the previous subclause, improving reliability by eliminating SPOF and adding redundancy was discussed. Here we will provide a comparison of the critical systems discussed previously and shown in Figure 8-7, Figure 8-8, and Figure 8-9.

Table 8-1 shows the MTBF, MTTR, Ai, and the *probability of failure.* As defined in Chapter 2, probability of failure = (1 – reliability).

Table 8-1—Critical distribution systems reliability and availability

Name	Description of critical distribution system	MTBF (h)	MTTR (h)	Ai	Probability of failure (5 years) (%)
Figure 8-6: N + 1	Gen (1-2), UPS (2-3) 6 ASTS/single-cord loads	67 759.1	4.48	0.9999340	39.95
Figure 8-7: 2N	2X [Gen (1-2), UPS (2-4)] 12 ASTS/ single-cord loads	106 799.6	5.44	0.9999490	29.80
2N	2X [Gen (1-2), UPS (2-4)] 12 dual-cord loads	188 654.5	1.64	0.9999913	16.61
2(N + 1)	Gen (2-3), 2X [UPS (2-5)] 12 ASTS/ single-cord loads	111 264.2	5.63	0.9999494	28.07
Figure 8-8: 2(N + 1)	Gen (2-3), 2X [UPS (2-5)] 12 dual-cord loads	203 269.3	1.74	0.9999914	16.49
Figure 8-9: DR (2-3)	Gen (2-3), DR (2-3) X [UPS 2-3], 12 ASTS/ single-cord loads	95 476.9	4.90	0.9999487	28.84
DR (2-3)	Gen (2-3), DR (2-3) X [UPS 2-3], 12 dual-cord loads	156 564.7	1.38	0.9999912	17.05

Probability of failure is used in place of reliability to emphasize that it is a measure of the likelihood of a failure occurring during a specific time interval. MTBF, MTTR, and Ai are not functions of time, but reliability and probability of failure are time dependent. The values shown are for 5 years of operation.

A reliability block diagram (RBD) was made for of each the systems in a software program. The failure rates used for the components are from Chapter 10. The values shown in Table 8-1 are representative of the system design, not absolute calculations. The accuracy shown (e.g., to seven figures) is just a function of the software programs capability to perform statistical calculations, not the accuracy of the results.

It should also be noted that the probability of failure values given in Table 8-1 are for one single-cord or dual-cord load out of the group of 12 failing. As discussed in 8.2, the system is modeled in this manner to be an indication of the probability of losing all the loads on a PDU, not all the loads in the data center.

For the N + 1 system shown in Figure 8-6, Ai is 0.999934. Essentially that would mean that the system is likely to experience one outage in a little less than 8 years that will last for about 4.5 h. As discussed in 8.3.1, this would be far better than an outage every year that lasts for about 33 min. Yet both would have the same Ai.

That the reliability is significantly improved by eliminating SPOF can easily be seen by comparing the previous three configurations, 2N, 2(N + 1) and the 2 out of 3 DR with ASTSs and single-cord loads to the same three system with dual-cord loads. In each of the three cases, the difference between the systems with ASTS/single-cord loads to the systems with dual-cord loads is just one SPOF—the ASTS. Yet in each case, the probability of failure is reduced by a factor approaching 2 (an average of about 1.7).

The system with the most UPS redundancy, 2(N + 1), is the most reliable. At first glance this might be somewhat confusing, since the 2(N + 1) system has only N + 1 generators, while the 2N system has 2N generators and UPS systems. However, the UPS systems are always in service, but the generators are only in service when the utility fails. For the previous examples, the MTBF of the utility is 4478 h and the MTTR is 1.32 h. Therefore, the generators on the average are needed twice a year for about an hour and a half each time. Since there is generator redundancy in both systems, it is highly likely that the generators will be available when needed.

8.6.2 Impact of facility size on reliability calculations

As mentioned in the earlier subclauses, the larger the facility, the lower the reliability will be just because there are more parts to fail. Table 8-2 shows an example of this using the 2N system of Figure 8-8.

Table 8-2—Impact of facility size on reliability and availability

Name	Description of critical distribution system	MTBF (h)	MTTR (h)	Inherent avail-ability	Probability of failure (5 years) (%)
2N – 12 loads	2N [Gen (1-2), UPS (2-4)] 12 dual-cord loads	188 654.5	1.64	0.9999913	16.61
2N – 24 loads	2N [Gen (1-2), UPS (2-4)] 24 dual-cord loads	100 347.4	1.75	0.9999825	31.13
2X 2N – 2X (12 loads)	2X 2N [Gen (1-2), UPS (2-4)] 2X (12 dual-cord loads)	96 455.2	1.67	0.9999827	30.61

The first set of calculations is the 2N system with dual-cord loads used previously: two systems of one out of two generators and two out of four UPS modules supplying power to 12 dual-cord loads. The second set of calculations is for the same 2N system with 24 dual-cord loads. The third set of calculations is for two complete 2N systems (double the first example of a 2N system). There are two systems of one out of two generators (eight total generators) and a total of four sets of two out of four UPS modules supplying power. Each of the two UPS systems (paired together as 2N) supply 12 dual-cord loads, for a total of 24 dual-cord loads.

In comparing the first set to the second, the numbers are dropped dramatically by doubling the number of critical loads connected to the UPS modules. The third set shows that essentially doubling the size of the 2N facility also drops the reliability significantly. This example shows that it is very important to keep the models consistent when comparing one configuration to the next.

8.6.3 Operational availability vs. inherent availability

As discussed in Chapter 2, there are two common measures of availability: *inherent availability* (Ai) and *operational availability* (Ao). The difference between the two is based on what is included as *repair time.* For Ai, only the time it takes to fix the equipment is included. Ai assumes that the technician is immediately available to work on the equipment the moment it fails, and that he has all the parts, etc. necessary to complete the repair. For Ao, all the delays for scheduling, travel time, parts, etc., are included. If it takes 24 h to fly a part in to repair the equipment, that adds to the repair time.

Ai and Ao show different aspects of the system being analyzed. Ao would be the "real world"—how the system really operates. There are usually delays between the time a piece of equipment fails and when the repair begins. Spare parts inventories are also very significant and directly impact Ao. Therefore, when determining spare parts inventories, on-site personnel and their level of training, etc., Ao is a useful tool.

In some commercial 7 × 24 facilities, it is common for maintenance to be done by outside contractors working under service level agreements. It is possible to use reliability modeling to produce a cost/benefit analysis of service level agreements and spares parts stocked. A certain quantity of critical spares held on site at a particular cost would improve the total time for repair, which in turn would improve the Ao.

Ai is a more useful tool in analyzing the system design. Since there are wide variations in the maintenance practices from facility to facility, Ao could vary significantly between two facilities with identical infrastructures. Eliminating all of the logistics involved with getting the parts and trained individual to the piece of equipment, and counting only the actual repair time, provides a more accurate comparison. It shows the availability that is "inherent" to the design, if the spare parts inventory and repair are perfect.

8.7 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 142™, IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems (*IEEE Green Book*™).[3, 4]

IEEE Std 1100™, IEEE Recommended Practice for Powering and Grounding Electronic Equipment (*IEEE Emerald Book*™).

NFPA 70, National Electrical Code® (NEC®).[5]

8.8 Bibliography

[B1] Gross, P., "Configuration of Large UPS Systems for Super-Critical Applications," Power Quality Conference Proceedings, Irvine, 1993.

[B2] Gruzs, Thomas M., "Redundancy Options for Critical Uninterruptible AC Power Systems: Which Type of Redundancy is Best?" *International Power Quality 1998 Conference.*

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[3] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

[4] The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

[5] The NEC is published by the National Fire Protection Association, Batterymarch Park, Quincy, MA 02269, USA (http://www.nfpa.org/). Copies are also available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

[B3] Hale, Peyton S., and Arno, Robert G., “Survey of Reliability and Availability Information for Power Distribution, Power Generation, and HVAC Components of Commercial, Industrial, and Utility Installations,” *IEEE I&CPS 2000 Conference,* May 7–11, 2005. (See Annex Q.)

[B4] IEEE 100, *The Authoritative Dictionary of IEEE Standards Terms,* Seventh Edition. New York: Institute of Electrical and Electronics Engineers, Inc.

Chapter 9
Reliability and maintainability verification

9.1 Introduction

The design and operation of power equipment and systems may or may not be in compliance with specifications dictated by both the manufacturers and their customers. One of the difficulties in practice is to define a "testing plan" to demonstrate whether the performance of new or existing power equipment and systems comply with these dual specifications or not. This chapter presents the basic equations of a generalized statistical model for an equipment reliability testing plan and compares it with the specific International Electrotechnical Commission's standard publication IEC 61123.[1] Detailed references, discussions, definition of terms, illustrations, and a case study will be presented to provide an understanding of the complex area of demonstrating the reliability of new or existing power equipment and systems. The ability of equipment and systems to operate as reliably and economically as possible and be compliant with multiple specifications is a prime goal of society (see IEEE Std 446™, *IEEE Orange Book*™).

From a manufacturer's viewpoint, it is important to test power equipment and systems to determine whether they meet or exceed desired or required performance specifications. In testing a system for adequacy, the manufacturer can interpret a negative test result in several ways. For example, a single negative test result implies the system being tested does not conform to the manufacturer's specifications and is therefore unreliable. However, it is important to note that a single negative test result may or may not statistically demonstrate that a system's performance is unreliable. A testing plan involving more than one test and a statistical criterion for adequacy is usually required to resolve the dilemma of demonstrating system adequacy. A negative test result may occur by chance when the actual system's reliability is equal to or greater than its specifications. In these situations, the manufacturer runs a risk of rejecting a system that is acceptable according to specifications, a costly venture for the manufacturer.

From a customer's viewpoint, the acquisition of power equipment or a system has been justified, for example, from a reliability-cost/reliability-worth (IEEE Std 493™-1997) analysis in which the cost of interruptions exceeds the cost of not having this equipment or system. In many cases equipment and systems are a mandatory requirement dictated by various regulators (see IEEE Std 446, *IEEE Orange Book*). However, the acceptance of equipment or a system that does not conform to a customer's specifications (e.g., an unacceptable system reliability level) can quickly erase the economic benefits of having this system.

From both perspectives, power equipment or systems that meet or exceed the specifications of both parties are desirable. To achieve this objective, a testing plan must be developed that clearly defines the number of tests that are required to demonstrate whether a system conforms or does not conform to various manufacturer and customer

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[1] Information on references can be found in 9.12.

specifications. The testing plan must define the number of tests to be performed and the number of allowable equipment of system failures for compliance and noncompliance based on the manufacturer's and customer's specifications. The defined limits of acceptance or rejection of a system's performance must minimize the risks to the manufacturer and their customers (e.g., rejecting equipment that complies with the manufacturer's specifications and accepting equipment that does not comply with the customer's specifications). An emergency and standby system, for example, may be considered to be inadequate if it fails to respond immediately after the detection of a power supply interruption or if it fails to maintain continuity of service to the load for some specified period.

The frequency of system failures is dependent upon many factors, for example:

a) Use of new or old technology in the design of the system
b) If the system is a combination of old and new components
c) Stress placed on the system during operation (e.g., beyond the design limits)
d) Frequency of maintenance
e) Frequency of "utilizing" a system and the manner in which it is performed
f) Equipment characteristics and environmental factors, etc.

The overall performance of power equipment and systems can often be characterized by a single variable, its failure rate. The failure rate of electrical equipment can exhibit various characteristics (see IEEE Std 493-1997 and Jensen and Petersen [B1]).[2] It is often assumed that the equipment's failure rate tends to follow the "bathtub curve" (Jensen and Petersen [B1]) in which the equipment's early life is characterized by a high failure rate that decreases with time until it stabilizes at an approximate constant value for a long period of time. As the electrical equipment reaches the end of its designed life, its failure rate begins to significantly increase with time. In the testing model developed in this chapter, it will be assumed that the failure rate of electrical equipment is constant value (i.e., an average value) or is represented by the percentage of the time the system fails to comply with its specifications under test and/or operation.

9.2 Definition of success ratio

One of the key variables defined by IEC in their sampling plans is called a *success ratio*. A success ratio is defined (IEC 60605-5) as the probability that a system will perform a required function (e.g., an emergency and standby system starting and operating for a fixed period of time) or a test will be successful under stated conditions (i.e., conforming to specifications). An observed success ratio is the ratio of the number of successful tests at the completion of testing compared to the total number of tests performed on the equipment or system.

In this chapter the terms *equipment* and *systems* will be interchanged. The proposed testing plan can be applied to individual power equipment (e.g., components) or systems

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[2] The numbers in brackets correspond to those of the bibliography in 9.13.

composed of power and/or electronic equipment provided their operational performance is characterized by two success ratios specified by the manufacturers and their customers.

9.3 Acceptance sampling plan

The probability of obtaining different combinations of successful and failed test results after n tests will be initially characterized by the binomial distribution given by Equation (9.1):

$$P(n,r) = nCr(R)^{n-r}\,(Q)^{r} \tag{9.1}$$

where

r is the cumulative number of failed tests after n tests

n is the number of tests performed

R is the equipment or system success ratio

Q is the equipment or system failure ratio equal to $1 - R$

nCr is the binomial coefficient

The definitions and symbols used in this chapter are based on IEC definitions. The reader is cautioned that these definitions do not necessarily match the definitions in other chapters.

A common viewpoint on demonstrating reliability performance of equipment is to subject the equipment or system to a series of tests. If the equipment passes all the tests, it is concluded the equipment is acceptable and complies with the specifications. If the equipment fails any of the tests, it is unacceptable. This belief may be problematic depending upon the number of tests performed and the success ratios defined by the manufacturers and their customers.

System operating characteristic curves show the probability of accepting the performance of equipment under test as adequate (i.e., compliance to specifications) as a function of success ratios. Each curve represents a fixed number of tests. The acceptance criterion is defined by a fixed number of observable failures. If after n tests, the number of observable test failures is less than or equal to the fixed number, then the performance of the system or equipment is assumed to be acceptable and complies with its specifications. A typical operating characteristic curve for an acceptance criteria of observing no failures after n trials is shown in Figure 9-1.

The probability of accepting equipment performance as adequate after observing “no” failures after n tests is given by Equation (9.2):

$$P(n,0) = Rn = Pa \tag{9.2}$$

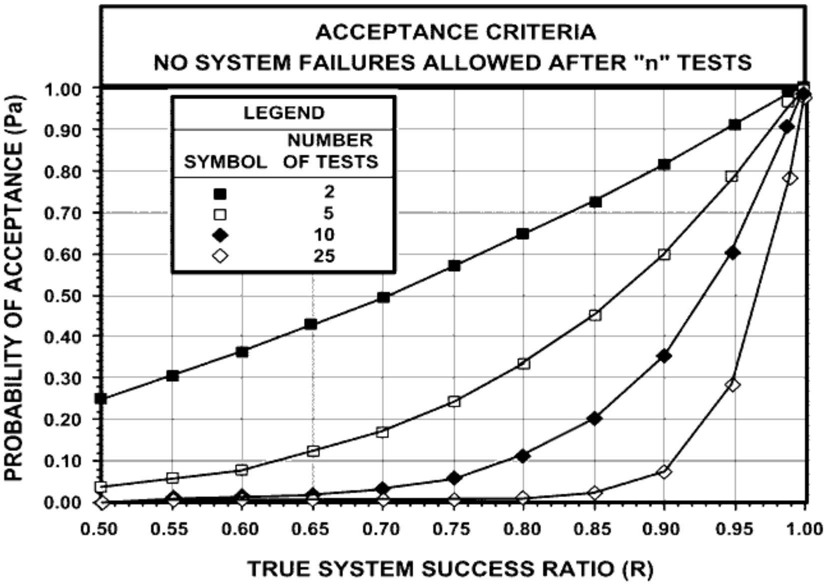

Figure 9-1—System operating characteristic curves for no test failures

For a fixed success ratio (*R*), the probability of accepting the performance exhibited by a system as adequate decreases significantly as the number of tests increases. If the number of tests conducted is low, there is a high probability of accepting the test results concluding the system is adequate even if its success ratio is low.

9.4 Minimizing manufacturer and customer risks

The determination of the adequacy of an emergency and standby power system based on a fixed number of tests and an acceptance criteria may or may not minimize the risks to both the manufacturer and their customers. For a given number of tests an acceptance criteria specifies the number of successful test results that must be observed to demonstrate that a given system's performance complies with certain specifications. In this sublcause, the risks are not included in the acceptance criteria as previously defined.

A system operating curve for 25 tests and an acceptance criteria of allowing no failures to be observed during the testing plan is shown in Figure 9-2. The manufacturer usually specifies a success ratio (*R*o) for their system that is often incorporated in their system specifications. The objective of the testing plan is to demonstrate that a system's success ratio is at least the value *R*o. During the testing plan, the manufacturer runs a risk of the *test revealing that the system is inadequate* when in reality the system's true success ratio is at least equal to the manufacturer's acceptable level of *R*o (e.g., *R*o = 0.99 in Figure 9-2). The probability of this event happening is defined as α (e.g., 0.22).

The major risk to the customer from the results of a testing plan is the acceptance of a system as adequate when the true system success ratio is equal to the customer's unacceptable value of $R1$ (e.g., $R1 = 0.97$, Figure 9-2). The probability of this event occurring ($Pa1$), i.e., the risk to the customer is β (e.g., $\beta = 0.47$, Figure 9-2). If the customer's risk is too high for a given success ratio $R1$, then the number of tests must be increased to reduce the value of β as can be seen from Figure 9-1. The fundamental question that must be answered is: "How many tests are required to minimize the unique risk levels defined by the manufacturer and their customers?"

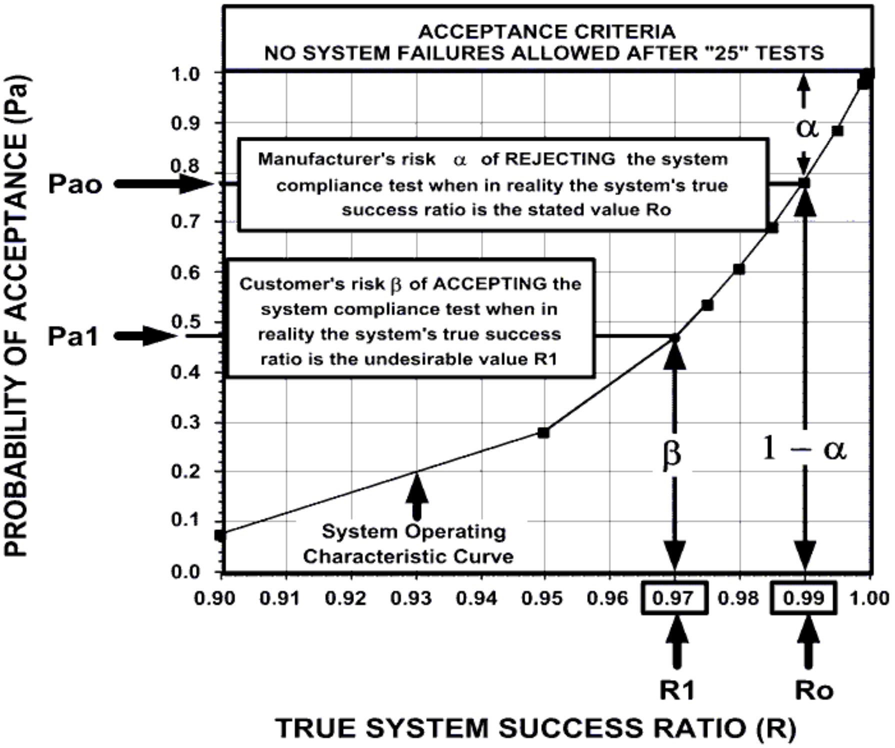

Figure 9-2—System operating characteristic curve indicating manufacturer and customer's risks

9.5 Sequential testing plan

A sequential testing plan is analogous to a continuous game of testing a system and observing whether the test results are positive or negative (i.e., pass or fail the test). If the test results are positive, we score "0" points. If the test results are negative, we score "1" point. We continue testing the system and summing the scores after each test.

If the cumulative score is below a certain defined value after x tests, then we stop the testing procedure and conclude the system meets our specifications. If the cumulative score at any time during the test exceeds a certain defined value r after n tests, then we stop the testing procedure and conclude the system does not meet our specifications.

The difficulty with the testing plan is we have to define the limits of the game (i.e., r, the number of failed tests; x and n, the number of tests to be performed). In addition to these unknowns, the game can be further restricted by minimizing the risk to the manufacturer (i.e., α) of rejecting systems that comply with the manufacturer's specifications and minimizing the risk to the customers (i.e., β) of accepting systems that do not comply with the customer's specifications. These specifications define what is considered "adequate" for the manufacturer and "not adequate" for the customer.

9.6 Development of a sequential testing plan

Wald [B2] provides a testing procedure for determining the boundaries in a compliance test for accepting and rejecting a system's performance as a function of the number of tests n and the number of failed tests r permitted, given the following test parameters:

a) Acceptable value of success ratio Ro specified by the manufacturer
b) Unacceptable value of success ratio $R1$ specified by the customer
c) Manufacturer's risk α (i.e., the probability of the compliance test rejecting a system whose true success ratio is equal to the desired level Ro)
d) Customer's risk β, (i.e., the probability of the compliance test accepting a system's performance whose success ratio is equal to the undesirable level $R1$)

The probability of obtaining a sample equal to the observed set of test results $\{x1, x2, x3, ..., x_n\}$ where x_i is the result of the ith test, i.e., either a "0" for a successful trial or a "1" for an unsuccessful trial is given by Equation (9.3):

$$K\,R^{n-r}\,(Q\text{o})^{r} \tag{9.3}$$

where

n is the number of tests performed
r is the number of unsuccessful tests in n tests
R is the success ratio of the observed set of test results $[R = (n-r)/n]$
Q $(Q = 1 - R)$
K is the number of possible ways of achieving a success ratio of R at the end of n tests and is not the binomial coefficient

If the actual system success ratio $R = R$o, the manufacturer's desired level, then the probability of obtaining a sample meeting this constraint is given by Equation (9.4):

$$K\,R\text{o}^{n-r}\,(Q\text{o})^{r} \tag{9.4}$$

Conversely, if the true system success ratio $R = R1$, the customer's undesired level, then the probability of obtaining a sample with a success ratio equal to $R1$ is given by Equation (9.5):

$$K\,R1^{n-r}\,(Q1)^{r} \tag{9.5}$$

Once the test parameters Ro, $R1$, α, β have been defined, the number of unknown variables (n, the number of tests and r, the number of failures) can be determined from the *sequential probability ratio* (SPR) (see Wald [B2]) of Equation (9.3) and Equation (9.4):

$$\text{SPR} = [[K\,Ro^{n-r}\,(Qo)^{r}] / [K\,R1^{n-r}\,(Q1)^{r}]] \tag{9.6}$$

9.7 Compliance sequential test acceptance limits

The numerator of SPR shown in Equation (9.6) can be interpreted to be the probability of a set of test results (whose success ratio equals Ro) being accepted and should be greater than or equal to $(1 - \alpha)$ to comply with the manufacturer's risk specification. The denominator of SPR can be interpreted to be the probability of a set of test results (whose success ratio equals $R1$) being accepted and should be greater than or equal to β to comply with the customer's risk specification.

Equation (9.6) can be rewritten to include the acceptance risks to both the customer and manufacturer, as shown in Equation (9.7):

$$[(1-\alpha)/\beta] = [[K\,Ro^{n-r}\,(Qo^{r}] / [K\,R1^{n-r}\,(Q1)^{r}]] \tag{9.7}$$

Every set of values (n, r) that satisfies Equation (9.7) represents an acceptance coordinate in an n vs. r Cartesian coordinate system. The solution of the variables n and r can be evaluated from Equation (9.7). The number of defects r for the compliance test as a function of the number of tests n is given by Equation (9.8):

$$r \le \frac{\log[(1-\alpha)/\beta] - (n)\log((Ro)/R1)}{\log(QoR1/Q1Ro)} \tag{9.8}$$

Equation (9.8) can be rearranged to conform to IEC 60605-5 as shown in Equation (9.9) and Equation (9.10):

$$r = \frac{(n)\log(Ro/R1) - \log[(1-\alpha)/\beta]}{\log(Q1Ro/QoR1)} \tag{9.9}$$

$$r \le sn - ho \tag{9.10}$$

where

$$s = \frac{\log(Ro/R1)}{\log(Q1Ro/QoR1)}$$

$$ho = \frac{\log[(1-\alpha)/\beta]}{\log(Q1Ro/QoR1)}$$

With reference to Equation (9.9), if r is equal to or less than the calculated value, the values of r will satisfy the constraints on the testing plan imposed by Equation (9.7). The value of r in n tests is acceptable, indicating that the system complies with the specifications imposed on it.

Equation (9.10) is a linear equation whose abscissa is n (the number of tests to be performed) and r (the number of acceptable test failures for acceptance) as the ordinate. This is graphically illustrated in Figure 9-3.

An examination of Figure 9-3 reveals, for example, that a minimum of 107 tests in which no failures occurred are required to state that the system complies with its specifications dictated by the customer and manufacturer (i.e., for a fixed α, β, Ro, R1).

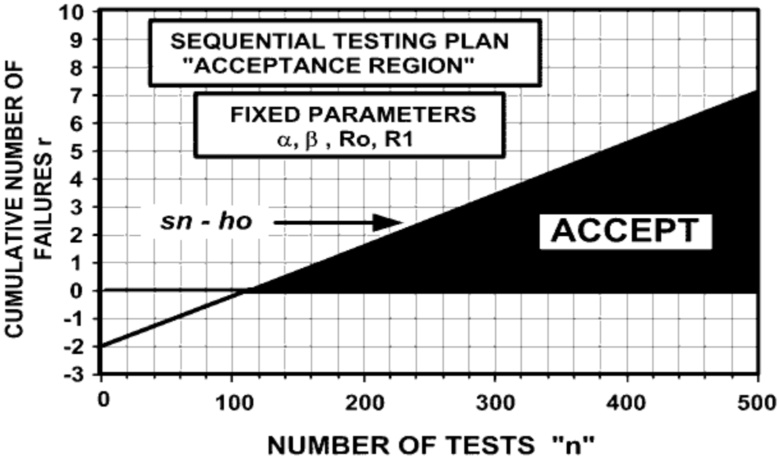

Figure 9-3—Number of tests vs. number of failures required to demonstrate compliance to system specifications

9.8 Compliance sequential test rejection limits

The numerator of SPR shown in Equation (9.6) can be interpreted to be the probability of a set of test results (whose success ratio equals Ro) being rejected. The probability should be less than or equal to α to comply with the manufacturer's risk specification. The denominator of SPR can be interpreted to be the probability of a set of test results (whose success ratio equals R1) being rejected. The probability should be less than or equal to (1– β) to comply with the customer's risk specifications.

Equation (9.6) can be rewritten to include the rejection risks to both the customer and manufacturer as shown in Equation (9.11):

$$[\alpha/(1-\beta)] = [[K\,Ro^{n-r}\,(Qo)^{r}] / [K\,R1^{n-r}\,(Q1)^{r}]] \tag{9.11}$$

Every set of values (*n, r*) that satisfies Equation (9.11) represents a rejection coordinate in an *n* vs. *r* Cartesian coordinate system. The solution of the variables *n* and *r* can be evaluated from Equation (9.11). The number of unacceptable defects *r* for compliance test as a function of the number of tests *n* is given Equation (9.12):

$$r = \frac{\log[\alpha/(1-\beta)]-(n)\log((Ro)/R1)}{\log(QoR1/Q1Ro)} \tag{9.12}$$

Equation (9.12) can be rearranged to conform to IEC 60605-5 as shown in Equation (9.13) and Equation (9.14):

$$r \geq \frac{(n)\log(Ro/R1)-\log[(1-\beta)/\alpha]}{\log(Q1Ro/QoR1)} \tag{9.13}$$

$$r \geq sn + h1 \tag{9.14}$$

where

$$s = \frac{\log(Ro/R1)}{\log(Q1Ro/QoR1)}$$

$$h1 = \frac{\log[(1-\beta)/\alpha]}{\log(Q1Ro/QoR1)}$$

With reference to Equation (9.13), if *r* is equal to or less than the calculated value, the values of *r* will satisfy the constraints on the testing plan imposed by Equation (9.11) resulting in the conclusion that the system is unacceptable and does not comply with its specifications.

Equation (9.14) is a linear equation in terms of *n* and *r* where *r* is the number of test failures required to demonstrate that the system under test is unacceptable. The region of rejection lies above the line described by Equation (9.14) and is illustrated in Figure 9-4.

An examination of Figure 9-4 reveals, for example, that if after approximately 75 tests more than 3 failures are observed, then the system does not comply with its specifications. If the 3 failures occur before the 75th test, then the testing plan is halted and the system is assumed to be unacceptable and does not comply with its specifications.

The acceptance and rejection lines shown in Figure 9-3 and Figure 9-4, respectively, can be merged into a single graph as shown in Figure 9-5. The area between the acceptance and rejection lines is a statistical transition area where it is necessary to “continue testing” until a clear decision can be reached.

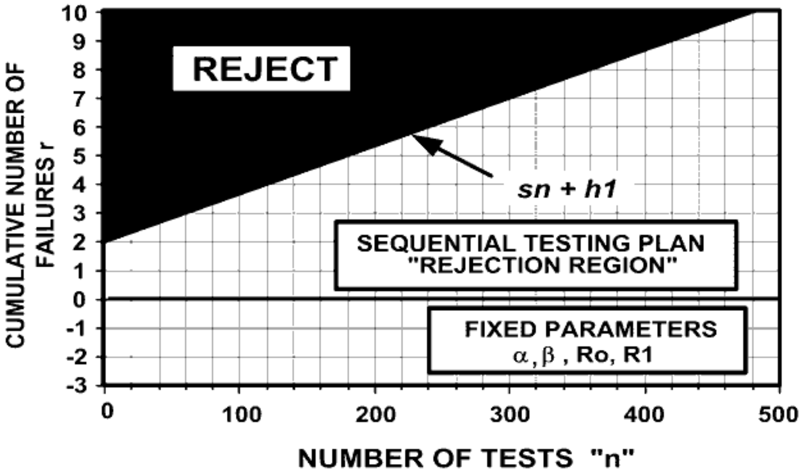

Figure 9-4— Number of tests vs. number of failures required to demonstrate noncompliance to system specifications

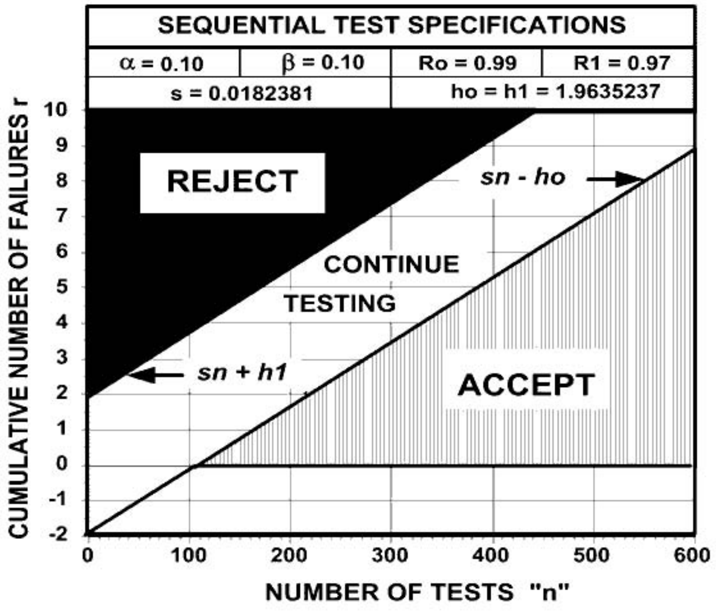

Figure 9-5—Number of tests vs. number of failures with sequential test boundaries

9.9 Case study

A manufacturer of emergency and standby systems and one of their key customers have agreed to share their field data for this case study. Both parties insisted on being anonymous. The manufacturer stated to the customer that their emergency and standby power system was designed for an average success ratio $R\text{o} = 0.99$ based on field records. Based on the customer's reliability cost-reliability worth studies, it was concluded that the emergency and standby power system would be uneconomical and unacceptable if the system's success ratio was less than 0.97 (i.e., $R1$).

Further economical studies and discussion between the manufacturer and the customer resulted in an agreement to share the risks of the compliance test. The risk level was set at 10% (i.e., $\alpha = \beta = 0.10$). An examination of Figure 9-5 reveals a total of 108 tests in which no system failures occurred are required to demonstrate that the emergency and standby power system complies with the sequential test specifications.

The customer specified that the manufacturer had to demonstrate the success ratio of their emergency and standby system for 3 years (i.e., based on the sequential test specifications agreed to by the manufacturer and the customer) after the installation of the system. The nature of the installation required it to be tested weekly and detailed records of successful tests and failures were maintained as shown in Table 9-1.

Table 9-1—Sequential compliance test results

Test number	Test results	Comments
1 to 15	Successful	
16	1st failure	Failed to pickup load
17 to 25	Successful	
26	2nd failure	DC power supply failure
27 to 46	Successful	
47	3rd failure	Failure to pick up load
Testing halted	System fails compliance test	
Manufacturer and customer detect a major installation error and correct it.		
Testing procedure initiated		
1 to 103	Successful	
104	1st failure	Hardware failure
104 to 163	Successful	
Modified system complies with test specifications and is acceptable.		

An examination of Table 9-1 reveals a total of three system failures were observed by the 47th test. When the (47, 3) coordinate is plotted on Figure 9-5, the point lies in the rejection zone, i.e., the system *does not* meet specifications.

A thorough investigation of the emergency and standby power system by the manufacturer and the customer revealed a major installation error that was subsequently corrected. The sequential testing plan was then initiated. After 163 tests, only one failure was observed. When the (163, 1) coordinate is plotted on the (n, r) Cartesian coordinate system shown in Figure 9-5, the point lies in the acceptance zone, i.e., the emergency and standby power system is acceptable and complies with the manufacturer-customer sequential test specifications.

9.10 Discussion of sequential tests

Initially, many viewers of Figure 9-5 will conclude that many tests are required to statistically demonstrate that a system's performance complies with its specifications. For this case study, their conclusion would be correct. However, it is important for the reader to understand that the number of tests required to demonstrate that a system does or does not comply with specifications is entirely dependent upon the "sequential test specifications" agreed to by the manufacturer and their customers.

To illustrate the significance of these test specifications, the manufacturers and customer's risk levels will be fixed at two distinct levels, the manufacturer's acceptable success ratio (Ro) will be fixed at 0.99 and the customer's undesirable success ratio (R1) will be allowed to vary. Under these constraints, the number of successful tests in a row that are required to demonstrate system compliance is calculated using Equation (9.10) and the results are shown in Table 9-2.

A term used in IEC 60605-5 to differentiate between the manufacturer's desired success ratio (Ro) and the customer's undesirable success ratio R1 is called a *discrimination ratio* (DR), which is defined as shown in Equation (9.15):

$$\mathrm{DR} = \frac{Q1}{Q\mathrm{o}} = \frac{1.0 - R1}{1.0 - R\mathrm{o}} \tag{9.15}$$

It is clear from the results shown in Table 9-2 that as the discrimination ratio increases, the number of tests required to demonstrate a system's compliance to the sequential test specifications significantly decreases for fixed manufacturer-customer risk level.

Table 9-2—Number of tests in which no observed failures occurred that are required to demonstrate system compliance

Manufacturer's desired success ratio *R*o = 0.99			
Customer success ratio (*R*1)	**Discrimination ratio (DR)**	**Number of sequential tests (compliance with no failures)**	
		$\alpha = \beta = 0.10$	**$\alpha = \beta = 0.05$**
0.98	2	217	290
0.97	3	108	145
0.95	5	54	72
0.90	10	24	31
0.85	15	15	20
0.80	20	11	14

9.11 Conclusion

This chapter has presented the development of a generalized sequential test plan for demonstrating whether a power system and/or it parts comply with the specifications dictated by the customer and manufacturer. The number of observed system failures vs. the number of tests required for compliance evaluation is shown graphically.

Acceptance and rejection lines are placed on the Cartesian coordinate system to define three distinct zones: reject, continue testing, and acceptance. These regions are defined completely by four parameters (i.e., *R*o, *R*1, α, and β) necessary to define the sequential test parameters.

When the difference between the customer's undesirable system success ratio (*R*1) and the manufacturer's desired system success ratio (*R*o) is small, a large number of tests are required to statistically demonstrate that a system complies with these specifications. The large number of tests can be obtained by examining an existing emergency and standby system's testing data to validate its performance in conjunction with its specifications. For new systems, the testing procedure can be either done at the factory or after it has been installed, however, no conclusion as to the new system's adequacy can be stated until a significant number of successful test results have been obtained (see Table 9-2).

The acceptance and rejection line equations are expressed in a general form that allows the risks to the manufacturer and the customer to be unique (i.e., α not equal to β) as opposed to IEC 60605-5, which accommodates only equal risk cases and references unequal risks cases.

9.12 Normative references

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEC 60605-5, Equipment reliability testing—Part 5: Compliance test plans for success ratio.[3] (Superseded by IEC 61123.)

IEC 61123, Reliability testing—Compliance test plans for success ratio. (Supersedes IEC 60605-5.)

IEEE Std 446, IEEE Recommended Practice for Emergency and Standby Power Systems for Industrial and Commercial Applications *(IEEE Orange Book)*.[4, 5]

IEEE Std 493-1997, IEEE Recommended Practice for the Design of Reliable Industrial and Commercial Power Systems *(IEEE Gold Book™)*.

9.13 Bibliography

[B1] Jensen, Finn, and Petersen, Niels Erik, *Burn-in: An Engineering Approach to the Design and Analysis of Burn-in Procedures*. New York: John Wiley & Sons, 1982.

[B2] Wald, Abraham, *Sequential Analysis*. New York: John Wiley & Sons, 1947.

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[3] IEC publications are available from the Sales Department of the International Electrotechnical Commission, Case Postale 131, 3, rue de Varembé, CH-1211, Genève 20, Switzerland/Suisse (http://www.iec.ch/). IEC publications are also available in the United States from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13th Floor, New York, NY 10036, USA.

[4] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

[5] The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc.

Chapter 10
Summary of equipment reliability data

10.1 Introduction

A knowledge of the reliability of electrical equipment is an important consideration in the design and operation of industrial and commercial power distribution systems. The failure characteristics of individual pieces of electrical equipment (i.e., components) can be partially described by the following basic reliability statistics:

a) Failure rate, often expressed as failures per year per component (failures per unit-year);

b) Downtime to repair or replace a component after it has failed in service, expressed in hours (or minutes) per failure; and

c) In some special cases, probability of starting (or operating) is used.

Reliability data on the pertinent factors (e.g., cause and type of failures, maintenance procedures, repair method, etc.) is also required to practically characterize the performance of electrical equipment in service (refer to Annex A and Annex B).

The reliability performance of industrial and commercial electrical power distribution systems (e.g., economic operation, frequency and duration of equipment and system outages, etc.) can be estimated from a knowledge of the reliability data of individual electrical parts (i.e., components) that are interconnected to form an operating system. The analytical models required for estimating the reliability of various power system configurations are presented in Chapter 2 and Chapter 9.

For a system such as an electrical power facility, availability is a key measure of performance. An electrical power facility must operate for very long periods of time, providing power to other systems that perform critical functions. Even with the best technology and most robust design, it is economically impractical, if not technically impossible, to design power facilities that never fail over weeks or months of operation. Although forced outages (FAs) are never welcome and power facilities are designed to minimize the number of FAs, they still occur. When this happens, restoring the system to operation as quickly and economically as possible is paramount. The maintainability characteristics of the system limit how quickly and economically system operation can be restored.

This chapter summarizes the reliability data collected from equipment reliability surveys and a data collection program over a period of 35 years or more. The chapter is divided into three parts, consisting of an equipment data collection conducted between 1990 and 1993 (Part 1, see 10.2), equipment surveys conducted between 1976 and 1989 (Part 2, see 10.3), and equipment surveys conducted prior to 1976 (Part 3, see 10.4). Detailed reports on the surveys and data collection efforts are given in the annexes and references. Detailed lists of references on equipment reliability are presented in the annexes. Selected reliability and availability numerics from the data collection and survey efforts are presented in this chapter. The Part 1 information represents an extensive data collection program on several different commercial facilities within the U.S. The information in Parts 2 and 3 represents equipment survey data collected from responses to questionnaires. The results of these surveys in Parts 2 and 3 are discussed and compared. The two distinct sources of data are presented separately and not merged for several reasons. Details of survey data (Parts 2 and 3) are not available to statistically merge with the data collected in Part 1. Part 1 represents the "new generation" of equipment that should not be merged with the older types of equipment. Also, Part 1 provides the analyst with greater options, both mechanical and electrical equipment, when analyzing a facility with various equipment types and ages.

Part 1 describes the culmination of a 24 000 man-hour effort to collect operational and maintenance data on 239 power generation, power distribution, and HVAC items, including gas turbine generators, diesel engine generators, switchgear assemblies, cables, boilers, piping, valves, and chillers. It is presented to identify the effects of "newer technology" equipment, i.e., equipment installed after 1971, on availability. The central hypothesis was that this new equipment would exhibit a significant increase in availability, with corresponding decreases in required maintenance and the occurrence of failures. Information was obtained on a variety of commercial and industrial facility types (including office buildings, hospitals, water treatment facilities, prisons, utilities, manufacturing facilities, school universities and bank computer centers) with varying degrees of maintenance quality. See Annex Q for further details.

In order to collect statistically valid data it was important that a stratified survey of different facility categories, applications, and operating conditions be conducted. Guidelines were developed to assist in the selection of potential sites. These guidelines include:

1) Locations surveyed were required to have varying degrees of maintenance practices.
2) A number of sites for each facility category was predetermined; this was required to eliminate any skewing of the data caused by the influence of limited data.
3) Component size was a basis of site selection to ensure that similar technologies were being compared.
4) Equipment age was considered to ensure that data from both the newer high-efficiency generation of equipment and the older technology generation were not mixed.

The first of these was included because it is known that maintenance policies and practices directly affect equipment availability. High levels of maintenance lower availability but have the potential to increase reliability. Too little maintenance raises availability but has the potential to decrease reliability. During a prolonged period of operation time with little maintenance, availability and reliability both decrease drastically. The amount of maintenance performed can drastically affect the performance parameters being collected.

A process of identification and certification of data was developed to ensure that each data collection trip was successful. Minimum requirements for data were established to ensure a sound statistical basis for the analysis, as follows:

- A minimum of 5 years of operational data were collected
- Minimum sample size of 40 with a maximum site allocation of 10 items each
- A minimum of 3.5 million operating hours total for each component

Knowledge of the reliability of electrical equipment is an important consideration in the design and operation of industrial and commercial power distribution systems. The failure characteristics of individual pieces of electrical equipment (i.e., components) can be partially described by the following basic reliability statistics:

- Failure rate, often expressed as failures per year per component (failures per unit-year);
- Downtime to repair, replace or maintain a component after it has failed in service or required preventive maintenance, expressed in hours per failure;
- The reliability, inherent availability (Ai), and operational availability (Ao) are also expressed as a numerical probability.

Electrical equipment reliability data was obtained from field surveys of individual industrial and commercial equipment failure reports. The reason for conducting this survey was to provide answers to critical questions pertaining to the failure characteristics of electrical equipment in industrial and commercial installations. Each survey has a defined objective of obtaining field data on electrical equipment failure characteristics, and this determines the form of the questionnaires that are sent to various respondents.

An analysis of the survey returns may or may not provide answers to all questions posed in the questionnaire. The significance of the surveyed data obtained is dependent upon many factors, for example, the number of equipment failures reported, their operating history, and the survey questionnaire. There will undoubtedly be new questions raised and also some old questions and controversies left unresolved. Items found to be of little significance will be omitted and the survey form simplified to maximize the response for the next survey. The procedure for conducting the survey is given in Annex F. Information on the determination and analysis of reliability studies is presented in IEEE Std 500™-1984 [B15].[1]

The IEEE Industry Applications Society (IAS) has a continuing program to conduct surveys on the reliability of electrical equipment in industrial and commercial installations (see Dickinson [B5], IEEE Committee Reports [B10], [B11], [B12], [B13], [B14], and O'Donnell [B18], [B19]). The most significant results from these surveys are then summarized for inclusion in a future revision of this recommended practice.

As in previous survey reports, this chapter maintains the standard for credibility of failure rates by identifying categories that contain an insufficient number of failures. If there were less than eight failures, a footnote indicates a small sample size. It is believed that a minimum of eight field failures is necessary to have a reasonable chance of estimating the failure rate or the average downtime per failure to within a factor of two (see Annex A, Part I for details). Both the average downtime per failure data and median downtime per

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[1] The numbers in brackets correspond to those of the bibliography in 10.5.

failure data are given so that the effect of a few very long outages on the average downtime can be indicated by a large difference between the average and median values.

An equipment reliability reference guide is shown in Table 10-1. For each electrical component presented in Parts 2 and 3 of this chapter, the tables and annexes that contain reliability data pertinent to that component are presented. Table 10-2 contains a summary of the failure rate and average and median downtime per failure data for all electrical equipment surveyed contained in Parts 2 and 3. These values are suggested for use in the absence of better data being available from the reader's own experience. This information is applicable to Parts 2 and 3 only. Part 1 contains reliability and maintainability information in Table 10-4.

Table 10-1—Equipment reliability reference guide

Electrical equipment		Reference tables in Chapter 10											Annexes
		Part 2				Part 3							
		Surveys 1976–1989				Surveys prior to 1976							
Motors	> 50 hp	24									36		A, B, H
	> 200 hp	17–23									36		
	> 250 hp	27									36		
Motor starters							31	32	33	34	36	37	A, B
Generators		6									36		A, B, G
Trans-formers	Power	7	9	10	11						36	37	
		12	13	14	15								
	Rectifier	8	10	11	12						36	37	
		13	14	15									
Circuit breakers		30				29		32	33	34	36	37	A, B, J, K, P
Disconnect switches							31	32	33	34	36	37	A, B
Bus duct							31	32	33	34	36		A, B

Table 10-1—Equipment reliability reference guide *(continued)*

Electrical equipment		**Reference tables in Chapter 10**								**Annexes**
		Part 2	**Part 3**							
		Surveys 1976–1989	**Surveys prior to 1976**							
Switch-gear	Bus insulated	5						36		A, B, E
	Bus bare	5						36		
Open wire				31	32	33	34	36	37	A, B
Cable				31	32	33	34	36	37	A, B, I
Cable joints				31	32	33	34	36	37	
Cable terminations				31	32	33	34	36	37	
Transmission lines 230 kV and above										N
Electric utility power supplies							35	36		A, B, D

Table 10-2—Summary of optional failure rate and average, and median downtime per failure, for all electrical equipment surveyed

Equipment	Equipment subclass	Failure rate (failures per unit-year)	Actual hours of downtime per failure	
			Industry average	Median plant average
Transformers	Liquid filled—All	0.0062	356.1[a]	—
	300 kVA to10 000 kVA	0.0059	297.4[a]	—
	10 000+ kVA	0.0153	1178.5[a]	—
Rectifier transformers	Liquid filled			
	300 kVA to10 000 kVA	0.0153	1664.0[a]	—
Motors > 200 hp[b]	Induction			
	0 to 1000 V	0.0824	42.5	15.0
	1001 V to 5000 V	0.0714	75.1	12.0
	Synchronous			
	1001 V to 5000 V	0.0762	78.9	16.0
Circuit breakers[c]	Fixed (including molded case)	0.0052	5.8	4.0
	0 to 600 V—All sizes	0.0042	4.7	4.0
	0 to 600 A	0.0035	2.2	1.0
	Above 600 A	0.0096	9.6	8.0
	Above 600 V[c]	0.0176	10.6	3.8
	Metal-clad drawout type—All	0.0030	129.0	7.6
	0 to 600 V—All sizes	0.0027	147.0[d]	4.0
	0 to 600 A	0.0023	3.2	1.0
	Above 600 A	0.0030	232.0	5.0
	Above 600 V[c]	0.0036	109.0[d]	168.0
Motor starters	Contact type: 0 to 600 V	0.0139	65.1	24.5
	Contact type: 601 V to 15 000V	0.0153	284.0	16.0
Generators	Continuous service			
	Steam turbine driven		32.7	—
	Emergency and standby units			
	Reciprocating engine driven	0.1691		
	Rate per hour in use (0.00536)			—
	Failures per start attempt (0.0135)		478.0	
Disconnect switches	Enclosed	0.006100	1.6	2.8

Table 10-2—Summary of optional failure rate and average, and median downtime per failure, for all electrical equipment surveyed *(continued)*

Equipment	Equipment subclass	Failure rate (failures per unit-year)	Actual hours of downtime per failure	
			Industry average	Median plant average
Switchgear bus—Indoor and outdoor[e]	Insulated: 601 V to 15000 V	0.001129	261.0	28.0
	Bare: 0 to 600 V	0.000802	550.0	27.0
	Bare: Above 600 V	0.001917	17.3	36.0
Bus duct Indoor and outdoor (unit = 1 circuit ft)	All voltages	0.000125	128.0	9.5
Open wire (unit = 1000 circuit ft)	15 000 V	0.01890	42.5	4.0
	Above 15 000 V	0.00750	17.5	12.0
Cable—All types of insulation (unit = 1000 circuit ft)[f]	Aboveground and aerial			
	0 to 600 V	0.001410	457.0	10.5
	601 V to 15 000 V—All	0.014100	40.4 [d]	6.9
	In trays aboveground	0.009230	8.9	8.0
	In conduit aboveground	0.049180	140.0	47.5
	Aerial cable	0.014370	31.6	5.3
	Belowground and direct burial			
	0 to 600 V	0.003880	15.0	24.0
	601 V to 15 000 V—All	0.006170	95.5 [d]	35.0
	In duct or conduit	0.006130	96.8	35.0
	Above 15000 V	0.003360	16.0	16.0
Cable (unit = 1000 circuit ft)	601 V to 15 000 V			
	Thermoplastic	0.00387	44.5	10.0
	Thermosetting	0.00889	168.0	26.0
	Paper-insulated lead-covered	0.00912	48.9	26.8
	Other	0.01832	16.1	28.5
Cable joints—All types of insulation	601 V to 15 000 V			
	In duct or conduit belowground	0.000864	36.1	31.2
Cable joints[f]	601 V to 15 000 V			
	Thermoplastic	0.000754	15.8	8.0
	Paper-insulated lead-covered	0.001037	31.4	28.0

Table 10-2—Summary of optional failure rate and average, and median downtime per failure, for all electrical equipment surveyed *(continued)*

Equipment	Equipment subclass	Failure rate (failures per unit-year)	Actual hours of downtime per failure	
			Industry average	Median plant average
Cable terminations[f] all types of insulation	Aboveground and aerial			
	0 to 600V	0.000127	3.8	4.0
	601 V to 15 000 V—All	0.000879	198.0	11.1
	Aerial cable	0.001848	48.5	11.3
	In trays aboveground	0.000333	8.0	9.0
	In duct or conduit below-ground			
	601 V to 15 000 V	0.000303	25.0	23.4
Cable terminations	601 V to 15 000 V			
	Thermoplastic	0.004192	10.6	11.5
	Thermosetting	0.000307	451.0	11.3
	Paper-insulated lead-covered	0.000781	68.8	29.2
Miscellaneous	Inverters	1.254000	107.0	185.0
	Rectifiers	0.038000	39.0	52.2

[a] See Table 10-7 and Table 10-8 in this chapter for data comparing replacement time with average repair time of transformers.

[b] See Table 10-26 for motors > 50 hp.

[c] See Annex J for circuit breakers above 63 kV from a CIGRE 13-06 worldwide survey. See Annex K for a later small IEEE survey.

[d] See Tables 50, 51, 55, and 56 in Annex B for results on a special study on effects of failure repair method and failure repair urgency on the average hours downtime per failure.

[e] Unit = the number of connected circuit breakers and connected switches.

[f] See Annex I for utility industry data on underground cable, terminations, and splices.

10.2 Part 1: Mechanical and electrical equipment reliability and availability data collection conducted between 1990 and 1993

10.2.1 Data collection process

10.2.1.1 Database development

A computerized system named Power Reliability Enhancement Program Information System (PREPIS) was developed to assist technical staff in organizing, tracking, analyzing, and reporting all of the technical and contact information during the execution of this U.S. Army Corp of Engineers, Power Reliability Enhancement Program (PREP) project. The three major components in PREPIS are:

a) Contact records: Contains site information; it is comprised of 6208 contact records.
b) Equipment records: Contains performance and maintenance information; it includes 4043 equipment records.
c) A comprehensive database system organized functionally to support the following tasks:
    1) Record individual site information
    2) Prioritize site visits
    3) Collect and organize site data
    4) Data input and verification
    5) Data summarization and analysis
    6) Report generation

The output record generator contains several "canned" reports designed for data summary and availability calculations. Some of the reports are designed to allow the user the flexibility to select a multitude of query topics. The format of the report generator allows easy construction of custom reports for individual needs.

This database, developed in 1991, was adequate for the task. As new, more efficient database tools were developed, it became apparent that a more portable, user-friendly database tool was needed. In addition several inquiries of the database resulted in a significant effort to recreate data reports to satisfy requests. A better method was sought to minimize this time.

Alion Science and Technology began the arduous task in 1998 of creating a common database and has transferred the data into currently available database software, allowing the user the ability to develop customized data extraction scenarios on a PC. The database can now be placed on a CD and transferred to anyone with database software.

10.2.1.2 Database Information

In order to collect statistically valid data it was important that a stratified survey of different facility categories, applications and operating conditions be conducted. Guidelines were developed to assist in the selection of potential sites. These guidelines include:

a) Locations surveyed were required to have varying degrees of maintenance practices.
b) A number of sites for each facility category were predetermined; this was required to eliminate any skewing of the data caused by the influence of limited data.
c) Component size was also a basis of site selection to ensure that similar technologies were being compared.
d) Equipment age was also considered to ensure that data from both the newer high-efficiency generation of equipment and the older technology generation were included.

The first of these was included because it is known that maintenance policies and practices directly affect equipment availability. High levels of maintenance lower availability, but have the potential to increase reliability. Too little maintenance raises availability, but has the potential to decrease reliability. During a prolonged period of operation time with little maintenance, availability and reliability both decrease drastically. The amount of maintenance performed can drastically affect the performance parameters being collected.

A process of identification and certification of data was developed to ensure that each data collection trip was successful. Minimum requirements for data were established to ensure a sound statistical basis for the analysis; a minimum of 5 years of operational data was collected with a minimum sample size of 40, with a maximum site allocation of 10 items each was imposed. This resulted in an estimated 3.5 million calendar hours total for each component and was the established baseline for each component.

10.2.1.3 Data contacts

Contacts were the key to the success of this program. The cooperation and support of the people involved from the many facilities, even during times of budget and personnel reduction, is demonstrated in the quality of data received to support the PREP.

A concerted effort was employed to develop an extensive contact database using manufacturers, facilities, societies, and locations of any potential data contributor utilizing PREP components. Manufacturers were contacted not only for contacts, but also for any warranty data that may be available. A total of 25 manufacturers participated. A total of 25 professional societies were contacted, including: American Gas Association, National Association of Power Engineers, American Society of Mechanical Engineers, Association of Physical Plant Administrators, and Association of Energy Engineers.

10.2.2 Data summarization and classification

10.2.2.1 Data Completeness

As with every data collection program, there are varying degrees of completeness in the data gathered. Some data sources had complete records and could give statistics on operational characteristics on every piece of equipment from installation date to that current moment of time. More often, the only items tracked were major items such as cooling towers and boilers. Data for items such as valves and filters were not usually recorded. Other problems included incomplete or non-current versions of the equipment's blue prints. Several Alion Science and Technology technicians manually developed parts lists, recording data from nameplates and relying on facility engineers for component descriptions.

It became important to categorize the different levels of data completeness to ensure that the final data collection included fair data representation for each component. To quantify this data completion (or quality) index, Alion Science and Technology identified these four levels:

a) *Perfect data:* Data needed for a valid, complete reliability study, including a parts list, failure history data with time to failure statistics, parts description data, operational periods, and 10 continuous years of recorded data. No engineering judgment or data extrapolation is required. The PREPIS equipment record database is comprised of 10% to 20% of this type of data.

b) *Not perfect data:* Data with no serious flaws, but the data collection process demanded additional time to ensure useful information was gathered. Examples include parts list determined by inspection, incomplete blueprints, or less than 10 years of data. The PREPIS equipment record database contains 35% to 40% of this type of data.

c) *Verbal/inspection data*: Data with serious gaps that required additional documentation and verification prior to its inclusion in the database. Items included were typically major items, such as generator sets and boilers. Senior maintenance personnel were interviewed to extract the necessary information to fill the data gaps. These interviews were used as support documentation to recorded data, not as data source information. About 25% of this type of data exist in the PREPIS equipment record database.

d) *Soft data:* Data that relied on the memories of experienced maintenance personnel from the participating facility; it was often extracted from log books containing maintenance personnel entries, filing cabinets with work order forms, and repair records when outside repair support was needed. Engineering judgment was often used to determine numerous performance parameters. This type of data was the most difficult and time consuming to summarize and was only used when no other data sources were available. The PREPIS equipment record database is comprised of 10% to 15% of this type of data.

10.2.2.2 Maintenance Policy

The major intent of the data collection effort was to minimize the effects of maintenance policies and procedures on the calculated availability values by collecting data from a variety of locations having various maintenance policies. Alion Science and Technology personnel developed a code to categorize each facility's maintenance policies and procedures into one of three levels:

a) *Code 1:* Above average maintenance policy. The facility not only followed a scheduled, preventive maintenance policy that was equivalent or similar to the manufacturer's suggested policy, but also went beyond it, such as using redundant units, specialized equipment tests (thermograph, vibration analysis, oil analysis), complete spare parts kits for equipment, and so on.

b) *Code 2:* Average maintenance policy. Facility used either in-house maintenance crews performing scheduled, preventative maintenance according to the equipment manufacturer's suggested preventive maintenance schedule or a combination of in-house maintenance crews and outside contractors. In both cases, it was verified that they did actually follow a fairly rigid schedule.

c) *Code 3:* Below average maintenance policy. Facility's actual policy was less than average. It may have instituted a scheduled maintenance policy but not followed it or it may have had no maintenance policy. Symptoms such as leaky valves with

> rags tied around them, dirty air filters, squeaky bearings, loose belts, and lax general housekeeping because of unavailable manpower were typical signs that maintenance at a facility was less than desirable.

Each location was then compared to each other and to the average maintenance policy. Overall, the facilities that Alion Science and Technology visited practiced an average level of maintenance; that is, they adhered to the manufacturer's recommended maintenance policy. Alion Science and Technology looked at approximately the same number of facilities that had below average maintenance policies as those facilities that had an above average maintenance policy.

Table 10-3 contains the maintenance code for the collected information found in Table 10-4.

Table 10-3—Maintenance codes

Code 1	Above average	25%
Code 2	Average	58%
Code 3	Below average	17%

10.2.3 Results

Annex Q includes the 204 components representing the PREP database. It is presented in a hierarchical structure to provide the analyst with numeric options if the exact component is not identified. As an example, the *category* of Accumulator is comprised of two *classes* (pressurized and unpressurized). Each of the classes is comprised of individual data points. Reliability numeric is derived for each data point listed within a class and displayed in columns in the database report.

The numeric is then rolled up to the class level to indicate a combination of information within each class. Subsequently the data from the class level is rolled up into the category level. The reliability numeric becomes more generically applied to the item as the information is rolled-up to the next higher level. Where we had various sizes, for example transformer capacities, information was combined to create a general transformer number.

Table 10-4 is provided to help the reader understand and properly apply the data categories in the analysis. The summary information calculated from the individual equipment records is also included.

Table 10-4 contains a summary of Ai and reliability information. The table includes the data points adhering to the data reporting requirements of the *IEEE Gold Book*™ referenced in Annex A, Part I. In addition, other components that did not meet the criterion of eight or more failures are included in Table 10-4 and are also included in Annex Q.

Table 10-4— Inherent availability and reliability data

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
Accumulator				1373.3	9	0.00655	1336648	8.22	0.8375	0.88
	Pressurized			982.8	6	0.0061	1434920	11.33	0.8555	0.897
	Item:	H1-000	Accumulator, pressurized.	982.8	6	0.0061	1434920	11.33	1	0.897
	Unpressurized			390.4	3	0.00768	1140104	2	0.3333	0.421
	Item:	H1-200	Accumulator, unpressurized.	390.4	3	0.00768	1140104	2	0	0.421
Air com-pressor				799.9	29	0.03625	241630.34	8.12	0.3086	0.326
	Electric			315.7	24	0.07601	115246	9.27	0.1602	0.178
	Item:	H2-100	Air compressor, electric	315.7	24	0.07601	115246	9.27	0	0.178
	Fuel			484.2	5	0.01033	848275.2	2.6	2.0028	2.006
	Item:	H2-200	Air compressor, fuel	484.2	5	0.01033	848275.2	2.6	2	2.006
Air dryer				437.4	1	0.00229	3831360	5	0.9326	0.946
	All types			437.4	1	0.00229	3831360	5	0.9326	0.946
	Item:	H4-000	Air dryer, all types	437.4	1	0.00229	3831360	5	1	0.946

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
Air-handling unit				1817.5	20	0.011	796075.2	2.36	xxx	99.036
	Non-humid wo/drive			1817.5	20	0.011	796075.2	2.36	xxx	99.036
	Item:	H5-200	Air-handling unit, non-humid wo/drive	1817.5	20	0.011	796075.2	2.36	0	99.036
Arrester				1513.5	2	0.00132	6629340	4	xxx	4
	Lightning			1513.5	2	0.00132	6629340	4	xxx	4
	Item:	E1-000	Arrester, lightning	1513.5	2	0.00132	6629340	4	0	4
Battery				10543.8	74	0.00702	1248161.4	12.11	0.149	0.217
	Gel cell-sealed			2333.7	47	0.02014	434961.38	2	0.1318	0.152
	Item:	E2-110	Battery, gel cell-sealed, strings	2333.7	47	0.02014	434961.4	2	0	0.152
	Lead acid			3215.3	24	0.00746	1173590.3	32.13	0.1463	1.023
	Item:	E2-120	Battery, lead acid, strings	3215.3	24	0.00746	1173590.3	32.13	0	1.023
	Nickel-cadmium			4994.8	3	0.0006	14584865	10.33	0.1591	0.163
	Item:	E2-130	Battery, nickel-cadmium	4994.8	3	0.0006	14584865.3	10.33	0	0.163

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
Blower				2920.3	0	0.00017	50160988	xxx	0.0692	0.069
	Wo/drive			2920.3	0	0.00017	50160988	xxx	0.0692	0.069
	Item:	H7-100	Blower, wo/drive	2920.3	0	0.00017 [a]	50160988.2 [a]	0	0	0.069
Boiler				1113	144	0.12938	67708.833	43.29	3.2844	3.738
	Hot water			358.4	15	0.04186	209292.8	3.08	0.9848	1.005
	Item:	H8-100	Boiler, hot water, gravity and circulated	358.4	15	0.04186	209292.8	3.08	1	1.005
	Steam			754.6	129	0.17094	51245.581	47.96	3.6062	4.12
	Item:	H8-210	Boiler, steam, high pressure	468.6	35	0.07469	117277.7	44.63	3	3.162
	Item:	H8-220	Boiler, steam, low pressure	286.1	94	0.32859	26659.1	49.2	0	116.734
Bus duct				1679	0	0.0003	28838917	xxx	xxx	xxx
	All types			1679	0	0.0003	28838917	xxx	xxx	xxx
	Item:	E3-000	Bus duct, all types, per 100 ft	1679	0	0.0003	28838917.6 [a]	0	0	xxx
Cabinet heaters				9796.7	1	0.0001	85819128	0.5	1.6476	1.647
	Forced air flow			9796.7	1	0.0001	85819128	0.5	1.6476	1.647

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E4-100	Cabinet heaters, forced air flow, steam or hot water	9796.7	1	0.0001	85819128	0.5	2	1.647
Cable				736301.3	1364	0.00185	4728738.3	5.59	4.2595	4.361
	Aboveground			588927.8	289	0.00049	17851235	8.44	6.868	7.256
	Item:	E6-111	Cable, aboveground, in conduit, <=600 V, per 1000 ft	29442.9	2	0.00007	12895993	8	13	13.01
	Item:	E6-211	Cable, aboveground, in conduit, >600 V, per 1000 ft	523356.6	281	0.00054	16315315.2	8.56	41	16.109
	Item:	E6-113	Cable, aboveground, no conduit, <=600 V, per 1000 ft	33286.3	4	0.00012	72896904	2.5	0	0.078
	Item:	E6-214	Cable, aboveground, no conduit, >600 V, per 1000 ft	2646	2	0.00076	11589564	4	0	0.032
	Item:	E6-112	Cable, aboveground, trays, <=600 V, per 1000 ft	15.9	0	0.03204	273411.8 [a]	0	0	xxx
	Item:	E6-212	Cable, aboveground, trays, >600 V<=5 kV, per 1000 ft	180.1	0	0.00283	3093176.5 [a]	0	0	xxx
	Aerial			37478.5	438	0.01169	749570.95	2.03	xxx	1.907

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E7-100	Cable, aerial, <=15 kV, per mile	6593.7	311	0.04717	185725.9	1.82	0	1.817
	Item:	E7-200	Cable, aerial, >15 kV, per mile	30884.9	127	0.00411	2130325.4	2.54	0	2.081
	Belowground			109482.8	634	0.00579	1512727	6.77	4.1354	4.238
	Item:	E6-121	Cable, belowground, duct, <=600 V, per 1000 ft	40000.4	5	0.00012	70080729.6	16.4	1	2.789
	Item:	E6-222	Cable, belowground, duct, >600 V<=5 kV, per 1000 ft	39.4	0	0.01296 [a]	676000 [a]	0	0	xxx
	Item:	E6-122	Cable, belowground, in conduit, <=600 V, per 1000 ft	24413.2	49	0.00201	4364479.8	11.22	88	28.222
	Item:	E6-221	Cable, belowground, in conduit, >600 V, per 1000 ft	19525.5	46	0.00236	3718331	15.7	211	41.547
	Item:	E6-223	Cable, belowground, insulated, >5 kV, per 1000 ft	22508.1	454	0.02017	434296.5	5.13	4	4.007
	Item:	E6-123	Cable, belowground, insulated, 0 to 600 V, per 1000 ft	2996.3	80	0.0267	328089.9	7.6	0	7.6
	Insulated			412.2	3	0.00728	1203640	2	0	0.109

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E8-100	Cable, insulated, dc, per 1000 ft	412.2	3	0.00728	1203640	2	0	0.109
Cable connection				21574.5	8	0.00037	23624073	0.75	xxx	0.75
	Belowground			21574.5	8	0.00037	23624073	0.75	xxx	0.75
	Item:	E5-100	Cable connection, belowground, duct, <=600 V, per 1000 ft	21574.5	8	0.00037	23624073	0.75	0	0.75
Capacitor bank				567.6	99	0.17443	50221.333	2.3	10	2.743
	Power factor corrector			567.6	99	0.17443	50221.333	2.3	10	2.743
	Item:	E10-000	Capacitor bank, power factor corrector, (in kvar)	567.6	99	0.17443	50221.3	2.3	10	2.743
Charger				270	2	0.00741	1182768	0.5	0.1297	0.133
	Battery			270	2	0.00741	1182768	0.5	0.1297	0.133
	Item:	E11-000	Charger, battery	270	2	0.00741	1182768	0.5	0	0.133
Chiller				2021.9	239	0.1182	74109.901	12.62	1.0881	1.164
	Absorption			430.3	74	0.17199	50932.864	11.74	0.624	0.653
	Item:	H10-100	Chiller, absorption	430.3	74	0.17199	50932.9	11.74	1	0.653

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Centrifugal			544.7	25	0.04589	190872.1	14.52	5.2247	5.333
	Item:	H10-220	Chiller, centrifugal, 600 tons to 1000 tons	544.7	25	0.04589	190872.1	14.52	5	5.333
	Reciprocating			948.2	138	0.14554	60190.782	12.05	1.5457	1.837
	Item:	H10-321	Chiller, reciprocating, closed, w/drive, 50 tons to 200 tons	680.2	87	0.1279	68491.3	13.05	1	1.662
	Item:	H10-331	Chiller, reciprocating, open, wo/drive, 50 tons to 200 tons	268	51	0.19031	46031.1	10.35	3	3.611
	Rotary			76.4	1	0.01309	669120	24	6.0723	6.115
	Item:	H10-410	Chiller, rotary, 600 tons to 1000 tons	76.4	1	0.01309	669120	24	6	6.115
	Screw			22.4	1	0.0447	195984	96	1	1.164
	Item:	H10-520	Chiller, screw, >300 tons	22.4	1	0.0447	195984	96	1	1.164
Circuit breaker, 600 V				157040.9	52	0	26974078	xxx	1.9167	1.959
	3-phase, fixed			147880	5	0	25400557	xxx	8.2967	8.376

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E12-211	Circuit breaker, 600 V, 3-phase, fixed, including molded case, <=600 A, n.c., trp. ckt. inc.	32498.7	0	0.00002 [a]	55821363 [a]	0	3	3.098
	Item:	E12-212	Circuit breaker, 600 V, 3-phase, fixed, including molded case, <=600 A, n.o., trp. ckt. inc.	26597.8	3	0.00011	77665552	18.67	9	8.727
	Item:	E12-221	Circuit breaker, 600 V, 3-phase, fixed, including molded case, >600 A, n.c., trp. ckt. inc.	88200.2	0	0.00001 [a]	15149685 [a]	0	14	13.618
	Item:	E12-222	Circuit breaker, 600 V, 3-phase, fixed, including molded case, >600 A, n.o., trp. ckt. inc.	583.2	2	0.00343	2554428	37.5	3	3.034
	Drawout (metal clad)			7217.8	8	0.00111	7903437.1	3.13	2.0569	2.059
	Item:	E12-411	Circuit breaker, 600 V, drawout (metal clad), <600 A, normally closed trp., ckt. inc.	4809.3	1	0.00021	42129480	6	2	2.019

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E12-412	Circuit breaker, 600 V, drawout (metal clad), <600 A, normally open trp., ckt. inc.	785.4	2	0.00255	3440004	6	3	2.945
	Item:	E12-421	Circuit breaker, 600 V, drawout (metal clad), >600 A, normally closed trp., ckt. inc.	1080.4	2	0.00185	4732057.8	0.5	1	1.481
	Item:	E12-422	Circuit breaker, 600 V, drawout (metal clad), >600 A, normally open trp., ckt. inc.	542.7	3	0.00553	1584631.2	2	2	2.372
	Vacuum			1943.2	39	0.02007	436464	10.74	0.4031	0.48
	Item:	E12-711	Circuit breaker, 600 V, vacuum, <600 A, normally closed trp., ckt. inc.	355.6	1	0.00281	3114792	8	0	0.05
	Item:	E12-712	Circuit breaker, 600 V, vacuum, <600 A, normally open trp., ckt. inc.	458.2	0	0.00111 [a]	7870964.7 [a]	0	2	1.838
	Item:	E12-721	Circuit breaker, 600 V, vacuum, >600 A, normally closed trp., ckt. inc.	425.1	10	0.02352	372410.4	14.8	1	1.62

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E12-722	Circuit breaker, 600 V, vacuum, >600 A, normally open trp., ckt. inc.	704.2	28	0.03976	220321.7	9.39	0	0.492
Compressor				1255.3	17	0.01354	646853.64	8.68	0.9208	1.011
	Refrigerant			1037.8	5	0.00482	1818196.8	3.5	0.911	0.925
	Item:	H11-020	Compressor, refrigerant, >1 ton	1037.8	5	0.00482	1818196.8	3.5	1	0.925
	Screw type			217.5	12	0.05517	158794	10.83	0.9372	1.154
	Item:	H11-100	Compressor, screw type	217.5	12	0.05517	158794	10.83	1	1.154
Condensers				1102	116	0.10527	83216.689	7.17	4.0979	4.497
	Double tube			298.7	8	0.02678	327087	2.5	2.6323	2.628
	Item:	H12-100	Condensers, double tube	298.7	8	0.02678	327087	2.5	3	2.628
	Propeller type fans/coils			348.7	108	0.30976	28279.777	7.52	3.0905	4.165
	Item:	H12-200	Condensers, propeller type fans/coils, DX	348.7	108	0.30976	28279.8	7.52	3	4.165
	Shell and tube			454.6	0	0.00112	7808282.3	xxx	7.3493	7.349
	Item:	H12-300	Condensers, shell and tube	454.6	0	0.00112 [a]	7808282.4 [a]	0	7	7.349

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
Control panel				5643.4	30	0.00532	1647876	1.8	4.441	4.406
	Generator			1710.4	19	0.01111	788570.57	2.11	0.5703	0.635
	Item:	C4-100	Control panel, generator, wo/switchgear	1710.4	19	0.01111	788570.6	2.11	1	0.635
	HVAC/ chillers/AHU			3372.5	0	0.00015	57926964	xxx	1.0449	1.045
	Item:	C4-200	Control panel, HVAC/ chillers/AHU, wo/ switchgear	3372.5	0	0.00015 [a]	57926964.7 [a]	0	1	1.045
	Switchgear controls			560.6	11	0.01962	446426.18	1.27	7.0925	7.043
	Item:	C4-300	Control panel, switchgear controls	560.6	11	0.01962	446426.2	1.27	7	7.043
Convectors				5862.9	0	0.00009	10070423	xxx	0.0149	0.015
	Fin tube baseboard			5862.9	0	0.00009	10070423	xxx	0.0149	0.015
	Item:	H13-110	Convectors, fin tube, electric baseboard	1222.4	0	0.00042 [a]	20995811.8 [a]	0	0	0.005
	Item:	H13-120	Convectors, fin tube baseboard, steam or hot water	4640.6	0	0.00011 [a]	79708423.5 [a]	0	0	0.017

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
Cooling tower				839.1	27	0.03218	272229.73	80.89	1.0681	1.192
	Atmospheric type			323.7	24	0.07414	118158.45	88.92	0.9918	1.137
	Item:	H14-100	Cooling tower, atmospheric type, w/o fans, motors, pumps, valves, etc.	323.7	24	0.07414	118158.5	88.92	1	1.137
	Evaporative type			515.3	3	0.00582	1504800	16.67	1.4429	1.458
	Item:	H14-200	Cooling tower, evaporative type, w/o fans, motors, pumps, valves, etc.	515.3	3	0.00582	1504800	16.67	1	1.458
Damper assembly				18183.5	2	0.00003	31232804	xxx	0.054	0.054
	Motor			15416.3	0	0.00003	26479769	xxx	0.0497	0.05
	Item:	H15-100	Damper assembly, motor	15416.3	0	0.00003 [a]	26479769 [a]	0	0	0.05
	Pneumatic			2767.2	2	0.00072	12120240	2	4	3.882
	Item:	H15-200	Damper assembly, pneumatic	2767.2	2	0.00072	12120240	2	4	3.882

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
Diesel engine generator				1354.1	715	0.52802	16590.312	24.22	2.0554	2.642
	Packaged			938.1	238	0.25371	34527.712	23.14	1.1483	1.498
	Item:	E18-121	Diesel engine generator, packaged, 250 kW to 1.5 MW, continuous	266	155	0.58269	15033.8	25.74	1	1.149
	Item:	E18-122	Diesel engine generator, packaged, 250 kW to 1.5 MW, standby	672.1	83	0.1235	70932	18.28	2	1.748
	Unpackaged			416	477	1.14653	7640.415	24.76	3.2103	4.064
	Item:	E18-211	Diesel engine generator, unpackaged, 750 kW to 7 MW, continuous	180.6	328	1.81573	4824.5	25.08	4	4.997
	Item:	E18-212	Diesel engine generator, unpackaged, 750 kW to 7 MW, standby	235.4	149	0.63299	13839.2	24.05	3	3.106
Drive				2990.6	66	0.02207	396929.09	16.55	3.4472	6.218
	Adjustable speed			2990.6	66	0.02207	396929.09	16.55	3.4472	6.218

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E14-100	Drive, adjustable speed	2990.6	66	0.02207	396929.1	16.55	3	6.218
Evaporator				7922.3	32	0.00404	2168739	14.69	0.2565	0.277
	Coil			6911.4	29	0.0042	2087724.4	15.38	0.2689	0.29
	Item:	H18-100	Evaporator, coil, direct expansion	6911.4	29	0.0042	2087724.4	15.38	0	0.29
	Shell tube			1010.9	3	0.00297	2951880	8	0.1097	0.123
	Item:	H18-120	Evaporator, shell tube, direct expansion	1010.9	3	0.00297	2951880	8	0	0.123
Fan				2396.5	30	0.01252	699780	19.87	4.2211	4.372
	Centrifugal			782.8	15	0.01916	457179.2	24.47	1.6118	2.061
	Item:	H19-100	Fan, centrifugal	782.8	15	0.01916	457179.2	24.47	2	2.061
	Propeller/disc			384.1	4	0.01041	841188	35.5	1.8677	1.954
	Item:	H19-200	Fan, propeller/disc	384.1	4	0.01041	841188	35.5	2	1.954
	Tube axial			1087.8	11	0.01011	866290.9	7.91	11.4244	11.375
	Item:	H19-300	Fan, tube axial	1087.8	11	0.01011	866290.9	7.91	11	11.375
	Vane axial			141.8	0	0.0036	2434823.5	xxx	xxx	xxx
	Item:	H19-400	Fan, vane axial	141.8	0	0.0036 [a]	2434823.5 [a]	0	0	xxx

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
Filter				5047.9	0	0.0001	86704894	xxx	0.2894	0.289
	Electrical tempest			342.1	0	0.00149	5875341.1	xxx	0	0
	Item:	E16-200	Filter, electrical tempest	342.1	0	0.00149 [a]	5875341.2 [a]	0	0	0
	Mechanical			4705.8	0	0.00011	80829552	xxx	0.2894	0.289
	Item:	H20-100	Filter, mechanical, air regulator set	3187.2	0	0.00016 [a]	54745647.1 [a]	0	0	0.044
	Item:	H20-200	Filter, mechanical, fuel oil	699.5	0	0.00073 [a]	12014494.1 [a]	0	0	0.486
	Item:	H20-300	Filter, mechanical, lube oil	819.1	0	0.00062 [a]	14069411.8 [a]	0	1	1.439
Fuse				5902.1	483	0.08184	107043.77	4	xxx	4
	>15 kV			4756.7	483	0.10154	86270.211	4	xxx	4
	Item:	E17-300	Fuse, >15 kV (data suspect)	4756.7	483	0.10154	86270.2	4	0	4
	>5kV<= 15 kV			774.1	0	0.00066	13295858	xxx	xxx	xxx
	Item:	E17-200	Fuse, >5 kV<=15 kV	774.1	0	0.00066 [a]	13295858.8 [a]	0	0	xxx
	0 to 5 kV			371.3	0	0.00137	6377929.4	xxx	xxx	xxx

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E17-100	Fuse, 0 to 5 kV	371.3	0	0.00137 [a]	6377929.4 [a]	0	0	xxx
Gas turbine generator				921.5	400	0.4341	20179.8025	22.38	2.1583	2.419
	Packaged			750.9	399	0.53139	16485.055	21.6	2.1103	2.366
	Item:	E19-111	Gas turbine generator, packaged, 750 kW to 7 MW, continuous	167.9	290	1.7276	5070.6	27.39	1	1.225
	Item:	E19-112	Gas turbine generator, packaged, 750 kW to 7 MW, standby	583	109	0.18696	46853.7	6.18	4	4.453
	Unpackaged			170.6	1	0.00586	1494384	336	4.5892	5.146
	Item:	E19-211	Gas turbine generator, unpackaged, 750 kW to 7 MW, continuous	170.6	1	0.00586	1494384	336	5	5.146
Gauge				532.2	0	0.00096	9140564.7	xxx	xxx	xxx
	Fluid level			532.2	0	0.00096	9140564.7	xxx	xxx	xxx
	Item:	C5-100	Gauge, fluid level	532.2	0	0.00096 [a]	9140564.7 [a]	0	0	xxx
Heat exchanger				634.9	7	0.01103	794489.14	2.14	1.8371	1.838
	Boiler system			210	6	0.02857	306624	0.5	29.2586	28.3
	Item:	H21-100	Heat exchanger, boiler system, steam	210	6	0.02857	306624	0.5	29	28.3

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Lube oil			293.3	1	0.00341	2569488	12	6.536	6.59
	Item:	H21-200	Heat exchanger, lube oil	293.3	1	0.00341	2569488	12	7	6.59
	Water to water			131.5	0	0.00388	2259200	xxx	0.0544	0.054
	Item:	H21-400	Heat exchanger, water to water	131.5	0	0.00388 [a]	2259200 [a]	0	0	0.054
Heater				317.3	17	0.05358	163483.76	2.59	1.2053	1.207
	Electric			317.3	17	0.05358	163483.76	2.59	1.2053	1.207
	Item:	E24-110	Heater, electric, lube/ fuel oil or jacket	317.3	17	0.05358	163483.8	2.59	1	1.207
Humistat				643.3	10	0.01554	563551.2	1	0	0.043
	Assembly			643.3	10	0.01554	563551.2	1	0	0.043
	Item:	H24-000	Humistat, assembly	643.3	10	0.01554	563551.2	1	0	0.043
Inverters				414.8	2	0.00482	1817016	26	5.1691	5.321
	All types			414.8	2	0.00482	1817016	26	5.1691	5.321
	Item:	E25-000	Inverters, all types	414.8	2	0.00482	1817016	26	5	5.321
Meter				16557.7	18	0.00109	8058086.6	48.44	0.0055	1.182
	Electric			13702.4	5	0.00036	24006614.4	1	0	0.025

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	C6-100	Meter, electric	13702.4	5	0.00036	24006614.4	1	0	0.025
	Fuel			216.2	12	0.0555	157844	72	xxx	72
	Item:	C6-200	Meter, fuel	216.2	12	0.0555	157844	72	0	72
	Water			2639.1	1	0.00038	23118360	3	0.0075	0.013
	Item:	C6-300	Meter, water	2639.1	1	0.00038	23118360	3	0	0.013
Motor generator set				435.4	11	0.02526	346741.09	7.45	0.8368	0.839
	3-phase, 400 Hz			202.6	1	0.00494	1774344	8	2.8722	2.895
	Item:	E27-120	Motor generator set, 3-phase, 400 Hz	202.6	1	0.00494	1774344	8	3	2.895
	3-phase, 60 Hz			232.9	10	0.04295	203980.8	7.4	0.822	0.824
	Item:	E27-110	Motor generator set, 3-phase, 60 Hz	232.9	10	0.04295	203980.8	7.4	1	0.824
Motor starter				597.7	1	0.00085	10265882	xxx	0.2442	0.266
	<=600V			278.1	0	0.00183	4776705.8	xxx	0.0814	0.081
	Item:	E28-100	Motor starter, <=600 V	278.1	0	0.00183 [a]	4776705.9 [a]	0	0	0.081
	>600V			319.6	1	0.00313	2799480	24	0.3683	0.406

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E28-200	Motor starter, >600 V	319.6	1	0.00313	2799480	24	0	0.406
Motor, electric				27880.2	27	0.00097	9045589.3	241.52	0.5662	0.921
	DC			754.8	11	0.01457	601071.27	582	0.4228	0.904
	Item:	E29-100	Motor, electric, dc	754.8	11	0.01457	601071.3	582	0	0.904
	Induction			712.5	13	0.01825	480090.46	3.38	2.9576	2.967
	Item:	E29-210	Motor, electric, induction, <=600 V	361.4	4	0.01107	791448	1	1	1.336
	Item:	E29-220	Motor, electric, induction, >600 V	351.1	9	0.02564	341709.3	4.44	3	3.311
	Single phase			26034.5	1	0.00002	44718136	xxx	0.6247	0.625
	Item:	E29-310	Motor, electric, single phase, <=5 A	25345.3	0	0.00002 [a]	43534240 [a]	0	0	0.491
	Item:	E29-320	Motor, electric, single phase, >5 A	689.3	1	0.00145	6037872	3	1	0.716
	Synchronous			378.5	2	0.00135	6500894.1	xxx	2.2088	2.576
	Item:	E29-410	Motor, electric, syn-chronous, <=600 V	147.8	0	0.00345 [a]	2538917.6 [a]	0	2	2
	Item:	E29-420	Motor, electric, syn-chronous, >600 V	230.7	2	0.00867	1010304	36	3	4.65

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
Motor, mechanical				1154.7	1885	1.63246	5366.1453	1.02	2.8441	2.212
	Diesel			129.6	13	0.1003	87334.153	4.06	3.2492	3.253
	Item:	E15-100	Motor, mechanical, diesel	129.6	13	0.1003	87334.2	4.06	3	3.253
	Gas			1025.1	1872	1.82617	4796.923	1	0.75	0.941
	Item:	E15-200	Motor, mechanical, gas	1025.1	1872	1.82617	4796.9	1	1	0.941
Pipe				383	7	0.01828	479265	2.71	4	3
	Flex			383	7	0.01828	479265	2.71	4	3
	Item:	H25-112	Pipe, flex, non-reinforced, >4 in	206.3	3	0.01454	602290.2	3.33	4	3.6
	Item:	H25-122	Pipe, flex, reinforced, >4 in	176.7	4	0.02264	386996.1	2.25	0	2.25
Piping				13042.9	12	0.00004	22403087	xxx	7.7177	7.728
	Refrigerant			11221	6	0.00005	19273661	xxx	3.0645	3.199
	Item:	H25-310	Piping, refrigerant, <1 in	6850.6	0	0.00007 [a]	11766837 [a]	0	4	3.67
	Item:	H25-320	Piping, refrigerant, 1 in to 3 in, per 100 ft	3370.4	6	0.00282	3104080	10.67	1	0.932

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Water			1821.9	6	0.00028	31294258	xxx	xxx	8.008
	Item:	H25-410	Piping, water, <=2 in	437.3	0	0.00117 [a]	7510917.6 [a]	0	0	xxx
	Item:	H25-450	Piping, water, >12 in	8.2	0	0.06253 [a]	140094.1 [a]	0	0	xxx
	Item:	H25-420	Piping, water, >2<=4 in	292.3	6	0.02053	426692	14.08	0	14.083
	Item:	H25-430	Piping, water, >4<=8 in	268.7	0	0.0019 [a]	4614729.4 [a]	0	0	xxx
	Item:	H25-440	Piping, water, >8<=12 in	815.6	0	0.00063 [a]	14008611.8 [a]	0	8	8
Pressure control				721.3	5	0.00693	1263676.8	5.6	3.3935	3.492
	Assembly			721.3	5	0.00693	1263676.8	5.6	3.3935	3.492
	Item:	C8-000	Pressure control, assembly	721.3	5	0.00693	1263676.8	5.6	3	3.492
Pressure regulator				609.4	0	0.00084	10467090	xxx	0.5	0.5
	Hot gas			609.4	0	0.00084	10467090	xxx	0.5	0.5
	Item:	C9-100	Pressure regulator, hot gas	609.4	0	0.00084 [a]	10467090.2 [a]	0	0	0.5
Pump				1742.2	11	0.00631	1387387.6	7.09	0.4204	0.432

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Centrifugal			1376.8	8	0.00581	1507638	6.75	0.3372	0.353
	Item:	H26-110	Pump, centrifugal, integral drive	665.5	5	0.00751	1166025.6	7.4	1	0.599
	Item:	H26-120	Pump, centrifugal, wo/drive	711.3	3	0.00422	2076992	5.67	0	0.246
	Positive displacement			365.3	3	0.00821	1066720	8	0.5176	0.526
	Item:	H26-200	Pump, positive displacement	365.3	3	0.00821	1066720	8	1	0.526
Radiators				877.7	11	0.01253	698976	15.55	0.0999	0.15
	Small tube			877.7	11	0.01253	698976	15.55	0.0999	0.15
	Item:	H21-310	Radiators, small tube	877.7	11	0.01253	698976	15.55	0	0.15
Rectifiers				447.5	2	0.00447	1960032	16	3.4491	3.471
	All types			447.5	2	0.00447	1960032	16	3.4491	3.471
	Item:	E32-000	Rectifiers, all types	447.5	2	0.00447	1960032	16	3	3.471
Sending unit				36914.4	16	0.00043	20210622	9.38	0.017	0.045
	Air velocity			6179.6	7	0.00113	7733345.1	10	0.0156	0.034
	Item:	C13-100	Sending unit, air velocity	6179.6	7	0.00113	7733345.1	10	0	0.034

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Pressure			4314.2	9	0.00209	4199130.6	8.89	0.0208	0.076
	Item:	C13-200	Sending unit, pressure	4314.2	9	0.00209	4199130.7	8.89	0	0.076
	Temperature			26420.6	0	0.00002	45381247	xxx	xxx	xxx
	Item:	C13-300	Sending unit, temperature	26420.6	0	0.00002 [a]	45381247 [a]	0	0	xxx
Control systems				551	244	0.44282	19782.196	2.88	0.5615	0.855
	<=1000 acquisition points			373.9	94	0.25143	34841.106	1.6	1.2558	1.376
	Item:	C12-100	Software con. ADAS sys., <=1000 acquisition points	373.9	94	0.25143	34841.1	1.6	1	1.376
	>1000 acquisition points			177.1	150	0.84676	10345.28	3.68	0.4825	0.771
	Item:	C12-200	Software con. ADAS sys., >1000 acquisition points	177.1	150	0.84676	10345.3	3.68	0	0.771
Strainer				8996.1	0	0.00006	15452150	xxx	0.3084	0.308
	Coolant			447.8	0	0.00114	7691200	xxx	1.629	1.629
	Item:	H27-210	Strainer, coolant	447.8	0	0.00114 [a]	7691200 [a]	0	2	1.629
	Duplex fuel/ lube oil			117.8	0	0.00433	2023341.1	xxx	0.8614	0.861

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	H27-220	Strainer, duplex fuel/ lube oil	117.8	0	0.00433 [a]	2023341.2 [a]	0	1	0.861
	Fuel oil			413.2	0	0.00123	7098023.5	xxx	1.7094	1.709
	Item:	H27-230	Strainer, fuel oil	413.2	0	0.00123 [a]	7098023.5 [a]	0	2	1.709
	Lube oil			1084.3	0	0.00047	18624376	xxx	1.738	1.738
	Item:	H27-240	Strainer, lube oil	1084.3	0	0.00047 [a]	18624376.5 [a]	0	2	1.738
	Water			6933	0	0.00007	11908456	xxx	0.1288	0.129
	Item:	H27-251	Strainer, water, <=4 in	6378.3	0	0.00008 [a]	10955614 [a]	0	0	0
	Item:	H27-252	Strainer, water, >4 in	554.7	0	0.00092 [a]	9528423.5 [a]	0	3	3.168
Switch				9720.8	61	0.00628	1395966.7	4.2	1.5333	1.612
	Automatic transfer			1074.9	55	0.05117	171197.67	4.1	7.3553	6.49
	Item:	E34-110	Switch, automatic transfer, >600 A	690.3	22	0.03187	274853.5	1.64	34	20.891
	Item:	E34-120	Switch, automatic transfer, 0 to 600 A	384.6	33	0.0858	102093.8	5.74	0	1.28
	Disconnect			3330.5	1	0.00015	57205889	xxx	1.5473	1.547
	Item:	E34-211	Switch, disconnect, enclosed, <=600 V	842.1	0	0.00061 [a]	14464658.8 [a]	0	2	1.991

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E34-213	Switch, disconnect, enclosed	573.5	1	0.00174	5023755.6	1	2	1.51
			>5 kV							
	Item:	E34-212	Switch, disconnect, enclosed, >600 V<= 5 kV	247.6	0	0.00206 [a]	4253270.6 [a]	0	2	2.4
	Item:	E34-222	Switch, disconnect, fused, dc, >600 A	861.5	0	0.00059 [a]	14797364.7 [a]	0	0	0
	Item:	E34-221	Switch, disconnect, fused, dc, 0 to 600 A	805.8	0	0.00063 [a]	13840094.1 [a]	0	1	0.548
	Electric			3115.2	2	0.00064	13644684	1	0.0093	0.014
	Item:	E34-310	Switch, electric, on/ off breaker type, non-knife	3115.2	2	0.00064	13644684	1	0	0.014
	Float			437.5	1	0.00229	3832560	2	0.1869	0.193
	Item:	E34-400	Switch, float, electric	437.5	1	0.00229	3832560	2	0	0.193
	Manual transfer			585.4	0	0.00087	10054305	xxx	1.4786	1.479
	Item:	E34-510	Switch, manual transfer, <=600 A	244.8	0	0.00208 [a]	4205411.8 [a]	0	1	1.098
	Item:	E34-520	Switch, manual transfer, >600 A	340.5	0	0.0015 [a]	5848894.1 [a]	0	3	2.88

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Oil filled			289.8	0	0.00176	4978494.1	xxx	8	8
	Item:	E34-610	Switch, oil filled, >=5 kV	289.8	0	0.00176 [a]	4978494.1 [a]	0	8	8
	Static			887.5	2	0.00225	3887220	13	2.039	2.113
	Item:	E34-830	Switch, static, >1000 A	271.7	1	0.00368	2380392	24	3	3.584
	Item:	E34-820	Switch, static, >600<=1000 A	130	1	0.00769	1138728	2	0	0.078
	Item:	E34-810	Switch, static, 0 to 600 A	485.8	0	0.00105 [a]	8343764.7 [a]	0	0	0.032
Switchgear				4558.7	37	0.00812	1079291.9	27.56	3.449	3.646
	Bare bus			3239	33	0.01019	859808.33	27.27	3.7329	3.993
	Item:	E36-110	Switchgear, bare bus, <=600 V, all cabinets, ckt. bkrs. not included	1791.3	17	0.00949	923068.2	7.29	4	4.308
	Item:	E36-130	Switchgear, bare bus, >5 kV, all cabinets, ckt. bkrs. not included	780.2	14	0.01794	488208.8	2.27	1	1.296
	Item:	E36-120	Switchgear, bare bus, >600 V<=5 kV, all cabinets, ckt. bkrs. not included	667.4	2	0.003	2923296	372	10	14.27
	Insulated bus			1319.6	4	0.00039	22666917	xxx	2.9046	2.975

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E36-210	Switchgear, insulated bus, <=600 V, all cabinets, ckt. bkrs. not included	322.7	0	0.00158 [a]	5543247.1 [a]	0	3	3.182
	Item:	E36-230	Switchgear, insulated bus, >5 kV, all cabinets, ckt. bkrs. not included	732.5	3	0.0041	2139024	37.33	14	14.434
	Item:	E36-220	Switchgear, insulated bus, >600 V<=5 kV, all cabinets, ckt. bkrs. not included	264.4	1	0.00378	2316000	8	1	0.774
Tank				1978.9	8	0.00404	2166924	18.13	0.1221	0.172
	Day			384.4	2	0.0052	1683600	5	0.3074	0.346
	Item:	E37-210	Tank, day, genset fuel	384.4	2	0.0052	1683600	5	0	0.346
	Fuel			309	2	0.00647	1353576	60	1.2584	1.911
	Item:	E37-220	Tank, fuel	309	2	0.00647	1353576	60	1	1.911
	Receiver			734.4	2	0.00272	3216840	7	0.0029	0.01
	Item:	E37-110	Tank, receiver	734.4	2	0.00272	3216840	7	0	0.01
	Water			551.1	2	0.00363	2413680	0.5	0.126	0.128
	Item:	E37-230	Tank, water	551.1	2	0.00363	2413680	0.5	0	0.128
Thermostat				6538.9	11	0.00168	5207323.6	3.14	0.7895	0.969

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Radiator			6538.9	11	0.00168	5207323.6	3.14	0.7895	0.969
	Item:	C15-100	Thermostat, radiator	6538.9	11	0.00168	5207323.6	3.14	1	0.969
Transducer				23687.4	42	0.00002	40686583	xxx	0.0183	0.019
	Flow			154.9	0	0.00329	2660941.1	xxx	0.36	0.36
	Item:	C16-100	Transducer, flow	154.9	0	0.00329 [a]	2660941.2 [a]	0	0	0.36
	Pressure			791.9	2	0.00253	3468708	2	0.6983	0.72
	Item:	C16-200	Transducer, pressure	791.9	2	0.00253	3468708	2	1	0.72
	Temperature			22740.5	40	0.00176	4980177	0.25	0.0119	0.013
	Item:	C16-300	Transducer, temperature	22740.5	40	0.00176	4980177	0.25	0	0.013
Trans- former, dry				11025.1	19	0.00005	18937280	xxx	3.2263	3.693
	Air cooled			4329	0	0.00012	74357512	xxx	4.2724	4.272
	Item:	E38-111	Transformer, dry, air cooled, <=500 kVA	2267.4	0	0.00022 [a]	38946258.8 [a]	0	4	3.826
	Item:	E38-113	Transformer, dry, air cooled, >1500 kVA<= 3000 kVA	840.2	0	0.00061 [a]	14432242.4 [a]	0	4	4.206

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E38-112	Transformer, dry, air cooled, >500 kVA<= 1500 kVA	1221.4	0	0.00042 [a]	20979011.8 [a]	0	6	6
	Isolation			6696.1	19	0.00284	3087252.6	21.26	0.9286	2.519
	Item:	E38-121	Transformer, dry, isolation, delta wye, <600 V	6696.1	19	0.00284	3087252.6	21.26	1	2.519
Transformer, liquid				8819.2	46	0.00522	1679476.6	82.74	16.9047	17.588
	Forced air			2593	28	0.0108	811246.28	132.43	21.1758	22.066
	Item:	E38-212	Transformer, liquid, forced air, <=10 000 kVA	419.8	3	0.00715	1225880	248	23	23.677
	Item:	E38-211	Transformer, liquid, forced air, <=5000 kVA	1821.5	23	0.01263	693748.2	3.65	1	0.976
	Item:	E38-213	Transformer, liquid, forced air, >10 000 kVA<= 50 000 kVA	351.7	2	0.00569	1540524	1440	22	23.203
	Non-forced air			6226.1	18	0.00289	3030057.3	5.44	0.76	0.85
	Item:	E38-221	Transformer, liquid, non-forced air, <=3000 kVA	5407.8	6	0.00111	7895436	5	10	8.394

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	E38-223	Transformer, liquid, non-forced air, >10 000 kVA<= 50 000 kVA	627.6	11	0.01753	499773.8	6.09	1	0.648
	Item:	E38-222	Transformer, liquid, non-forced air, >3000 kVA<= 10000 kVA.	190.7	1	0.00524	1670904	1	3	2.5
UPS				553.1	4	0.00092	9499764.7	xxx	3.8	3.688
	Rotary			126.7	0	0.00402	2176564.7	xxx	6.1053	6.105
	Item:	E39-100	UPS, rotary	126.7	0	0.00402 [a]	2176564.7 [a]	0	6	6.105
	Small computer room floor			426.4	4	0.00938	933708	2	2.7317	2.667
	Item:	E39-200	UPS, small computer room floor	426.4	4	0.00938	933708	2	3	2.667
Valve				106073.6	183	0	18219692	xxx	0.7962	0.806
	3-way			1874.6	0	0.00027	32199388	xxx	0.5165	0.516
	Item:	H28-110	Valve, 3-way, diverting/sequencing	686.4	0	0.00074 [a]	11790070.6 [a]	0	0	0.015
	Item:	H28-120	Valve, 3-way, mixing control	1188.2	0	0.00043 [a]	20409317.6 [a]	0	1	1.02
	Ball			2653.5	2	0.00019	45578400	xxx	0.1577	0.164

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	H28-310	Valve, ball, n.c.	1054.9	0	0.00048 [a]	18119435.3 [a]	0	0	0.192
	Item:	H28-320	Valve, ball, n.o.	1598.6	2	0.00125	7002036	0.5	0	0.045
	Butterfly			17576.2	23	0.00131	6694253.2	3.26	0.5539	0.609
	Item:	H28-410	Valve, butterfly, n.c.	2789.5	23	0.00825	1062421.6	3.26	1	1.288
	Item:	H28-420	Valve, butterfly, n.o.	14786.8	0	0.00003 [a]	25398456 [a]	0	0	0.476
	Check			3877.1	1	0.00026	33963360	1	0.9136	0.914
	Item:	H28-500	Valve, check, n.c.	3877.1	1	0.00026	33963360	1	1	0.914
	Control			15904	1	0.00006	13931940	8	0.1091	0.111
	Item:	H28-610	Valve, control, n.c.	12854.8	1	0.00008	11260780	8	0	0.08
	Item:	H28-620	Valve, control, n.o.	3049.3	0	0.00017 [a]	52375670.6 [a]	0	0	0.234
	Expansion			1984.1	0	0.00026	34080094	xxx	xxx	xxx
	Item:	H28-700	Valve, expansion	1984.1	0	0.00026 [a]	34080094.1 [a]	0	0	xxx
	Gate			17394.5	3	0.00017	50792032	5.67	0.8333	1.135
	Item:	H28-810	Valve, gate, n.c.	1729.3	1	0.00058	15148344	1	1	0.603
	Item:	H28-820	Valve, gate, n.o.	15665.3	2	0.00013	68613876	8	2	2.429
	Globe			26248	0	0.00002	45084720	xxx	0.9954	0.995
	Item:	H28-910	Valve, globe, n.c.	20947.4	0	0.00002 [a]	35980272 [a]	0	1	0.997

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	H28-920	Valve, globe, n.o.	5300.5	0	0.0001 [a]	91044470.6 [a]	0	0	0.4
	Plug			15233.3	148	0.00972	901648.37	1.81	0.0476	1.592
	Item:	H28-A10	Valve, plug, n.c.	8845.9	123	0.0139	630001.6	1.37	0	1.174
	Item:	H28-A20	Valve, plug, n.o.	6387.4	25	0.00391	2238150.7	4	0	4
	Reducing			337.7	0	0.00151	5799905.8	xxx	0.4939	0.494
	Item:	H28-B10	Valve, reducing, makeup water	337.7	0	0.00151 [a]	5799905.9 [a]	0	0	0.494
	Relief			752	1	0.00133	6587760	2	0.1796	0.19
	Item:	H28-C00	Valve, relief	752	1	0.00133	6587760	2	0	0.19
	Suction			2238.4	4	0.00179	4902090	7.25	0.5358	0.698
	Item:	H28-D00	Valve, suction	2238.4	4	0.00179	4902090	7.25	1	0.698
Valve operator				9975.4	72	0.00722	1213674	10.71	1.0564	1.469
	Electric			3640.2	36	0.00989	885794	18.42	0.9823	1.4
	Item:	C17-100	Valve operator, electric	3640.2	36	0.00989	885794	18.42	1	1.4
	Hydraulic			68.2	6	0.08794	99616	3	2.1569	2.204

Table 10-4— Inherent availability and reliability data *(continued)*

Category			Class	Unit - years	Failures	Failure rate (failures/ year)	MTBF	MTTR	MTTM	MDT
	Item:	C17-200	Valve operator, hydraulic	68.2	6	0.08794	99616	3	2	2.204
	Pneumatic			6266.9	30	0.00479	1829941.6	3	0.9783	1.776
	Item:	C17-300	Valve operator, pneumatic	6266.9	30	0.00479	1829941.6	3	1	1.776
Voltage regulator				358.4	13	0.03627	241506.46	74.77	0.3333	2.523
	Static			358.4	13	0.03627	241506.46	74.77	0.3333	2.523
	Item:	E-40-100	Voltage regulator, static	358.4	13	0.03627	241506.5	74.77	0	2.523
Water-cooling coil				4730	2	0.00042	20717496	2.5	0.2558	0.26
	Fan coil unit			4730	2	0.00042	20717496	2.5	0.2558	0.26
	Item:	H29-100	Water-cooling coil, fan coil unit	4730	2	0.00042	20717496	2.5	0	0.26

NOTE 1—xxx = no data collected.

NOTE 2—Information from Department of the Army, TM 5-698-5, *Survey of Reliability and Availability Information for Power Distribution, Power Generation and HVAC Components for Commercial, Industrial and Utility Installations,* 22 July 2006.

[a] Upper single-sided confidence interval—0 failures.

10.3 Part 2: Equipment reliability surveys (1976–1989)

10.3.1 1979 switchgear bus reliability data

The reliability of switchgear bus in industrial and commercial applications was investigated in a 1979 survey (see IEEE Committee Report [B13] and Annex E) and the summarized failure rate and median outage duration time for the various subcategories of equipment are shown in Table 5-3. In this survey, the term *units* for a bus is defined as the total number of connected circuit breakers and connected switches. In the previous survey of 1974, the term *units* included the total number of connected circuit breakers or instrument transformer compartments. The total number of plants in the 1979 survey response was considerably greater than the 1974 survey; however the unit-year sample size was slightly less.

The 1974 survey generated some controversy concerning bare and insulated buses. As can be seen from Table 10-5, insulated bus equipment showed a significantly higher failure rate than bare bus above 600 V. An analysis of the 1974 database revealed that the majority of the data collected came from the petroleum/chemical industry. In the 1979 survey, the petroleum/chemical industry data was separated from the remaining industrial database and indicated that the number of reported failures in each category was dominated by the petroleum/chemical industries. The bare bus failure rate was significantly higher and the insulated bus failure rate lower in the 1979 survey than in the 1974 survey.

Table 10-5—Switchgear bus, indoor and outdoor, 1979 survey data

Industry	Equipment subclass	Failure rate (failures per unit-year)	Median hours downtime per failure
All	All	0.001050	28
All	Insulated, above 600 V	0.001129 (0.001700)	28 (26.8) [a]
All	Bare, all voltages	0.000977	28
All	Bare, 0 to 600 V	0.000802 (0.000340)	27 (24.0) [a]
All	Bare, above 600 V	0.001917 (0.000630)	36 (13.0) [a]
Petroleum/chemical	Insulated, above 600 V	0.002020	40
Petroleum/chemical	Bare, all voltages	0.002570	28
Petroleum/chemical	Bare, 0 to 600 V	0.002761	22
Petroleum/chemical	Bare, above 600 V	[b]	48

[a] Number in parentheses = the result from the 1974 survey.
[b] Small sample size, less than eight failures.

A comparison of the median downtime per failure in both surveys revealed no significant differences. It is important to emphasize that the duration of an outage is dependent on many factors, and without supplementary information on the operating procedures, maintenance type, spare parts inventory, etc., the data in these surveys should be viewed as general information.

Some important additional observations based on the 1979 survey are as follows:

a) Newer bus appears to experience a higher failure rate than older bus. This may be partly explained by improper installation, type of construction of new switchgear, etc., but is not completely consistent with the observation that failure rates are highly dependent on maintenance.

b) Outdoor bus shows a higher failure rate than indoor bus.

c) Primary and contributing causes of failures were investigated. Inadequate maintenance was one of the leading "suspected primary causes of failure" and exposure to contaminants (including dust, moisture, and chemicals) was the leading "contributing cause to failure." This tends to support the data showing outdoor bus with a relatively high failure rate.

d) The survey results on type of failures show a surprisingly high percentage of line-to-line failures, rather than line-to-ground.

10.3.2 1980 generator survey data

The results of the 1980 generator survey data (see IEEE Committee Report [B11]) are summarized in Table 10-6. A *unit* in this survey was defined to include the generator's driver and its ancillary equipment, including the device from which the generator's output is made available to the "outside" world. The term *unit-year* was defined as the summation of the running times reported for each generator.

Table 10-6—1980 generator survey data

Equipment subclass	Average downtime per failure (h)	Failure rate
Continuous service steam turbine driven	032.7	0.16900 failures per unit-year
Emergency and standby units reciprocating engines driven	478.0	0.00536 failures per hour in use
Reciprocating engines driven	[a]	0.01350 failures per start attempt

[a] Small sample size less than eight failures.

Two major categories (i.e., continuously applied units and emergency or standby applied units) emerged from an evaluation of the responses. All of the continuous units were steam turbine driven, and all of the emergency or standby units were reciprocating engine driven. An important point to note on the data for emergency and standby units: Failure to start for automatically started units was counted as a failure, whereas failure to start for manually started units was not counted as a failure.

10.3.2.1 Reliability/availability guarantees of gas turbine and combined cycle generating units

Many industrial firms are now purchasing gas turbine generating units or combined cycle units that include both a gas turbine and a steam turbine. In some cases, the specification contains a reliability/availability (R/A) guarantee. Annex N (see Ekstrom [B6]) contains one manufacturer's suggestion on how to write a R/A guarantee when purchasing such units; this is a very thorough description of the factors that need to be considered along with the necessary definitions. Annex N also contains some 1993 data on the R/A of gas turbine units that was collected by an independent data collection organization.

10.3.3 1979 Survey of the reliability of transformers

A survey published in 1973–1974 raised some interesting questions and created some controversy (see IEEE Committee Report [B9]). The most controversial items in this survey concerned the average outage duration time after a transformer failure in relation to the failure restoration method, and the comparatively high failure rate for rectifier transformers.

The 1979 survey form (see IEEE Committee Report [B10]) was improved considerably, taking lessons learned from the 1973–1974 version. Items felt to be of little significance in the past were omitted and the form was simplified to maximize the response. Data relating specifically to transformer reliability such as rating, voltage, age, and maintenance were included in the new form. The most significant categories in the failed unit data are the causes of failure, the restoration method, restoration urgency and the duration of failure, and the age at time of failure. The survey form of the 1979 survey (published in 1983) is shown in the Annex G.

10.3.3.1 Failure rate and restoration method for power and rectified transformers survey results

The survey response for power transformers is summarized in Table 10-7 and the survey response for rectifier transformers is summarized in Table 10-8.

Table 10-7—Power transformers (1979 survey)

Equipment subclass	Failure rate (failures per unit-year)	Average repair time (hours per failure)	Average replacement time (hours per failure)
All liquid filled	0.0062	356.1	85.1
Liquid filled 300 kVA to 10 000 kVA	0.0059	297.4	79.3
Liquid filled >10 000 kVA	0.0153	1178.5[a]	192.0[a]
Dry 300 kVA to 10 000 kVA	[a]	[a]	[a]

[a] Small sample size, less than eight failures.

Table 10-8—Rectifier transformers (1979 survey)

Equipment subclass	Failure rate (failures per unit-year)	Average repair time (hours per failure)	Average replacement time (hours per failure)
All liquid filled	0.0190	2316.0	41.4
Liquid filled 300 kVA to 10 000 kVA	0.0153	1644.0[a]	38.7[a]
Liquid filled >10 000 kVA	[a]	[a]	[a]

[a] Small sample size, less than eight failures.

The survey results for the liquid-filled power transformers compared favorably between the 1973–1974 and 1979 surveys: 0.0041 and 0.0062 failures per unit-year, respectively. The 1979 survey also confirmed the fact that the failure rate for rectifier transformers (i.e., 0.0190) is much higher than those for the other transformer categories (i.e., 0.0062). This may be due to the severe duties to which they were subjected and/or the harsh environments in which they are housed.

Table 10-7 and Table 10-8 include data on restoration time vs. restoration method. The data clearly indicates that the restoration of a unit to service by repair rather than replacement results in a much longer outage duration in every case. This is consistent with previous survey results. Despite this fact, in most categories a larger number of units were restored to service by repair. These results show the obvious benefits in having spares at the site or readily available. The data also provides some of the information necessary in the preparation of an economic justification for spares. The averages shown represent only those cases where restoration work was begun immediately. Those instances in which the repair or replacement was deferred were excluded to avoid distorting the average restoration time data.

10.3.3.2 Failure rate vs. age of power transformers

The survey response for power transformer failures as a function of their age is summarized in Table 10-9.

An examination of Table 10-9 reveals that the failure rates for power transformers was approximately equal in all three age groups. It can be seen that slightly higher failure rates for transformer units aged 1 year to 10 years and for units greater than 25 years may be attributable to "infant mortality" and to units approaching the end of their life, respectively.

Table 10-9—Failure rate vs. age of power transformers (1979 survey)

Equipment subclass (kVA)	Age[a] (years)	Number of units	Sample size (unit-years)	Number of failures[b]	Failure rate (failures per unit-year)
Liquid filled 300 to 10 000	1 to 10	638	2625.5	19	0.0072
Liquid filled 300 to 10 000	11 to 25	715	8846.5	47	0.0053
Liquid filled 300 to 10 000	>25	397	5938.0	36	0.0060
Liquid filled >10 000	1 to 10	27	144.0	0[c]	—
Liquid filled >10 000	11 to 25	28	283.5	7[c]	0.0246[c]
Liquid filled >10 000	>25	9	158.0	2[c]	0.0126[c]

[a] Age was the age of the transformer at the end of the reporting period.

[b] Relay or tap changer faults were not considered in calculation of failure rates or repair and replacement times.

[c] Small sample size; less than eight failures.

10.3.3.3 Failure-initiating cause

Table 10-10 summarizes the failure-initiating cause data for power and rectifier transformers. This table reveals that a large percentage of transformer failures were initiated by some type of insulation breakdown or transient overvoltages.

Table 10-10—Failure-initiating cause for power and rectifier transformers (1979 survey)

Failure-initiating cause	All power transformers		All rectifier transformers	
	Number of failures[a]	Percentage (%)	Number of failures	Percentage (%)
Transient overvoltage disturbance (switching surges, arcing ground fault, etc.)	18	16.4	2	13.3
Overheating	3	2.7	1	6.7
Winding insulation breakdown	32	29.1	2	13.3
Insulation bushing breakdown	15	13.6	1	6.7
Other insulation breakdown	6	5.5	3	20.0
Mechanical breaking, cracking, loosening, abrading, or deforming of static or structural parts	8	7.3	3	20.0
Mechanical burnout, friction, or seizing of moving parts	3	2.7	2	13.3
Mechanically caused damage from foreign source (digging, vehicular accident, etc.)	3	2.7	0	0.0
Shorting by tools or other metal objects	1	0.9	0	0.0
Shorting by birds, snakes, rodents, etc.	3	2.7	0	0.0
Malfunction of protective relay control device or auxiliary device	5	4.6	0	0.0
Improper operating procedure	4	3.6	0	0.0
Loose connection or termination	8	7.3	1	6.7
Others	1	0.9	0	0.0
Continuous overvoltage	0	0.0	0	0.0

Table 10-10—Failure-initiating cause for power and rectifier transformers (1979 survey) *(continued)*

Failure-initiating cause	**All power transformers**		**All rectifier transformers**	
	Number of failures[a]	**Percentage (%)**	**Number of failures**	**Percentage (%)**
Low voltage	0	0.0	0	0.0
Low frequency	0	0.0	0	0.0
Total	110	100.0	15	100.0

[a] Failure = initiating cause not specified for two failures.

10.3.3.4 Failure-contributing cause

Table 10-11 summarizes the failure-contributing cause for power and rectifier transformers. Normal deterioration from age and cooling medium deficiencies were reported to have contributed to a large number of both power and rectifier transformer failures.

Table 10-11—Failure-contributing cause for power and rectifier transformers (1979 survey)

Failure-contributing cause	**All power transformers**		**All rectifier transformers**	
	Number of failures[a]	**Percentage (%)**	**Number of failures**[b]	**Percentage (%)**
Persistent overloading	1	1.1	0	0
Abnormal temperature	5	5.5	1	7.1
Exposure to aggressive chemicals, solvents, dusts, moisture, or other contaminants	13	14.4	1	7.1
Normal deterioration from age	12	13.3	4	28.6
Severe wind, rain, snow, sleet, or other weather conditions	4	4.4	0	0.0
Lack of protective device	2	2.2	0	0.0
Malfunction of protective device	7	7.8	0	0.0

Table 10-11—Failure-contributing cause for power and rectifier transformers (1979 survey) *(continued)*

Failure-contributing cause	All power transformers		All rectifier transformers	
	Number of failures[a]	Percentage (%)	Number of failures[b]	Percentage (%)
Loss, deficiency, contamination, or degradation of oil or other cooling medium	9	10.0	3	21.50
Improper operating procedure or testing error	3	3.3	0	0.0
Inadequate maintenance	7	7.8	3	21.5
Others	27	30.0	1	7.1
Exposure to nonelectrical fire or burning	0	0.0	0	0.0
Obstruction of ventilation by foreign object or material	0	0.0	0	0.0
Improper setting of protective device	0	0.0	0	0.0
Inadequate protective device	0	0.0	1	7.1
Total	90	100.0	140	100.0

[a] Failure-contributing cause not specified for 22 failures.
[b] Failure-contributing cause not specified for two failures.

10.3.3.5 Suspected failure responsibility

Table 10-12 summarizes the suspected failure responsibility for power and rectifier transformer failures. The respondents believed that manufacturer defects and inadequate maintenance were responsible for the majority of power transformer failures (i.e., 59.3%). Table 10-12 shows that inadequate operating procedures were a more significant cause of rectifier transformer failures (i.e., 31.2%) than inadequate maintenance.

Table 10-12—Suspected failure responsibility for power and rectifier transformers (1979 survey)

Failure-initiating cause	All power transformers		All rectifier transformers	
	Number of failures[a]	Percentage (%)	Number of failures	Percentage (%)
Manufacturer defective component or improper assembly	32	33.3	5	31.2
Transportation to site, improper handling	1	1.0	0	0.0
Application engineering, improper application	3	3.1	2	12.5
Inadequate installation and testing prior to start-up	6	6.3	0	0.0
Inadequate maintenance	25	26.0	2	12.5
Inadequate operating procedures	4	4.2	5	31.3
Outside agency—Personnel	3	3.1	0	0.0
Outside agency—Others	6	6.3	0	0.0
Others	16	16.7	2	12.5
Total	96	100.00	160	100.00

[a] Suspected failure responsibility not specified for 16 failures.

10.3.3.6 Maintenance cycle and extent of maintenance

The 1973–1974 survey asked the respondent to give an opinion of the maintenance quality as excellent, fair, poor, or none. It is very difficult to be completely objective in responding to this type of question. The 1979 survey, therefore, asked for a brief description of the extent of maintenance performed, the idea being to enable the reader to judge the benefits derived from a particular maintenance procedure. The large percentage of failures that resulted from inadequate maintenance shows the importance of a comprehensive preventive maintenance program and compilation of accurate data on the extent and frequency of the maintenance performed. Unfortunately, the response did not lend itself to reporting in tabular form. Maintenance information continues to be the most difficult to obtain and report for all equipment categories.

10.3.3.7 Type of failure

The 1979 survey limited the choices of failure type to “winding” and “other” as shown in Table 10-13 for power and rectifier transformers. Clearly, the most significant failure type was that occurring in power transformer windings.

Table 10-13—Type of failure for power and rectifier transformers (1979 survey)

Failure-initiating cause	All power transformers		All rectifier transformers	
	Number of failures	Percentage (%)	Number of failures	Percentage (%)
Winding	59	53	8	50
Other	53	47	8	50

10.3.3.8 Failure characteristics

The failure characteristics of power and rectifier transformers are shown in Table 10-14. As would be expected, the survey results show that about 75% of transformer failures resulted in their removal from service by automatic protective devices; however, the percentage requiring manual removal was significant. Increasing use of transformer oil or gas analysis could be a factor here, enabling detection of incipient faults in their early stages, and thus permitting manual removal before a major failure occurs.

Table 10-14—Failure characteristic for power and rectifier transformers (1979 survey)

Failure-initiating cause	All power transformers		All rectifier transformers	
	Number of failures	Percentage (%)	Number of failures	Percentage (%)
Automatic removal by protective device	83	75	11	69
Partial failure, reducing capacity	5	5	0	0
Manual removal	23	20	5	31

10.3.3.9 Voltage rating

The failure rates for liquid-filled power transformers and rectifier transformers classified by their voltage ratings is shown in Table 10-15 and Table 10-16, respectively. An examination of Table 10-15 reveals the failure rate for the 600 V to 15 000 V transformers (i.e., 0.0052 failures per unit year) is less than that for the higher voltage units. The lack of data (i.e., small sample sizes) reported for rectifier transformers makes it impossible to draw any definite conclusions as to the effect of voltage or size on their failure rates.

Table 10-15—Failure characteristic for power and rectifier transformers (1979 survey)

Equipment subclass (kVa)	Voltage (kV)	Number of units	Sample size (unit-years)	Number of failures	Failure rate (failures per unit-year)
Liquid filled 300 to 10 000	0.16 to 15	1626	15 775	82	0.0052
Liquid filled 300 to 10 000	>15	124	1637	18	0.0110
Liquid filled >10 000	>15	52	490	9	0.0184

Table 10-16—Failure rate vs. voltage rating for rectifier transformers (1979 survey)

Equipment subclass	Voltage (kV)	Number of units	Sample size (unit-years)	Number of failures	Failure rate (failures per unit-year)
All liquid filled	0.16 to 15	65	745	15	0.0201

10.3.4 1983 IEEE survey on the reliability of large motors

A decision was made by the IEEE Motor Reliability Working Group to focus on motors that were of a critical nature in industrial and commercial installations, and thus, only motors larger than 200 hp were selected to be included in the survey (see IEEE Committee Report [B11] and Annex H). Another decision was made to limit the survey to only include motors that were 15 years old or less to focus on motors that were similar to those presently being manufactured and used today.

Failure rates are given for induction, synchronous, wound-rotor, and direct-current motors. Pertinent factors that affect the failure rates of these motors are identified. Data is presented on key variables such as downtime per failure, failed component, causes of failure, and the time of failure discovery. The results of this recent survey are compared with four other surveys on the reliability of motors (see Albrecht et al. [B3], IEEE Std 841™-2001 [B16], IEEE Committee Reports [B12], [B14]). Details of the report are shown in Annex H. The results of the survey are summarized in this subclause. The term *large motor* is defined in this subclause to be any motor whose horsepower rating exceeds 200 hp.

10.3.4.1 Overall summary of failure rate for large motors

The 1983 survey included data reported for 360 failures on 1141 motors with a total service of 5085 unit-years. The overall summary of the survey results for induction, synchronous, wound-rotor, and direct-current motors is shown in Table 10-17. Calendar time was used in the calculation of the unit-years of service (rather than the running time) to simplify the data collection procedure.

Table 10-17—Overall summary for large motors above 200 hp[a]

Number of plants in sample size	**Sample size (unit-years)**	**Number of failures reported**	**Equipment subclass**	**Failure rate (failures per unit-year)**	**Average hours down-time per failure**	**Average hours down-time per failure**
75	5085.0	360	All	0.0708	69.3	16.0
			Induction			
33	1080.3	89	0 to 1000 V	0.0824	42.5	15.0
52	2844.4	203	1001 V to 5000 V	0.0714	75.1	12.0
5	78.1	2[b]	5001 V to 15 000 V	[b]	[b]	[b]
			Synchronous			
19	459.3	35	1001 V to 5000 V	0.0762	78.9	16.0
2	29.5	3[b]	5001 V to 15 000 V	[b]	[b]	[b]

Table 10-17—Overall summary for large motors above 200 hp[a] *(continued)*

Number of plants in sample size	Sample size (unit-years)	Number of failures reported	Equipment subclass	Failure rate (failures per unit-year)	Average hours down-time per failure	Average hours down-time per failure
			Wound-rotor			
5	137.0	10	0 to 1000 V	0.0730	b	b
9	251.1	8	1001 V to 5000 V	0.0319	b	b
2	39.0	4[b]	5001 V to 15 000 V	b	b	b
			Direct current			
5	122.7	6[b]	0 to 1000 V	b	b	b
1	30.0	—	1001 V to 5000 V	—	—	—

[a] See O'Donnell [B18].
[b] Small sample size; less than eight failures.

To summarize the important conclusions derived from the 1983 survey on the failure rates of large motors:

a) Induction and synchronous motors had approximately the same failure rate of 0.07 to 0.08 failures per unit-year.

b) Induction motors rated 0 to 1000 V and those rated 1001 V to 5000 V had approximately the same failure rates. The response on motors operating above 5000 V was too small to draw any meaningful conclusions.

c) Wound-rotor motors rated 0 to 1000 V had a failure rate that was about the same as induction motors of the same rating.

d) The sample size for direct current motors was too small to draw any meaningful conclusions.

e) Motors with intermittent duty operation had a failure rate that was about half as great as those with continuous duty.

f) Motors with less than one start per day had approximately the same failure rate as those motors with between one to ten starts per day, which would indicate that up to ten starts per day does not have a major effect on the motor failure rates.

10.3.4.2 Downtime per failure vs. repair/replacement and urgency for repair for large motors

The comparison of the downtime per motor failure data for "repair" vs. "replace with spare" is considered important when deciding whether a spare motor should be purchased when designing a new plant. The downtime per failure survey characteristics for all types of motors grouped together as a category is shown in Table 10-18.

Table 10-18—Downtime per failure vs. repair or replace with spare and urgency for repair—All types of motors above 200 hp[a]

	Number of failures	Average hours (downtime per failure)	Median hours (downtime per failure)
Repair—Normal working hours[b]	87	97.7	24.0
Repair—Round the clock	45	81.4	72.0
Replace with spare[c]	111	18.2	8.0
Low priority	4[d]	370.0[d]	400.0[d]
Not specified	6[d]	288.0[d]	240.0[d]
Total	251	69.3	14.0

[a] See O'Donnell [B18].
[b] 6570 h for one failure omitted.
[c] 960 h for one failure omitted.
[d] Small sample size; less than eight failures.

An examination of Table 10-18 shows the effect on the repair time that the urgency for repair has had. There were 45 cases of motor failures where the repair activities were carried out on a "round-the-clock, all-out" effort. There were four cases of motor failures where "low-priority" urgency resulted in a very long downtime; it is important to exclude these cases when making decisions on the design of industrial and/or commercial power systems. In general, the "average downtime per failure" is about five times larger for repair vs. replace with spare.

10.3.4.3 Failed component—Large motors

The identified motor component that failed is shown in Table 10-19 for induction, synchronous, wound-rotor, direct-current, and "all" motors.

Table 10-19—Failed component—Large motors (above 200 hp) (number of failures)

Failed component[a]	Induction motors	Synchronous motors	Wound-rotor motors	Direct-current motors	Total (all types)
Bearings	152	2	10	2	166
Windings	75	16	6		97
Rotor	8	1	4		13

Table 10-19—Failed component—Large motors (above 200 hp) (number of failures)

Failed component[a]	Induction motors	Synchronous motors	Wound-rotor motors	Direct-current motors	Total (all types)
Shaft or coupling	19	6			19
Brushes or slip ring	—	7	8	2	16
External devices	10	9	1		18
Not specified	40	9		2	51
Total	304	41	29	6	380

[a] Some respondents reported more than one failed component per motor failure.

It can be seen that the two largest categories reported are motor bearing and winding failures with 166 and 97 failures, respectively, out of a total of 380 failures. Bearings and windings represent 44% and 26%, respectively, of the total number of motor failures.

10.3.4.4 Failed component vs. time of discovery—Large motors

Data on the failed component vs. the time the failure was discovered is shown in Table 10-20. It can be seen that 60.5% of the failures found during "maintenance or test" are bearings. Many users consider that it is very important to find as many failures as possible during maintenance or test rather than "normal operation." Bearings and windings represent 36.6% and 33.1%, respectively, of the failures discovered during normal operation.

Table 10-20—Failed component vs. time of discovery (all types of motors above 200 hp) (percentage of failures)

Failed component	Time of discovery		
	Normal operation	Maintenance or test	Other
Bearing	36.6	60.5	50.0
Windings	33.1	8.3	28.6
Rotor	5.1	1.8	0.0
Shaft or coupling	5.8	8.3	14.3
Brushes or slip rings	3.1	7.3	0.0
External devices	5.0	3.7	0.0

Table 10-20—Failed component vs. time of discovery (all types of motors above 200 hp) (percentage of failures) *(continued)*

Failed component	Time of discovery		
	Normal operation	Maintenance or test	Other
Not specified	11.3	10.1	7.1
Total percentage of failures	100.0	100.0	100.0
Total number of failures	257	109.0	14.0

10.3.4.5 Causes of large motor bearing and winding failures

The causes of motor failures categorized according to the failure initiator, the failure contributor, and the failure's underlying cause are shown in Table 10-21 for induction, synchronous, and "all" motors.

Mechanical breakage is the largest failure initiator for induction motors. Normal deterioration from age, high vibration, and poor lubrication are the major failure contributors to induction motor failures. Inadequate maintenance and defective component are the largest underlying causes of induction motor failures.

Electrical fault or malfunction and other insulation breakdown are the major failure initiators for synchronous motors. Normal deterioration from age is the major fault contributor of synchronous motors. Defective component is the largest underlying cause of synchronous motor failures.

Table 10-21 shows a correlation between bearing failures and the causes of failure: 50.3% of bearing failures were initiated by mechanical breakage; 31.3% and 21.8%, respectively, had poor lubrication and high vibration as failure contributors; and 27.6% blamed inadequate maintenance as the underlying cause.

Table 10-21 also shows a correlation between winding failures and the causes of failure: 36.7% of the winding failures had other insulation breakdown as the initiator; 18.5% and 18.5%, respectively, had normal deterioration from age and abnormal moisture as failure contributors; 19.6% had inadequate maintenance and 15.2% had inadequate electrical protection as the underlying cause.

It is of interest to note that inadequate maintenance was the largest underlying cause of both bearing and winding failures. A special study of the 71 failures attributed to inadequate maintenance is shown in Table 10-22. It can be clearly seen that 59.1% of the motor components that failed were bearings, that 52.1% of the failures were initiated by mechanical breakage, and 43.7% of the failures had poor lubrication as a failure contributor.

Table 10-21—Causes of failure vs. motor type and vs. bearing and winding failures—Motors above 200 hp (percentage of failures)

All motor types—failed component		All types of motors (%)	Induction motors (%)	Synchronous motors (%)	Causes of failures
Bearings (%)	Windings (%)				
					Failure initiator
0.0	4.1	1.5	1.4	0.0	Transient overvoltage
12.4	21.4	13.2	14.7	0.0	Overheating
1.9	36.7	12.3	11.9	21.1	Other insulation breakdown
50.3	10.2	33.1	37.4	5.2	Mechanical breakage
3.7	11.2	7.6	5.8	23.7	Electrical fault or malfunction
0.0	2.1	0.9	0.7	2.6	Stalled motor
31.7	14.3	31.4	28.1	47.4	Other
100.0	100.0	100.0	100.0	100.0	Total percentage of failures
161.0	98.0	341.0	278.0	38.0	Total number of failures
					Failure contributor
1.4	6.5	4.2	4.9	2.7	Persistent overheating
0.7	7.6	3.0	3.4	0.0	High ambient temperature
2.7	18.5	5.8	6.7	2.7	Abnormal moisture
0.0	5.4	1.5	1.5	2.7	Abnormal voltage
0.0	1.1	0.6	0.7	0.0	Abnormal frequency
21.8	8.7	15.5	17.6	5.4	High vibration
5.4	6.5	4.2	4.5	2.7	Aggressive chemicals
31.3	5.4	15.2	16.9	8.1	Poor lubrication
0.0	7.6	3.9	2.2	2.7	Poor ventilation or cooling
20.4	18.5	26.4	24.0	51.4	Normal deterioration from age
16.3	14.2	19.7	17.6	21.6	Other
100.0	100.0	100.0	100.0	100.0	Total percentage of failures
147.0	92.0	330.0	267.0	37.0	Total number of failures

Table 10-21—Causes of failure vs. motor type and vs. bearing and winding failures—Motors above 200 hp (percentage of failures) *(continued)*

All motor types—failed component		All types of motors (%)	Induction motors (%)	Synchronous motors (%)	Causes of failures
Bearings (%)	Windings (%)				
					Failure underlying cause
17.8	10.9	20.1	20.3	22.2	Defective component
14.5	10.9	12.9	15.9	0.0	Poor installation/testing
27.6	19.6	21.4	22.8	11.1	Inadequate maintenance
2.0	6.5	3.6	3.3	2.8	Improper operation
0.7	0.0	0.6	0.8	0.0	Improper handling/shipping
7.9	7.6	6.1	6.5	2.8	Inadequate physical protection
2.6	15.2	5.8	5.3	11.1	Inadequate electrical protection
7.2	5.4	6.8	5.7	5.6	Personnel error
2.0	3.3	3.9	2.8	13.9	Outside agency—Not personnel
5.9	4.3	4.9	4.9	0.0	Motor-driven equipment mismatch
11.8	16.3	13.9	11.7	30.5	Other
100.0	100.0	100.0	100.0	100.0	Total percentage of failures
152.0	92.0	309.0	246.0	36.0	Total number of failures

Table 10-22—Failures caused by inadequate maintenance vs. failed component, failure initiator, and failure contributor (all types of motors above hp).[a] (Number of failures in percent)

Percentage (%)	Failed component
59.1	Bearing
25.4	Winding
1.4	Rotor
0.0	Shaft or coupling
8.5	Brushes or slip rings
1.4	External device
4.2	Other
100.0	Total percentage (Number of failures = 71)
Percentage (%)	**Failure initiator**
0.0	Transient over voltage
4.2	Overheating
14.1	Other insulation breakdown
52.1	Mechanical breakage
2.8	Electrical fault or malfunction
0.0	Stalled motor
26.8	Other
100.0	Total percentage (Number of failures = 71)
Percentage (%)	**Failure contributor**
0.0	Persistent overloading
4.2	High ambient temperature
7.0	Abnormal moisture
0.0	Abnormal voltage
0.0	Abnormal frequency
4.2	High vibration
9.9	Aggressive chemical
43.7	Poor lubrication
1.4	Poor ventilation/cooling
18.3	Normal deterioration from age
11.3	Other
100.0	Total percentage (Number of failures = 71)

[a] See O’Donnell [B18].

10.3.4.6 Other significant results

Several additional parameters were reported in O'Donnell [B18] in terms of their effect on the failure rate of motors above 200 hp. These included the effect of horsepower, speed, enclosure, environment, duty cycle, service factor (S. F.), average number of starts per day, grounding practice, maintenance quality, maintenance cycle, type of maintenance performed, and months since last maintenance prior to the failure. Some combinations of these parameters, two at a time, have also been studied and reported (see O'Donnell [B18]).

10.3.4.6.1 Open vs. enclosed motors

The following significant conclusions were reached:

a) Open motors had a higher failure rate than weather-protected or enclosed motors.
b) Indoor motors had a higher failure rate for open motors than for weather-protected or enclosed motors.
c) Outdoor motors had a lower failure rate than indoor motors because most outdoor motors were weather protected or enclosed, and most indoor motors were open.

10.3.4.6.2 Service factor

The 1.15 S. F. induction motors had a higher reported failure rate than 1.0 S. F. induction motors, but the opposite was true for synchronous motors.

10.3.4.6.3 Speed and horsepower

The failure rate for induction motors did not vary significantly among the three speed categories (i.e., 0 to 720 r/min, 721 r/min to 1800 r/min, and 3600 r/min). The highest failure rate was in the middle speed category, while the lowest failure rate was in the 3600 r/min category. The 201 hp to 500 hp induction motors had approximately the same failure rate as 501 hp to 5000 hp induction motors in each of the three speed ranges studied.

Synchronous motors in the speed category 0 to 720 r/min had a higher failure rate than synchronous motors in the 721 r/min to 1800 r/min category. There were no respondents for the 3600 r/min category.

10.3.4.7 Data supports chemical industry motor standard

Reliability data for induction motors from both the 1983 IEEE survey and the 1973–1974 IEEE survey (see Annex A and Annex B) supported the need for several of the features incorporated into IEEE Std 841-2001 [B16]. The IEEE surveys show the need for improved reliability of bearings and windings and, in some cases, the need for better physical protection against aggressive chemicals and moisture. Some of the more significant recommendations for an IEEE 841 motor include:

a) Totally enclosed fan-cooled (TEFC) enclosure

b) Maximum 80 °C rise at 1.0 S. F.
c) Contamination protection for bearings and grease reservoirs
d) Three-year continuous L-10 bearing life
e) Maximum bearing temperature of 45 °C rise (50 °C rise on two-pole motors)
f) Cast-iron frame construction
g) Nonsparking fan
h) Single connection point per phase in terminal box
i) Maximum sound power level of 90 dBA
j) Corrosion-resistant paint, internal joints and surfaces, and hardware

IEEE Std 841-2001 [B16] was tailored for the petroleum/chemical industry; however, it can be beneficial for other industries with similar requirements.

10.3.4.8 Comparison of 1983 motor survey with other motor surveys

One of the primary purposes of comparing the results of 1983 motor survey with previous surveys and other surveys (see Albrecht et al. [B2], [B3], and the "Summary of Replies to the 1982 Technical Questionnaire" [B29]) is to attempt to identify trends in the failure characteristics of motors (i.e., changing failure rates with time, varying causes of motor failures, assessing the impact of maintenance practices).

10.3.4.8.1 1983 EPRI and 1983–1985 IEEE surveys

The size and scope of the IEEE Working Group and EPRI motor surveys is shown in Table 10-23. The motor failure rate of 0.035 failures per unit-year in the EPRI-sponsored study of the electric utility industry is about half the IEEE failure rate of 0.0708 failures per year.

The percentage of motor failures classified by component in the two surveys is shown in Table 10-24. Similar results were obtained in these two studies on the failed component, with bearing, winding, and rotor-related percentages that were each about the same.

Table 10-23—Size and scope comparison of IEEE 1983–1985 motor survey[a] and EPRI-sponsored motor survey in electric utility power plants

Parameter	IEEE Working Group	EPRI Phase I
Horsepower	> 200	100 and up
Number of companies/utilities	33	56
Number of plants or units	75	132
Number of motors	114 100	47 970
Total population (unit-years)	508 500	24 914 100
Total failures (Tf)	3600	871 100
Failure rate (all motors)	0.07080	0.03500[b]

[a] See O'Donnell [B18].
[b] To first failure.

Table 10-24—Failure by component comparison of the IEEE 1983–1985 motor survey and EPRI-sponsored survey

IEEE Working Group	EPRI Phase I
44% bearings	41% bearing related
26% windings	37% stator related
8% rotor/shafts/couplings	10% rotor related

Table 10-25 shows some differences between the two studies on the causes of failures. The IEEE survey found "inadequate maintenance," "poor installation/testing," and "misapplication" to be a significant larger percentage of the causes of motor failures; while the EPRI study attributed a larger percentage to the manufacturer. In addition, the EPRI study had a much larger percentage of failures attributed to "other or not specified." Additional results from the EPRI-sponsored study were given in a later paper (see Albrecht et al. [B3]).

Table 10-25—Cause of failure comparison—IEEE 1983–1985 motor survey and EPRI-sponsored motor survey

Failure cause	EPRI Phase I		IEEE Working Group		Failure cause
	Number	Percent	Number	Percent	
Manufacturer design workmanship	401	32.8	62	17.2	Defective component
Misoperation	124	10.2	32	8.9	Improper operation/ personnel error
Misapplication	83	6.8	52	14.5	Misapplication; motor-driven equipment mismatch; inadequate electrical protection; inadequate physical protection.
—			66	18.3	Inadequate maintenance
—			40	11.1	Poor installation/testing
—			12	3.3	Outside agency other than personnel
—			2	0.6	Improper handling/shipping
Other or not specified	613	50.2	94	26.1	Other or not specified
Total	1221	100.0	360	100.0	

10.3.4.8.2 1982 Doble data and 1983–1985 IEEE surveys

A 1982 Doble survey (see "Summary of Replies to the Technical Questionnaire" [B29]) in the electric utility industry (for motors 1000 hp and up and not over 15 years of age) reported 68 insulation-related failures in 2078 unit-years of service during the year 1981. This gives an insulation-related failure rate of 0.033 failures per unit-year. This can be compared with a winding failure rate of 26% times 0.0708, which equals 0.018 failures per unit-year that can be calculated from the l983–1985 IEEE survey of motors above 200 hp and not older than 15 years is shown in Table 10-23 and Table 10-24.

10.3.4.8.3 IEEE Surveys 1973–1974 and 1983–1985

Table 10-26 shows the results from the 1973–1974 IEEE motor reliability survey of industrial plants (see IEEE Committee Report [B12]). This survey covered motors 50 hp and larger, and had no limit on the age of the motor. Those results can be compared to Table 10-17 for the 1983–1985 IEEE survey of motors above 200 hp and not older than 15 years. The 1983–1985 failure rates of induction motors and synchronous motors were about double those from the 1973–1974 survey for motors 601 V to 15 000 V.

Table 10-26—1973–1974 IEEE overall summary for motors 50 hp and larger

Number of plants in sample size	Sample size (unit-years)	Number of failures reported	Equipment subclass	Failure rate (failures per unit-year)	Average hours down-time per failure	Median hours down-time per failure
—	42 463	561	All	0.0132	111.6	—
			Induction			
17	19 610	213	0 to 600 V	0.0109	114.0	18.3
17	4229	172	5001 V to 15 000 V	0.0404	76.0	153.0
			Synchronous			
2	13 790	10	1001 V to 5000 V	0.0007	35.3	35.3
11	4276	136	5001 V to 15 000 V	0.0318	175.0	153.0
6	558	310	Direct current	0.0556	37.5	16.2
—	42 463	561	All	0.0132	111.6	—

10.3.4.8.4 AIEE 1962 and 1983–1985 IEEE surveys

Table 10-27 shows the results from the 1962 AIEE motor reliability survey of industrial plants. This survey covered motors 250 hp and larger and had no limit on the age of the motor. The failure rates for both induction motors and synchronous motors from the 1962 AIEE survey are within 30% of those shown in Table 10-17 for the 1983–1985 IEEE survey of motors above 200 hp and not older than 15 years. The two surveys conducted 21 years apart show remarkably similar results.

Table 10-27—1962 AIEE overall summary for motors 250 hp and larger, U.S. and Canada

Number of plants in sample size	Sample size (unit-years)	Number of failures reported	Equipment subclass	Failure rate (failures per unit-year)	Average hours down-time per failure	Median hours down-time per failure
46	1420	140	Induction	0.0986	78.0	70.0
53	600	31	Synchronous	0.0650	149.0	68.0

10.3.5 1994 IEEE-PES survey of overhead transmission lines

The IEEE Power Engineering Society conducted an extensive survey of the outages of overhead transmission lines 230 kV and above in the U.S. and Canada (see Adler et al. [B1]). This is included as Annex O and covers 230 kV, 345 kV, 500 kV, and 765 kV and includes both permanent and momentary outages. Line-caused outages have been separated out from terminal-caused outages. Data are given on the type of fault that caused the outage. Faults can result in voltage sags at the entrance to industrial and commercial installations.

10.4 Part 3: Equipment reliability surveys conducted prior to 1976

10.4.1 Introduction

From 1973 to 1975, the Power Systems Reliability Subcommittee of the IEEE Industrial Power Systems Department conducted and published surveys of electrical equipment reliability in industrial plants (see IEEE Committee Reports [B10], [B12]). Those reliability surveys of electrical equipment and electric utility power supplies were extensive, and summaries of the following pertinent reliability data are given in this subclause:

a) Failure rate and outage duration time for electrical equipment and electric utility power supplies

b) Failure characteristic or failure modes of electrical equipment; that is, the effect of the failure on the system

c) Causes and types of failures of electrical equipment

d) Failure repair method and failure repair urgency

e) Method of service restoration after a failure

f) Loss of motor load vs. time of power outage

In addition, reference is made to summaries of pertinent reliability data and information that are contained in other chapters, including the maximum length of time of an interruption of electrical service that will not stop plant production, plant restart time after service is restored following a failure that caused a complete plant shutdown, and the cost of power interruptions to industrial plants and commercial buildings. In addition an example shows that the two power sources in a double-circuit utility supply may not be completely independent, the equipment failure rate multipliers vs. maintenance quality, and the percentage of failures caused by inadequate maintenance vs. month since maintained.

All of the reliability data summarized in the previous 12 items was taken from the IEEE surveys of industrial plants (see Albrecht et al. [B3] and the "Report on Equipment Availability for a 10 Year Period" [B22]) and commercial buildings (see O'Donnell [B18]). The detailed reports are given in Annex A, Annex B, Annex C, and Annex D. A later survey (IEEE Committee Report [B13]) of the reliability of switchgear bus is included in Annex E. More recent surveys on transformers, large motors, and cable, terminations, and splices are included in Annex G, Annex H, and Annex I, respectively. Recent surveys on circuit breakers are shown in Annex J and Annex K. A 1989 survey on diesel and gas turbine generating units is included in Annex L.

10.4.2 Reliability of electrical equipment (1974 survey)

The term *electrical equipment* in this subclause includes all the electrical equipment listed in Table 10-28.

Table 10-28—In-plant electrical equipment list

Electrical equipment	
Circuit breakers (some)	Open wire
Motor starters	Cable
Disconnect switches—enclosed	Cable joints (some)
Bus duct	Cable terminations

In compiling the data for the 1974 survey, a failure was defined as any trouble with a power system component that causes any of the following effects:

a) Partial or complete plant shutdown, or below-standard plant operation

b) Unacceptable performance of user's equipment

c) Operation of the electrical protective relaying or emergency operation of the plant electric system

d) De-energization of any electric circuit or equipment

A failure on a public utility supply system may cause the user to have either of the following:

1) A power interruption or loss of service
2) A deviation from normal voltage or frequency outside the normal utility profile

A failure on an in-plant component causes a forced outage on the component, that is, the component is unable to perform its intended function until it is repaired or replaced. The terms *failure* and *forced outage* are often used synonymously.

All of the electrical equipment categories listed in this subclause have eight or more failures. This is considered an adequate sample size (see Patton [B21]) in order to have a reasonable chance of determining a failure rate within a factor of 2. Failure rate and average downtime per failure data for an additional six categories of equipment are contained in IEEE Committee Report [B12] (see Annex A).

The additional categories of equipment that have between four and seven failures and thus might be considered by some as too small a sample size include the following:

- Circuit breakers used as motor starters
- Disconnect switches—open
- Cable joints, 601 V to 15 000 V, aboveground and aerial
- Cable joints, 601 V to 15 000 V, thermosetting
- Fuses
- Protective relays

10.4.2.1 Failure modes of circuit breakers

The failure modes of "metal-clad drawout" and "fixed-type" circuit breakers are shown in Table 10-29. Of primary concern to industrial plants is the large percentage of circuit breaker failures (i.e., 42%) that "opened when it should not." This type of circuit breaker failure can significantly affect plant processes and may result in a total plant shutdown. Also, a large percentage (i.e., 32%) of the circuit breakers "failed while in service (not while opening or closing)." Annex J, Annex K, and "Report on Power Circuit Troubles—1975" [B27] contain additional detailed information on circuit breaker reliability.

10.4.2.1.1 Trip units on low-voltage breakers

Most modern low-voltage power circuit breakers are purchased with a solid-state trip unit rather than an electromechanical trip unit. Many older low-voltage breakers have been retrofitted with a solid-state trip that replaced an electromechanical trip unit. A comparison has been made of the reliability of these two types of trip units. This included both the "trip unit failed to operate" and the "trip unit out of specification."

A 1996 IEEE Survey was made of low-voltage breaker operation as found during maintenance (see O'Donnell [B19]). This is included as Annex P. A summary of the most important results is given in Table 10-30. Electromechanical trip units had an unacceptable operation about twice as often as solid-state units.

Table 10-29—Failure modes of circuit breakers[a] (1974 survey) (Percentage of total failure in each failure mode)

All circuit breakers (%)	Metal-clad drawout			Failed type[b]		Failure characteristics
	All (%)	0 to 600 V 601 V to 15 000 V (%)	All sizes (%)	0 to 600 V All sizes (%)	All (%)	
5	5	2	7	8	6	Failed to close when it should
9	120	210	0	0	2	Failed while opening
420	580	490	710	5	4	Opened when it should not
7	6	4	9	5	4	Damaged while successfully opening
2	1	0	0	0	4	Damaged while closing
320	160	240	100	770	7 30	Failed while in service (not while opening or closing)
1	0	0	0	0	2	Failed during testing or maintenance
1	2	0	3	0	0	Damage discovered during testing or maintenance
1	0	0	0	5	5	Other
100	100	100	100	100	100	Total percentage
166	117	53	59	39	48	Number of failures in total percentage
8	7	0	7	1	1	Number not reported
173	124	53	66	40	49	Total failures

[a] Annex K contains some limited data from a later IEEE survey. Annex J contains data for circuit breakers above 63 kV from a CIGRE 13-06 worldwide survey with a very large population.

[b] Includes molded case.

Table 10-30—Survey of low-voltage power breaker operation as found during maintenance tests—electromechanical vs. solid-state trip type unit; new solid-state units vs. used (older) solid-state units (Percentage of total failure in each failure mode)

	Trip unit type			
	Electromechanical		Solid-state	
	Number of tests	Percentage (%)	Number of tests	Percentage (%)
Unacceptable operation				
a) Trip unit failed to operate	81	7.7	28	3.0
b) Trip unit out of specification	60	5.7	24	2.6
c) Mechanical operations (springs, arms/levers, hardened lubricant)	26	2.5	19	2.0
d) Power contacts (alignment, incorrect pressure, pitted)	25	2.4	19	2.0
e) Arc chutes (clean, replace/repair, chipped)	6	0.6	6	0.7
f) Auxiliary contacts	4	0.4		
Total unacceptable	204	19.4	100	10.7
Acceptable operation	850	80.6	835	89.3
Total number of tests	1054	100.0	935	100.0

10.4.2.2 Failure characteristics of other electrical equipment

The failure characteristics of electrical equipment (excluding transformers and circuit breakers) are shown in Table 10-31. The dominant failure characteristic for this equipment is that it “failed in service.” A large percentage of the damage to motor starters (i.e., 36%), disconnect switches (i.e., 18%), and cable terminations (i.e., 12%) was discovered during testing or maintenance; however, the remaining electrical equipment did not significantly exhibit this failure characteristic.

10.4.2.3 Causes and types of failures of electrical equipment

The following data is presented in Table 10-32 and Table 10-33:

a) Failures, damaged part
b) Failure type
c) Suspected failure responsibility
d) Failure-initiating cause

e) Failure-contributing cause

The data presented in Table 10-33 indicate that the respondents suspected "inadequate maintenance" and "manufacturer—defective-component" were responsible for a significant percentage of the failures for several categories of electrical equipment.

Table 10-31—Failure characteristics of other electrical equipment

Motor starters (%)	Dis-connect switches (%)	Bus duct (%)	Open wire (%)	Cable (%)	Cable joint (%)	Cable ter-mina-tions (%)	Failure characteristics
37	72	90	68	92	96	80	Failed in service
6	3	5	2	2	4	2	Failed during testing or maintenance
36	18	0	1	2	0	12	Damage discovered during testing or maintenance
20	6	5	6	3	0	6	Partial failure
2	1	0	23	1	0	0	Other

10.4.2.4 Failure repair method and failure repair urgency

The "failure repair method" and the "failure repair urgency" had a significant effect on the "average downtime per failure." Table 10-34 shows the percentages of these two parameters for eight classes of electrical equipment. A special study on this subject is reported in Tables 50, 51, 55, and 56 of Patton [B21] (see also Annex B) for circuit breakers and cables (see footnote d of Table 10-2 of this chapter).

10.4.2.5 Reliability of electric utility power supplies to industrial plants

The "failure rate" and the "average downtime per failure" of electric utility supplies to industrial plants are given in Table 10-35. Additional details are given in Annex D of "Report on Equipment Availability for 10 Year Period 1965–74" [B22]). A total of 87 plants participated in the IEEE survey covering the period from 1 January 1968 through October 1974.

Table 10-32—Failure, damaged part, and failure type (1974 survey)

Circuit breakers (%)	Motor starters (%)	Disconnect switches (%)	Bus duct (%)	Open wire (%)	Cable (%)	Cable joints (%)	Cable terminations (%)	Failure, damaged part
0	5	0	15	0	5	0	0	(1) Insulation—winding
2	0	1	10	1	0	0	12	(2) Insulation—bushing
19	10	14	65	6	83	91	74	(3) Insulation—other
1	0	0	0	0	3	0	0	(4) Mechanical—bearings
11	16	9	0	0	0	0	0	(5) Mechanical—other moving parts
6	2	30	0	4	1	0	4	(6) Mechanical—other
6	13	8	0	3	1	0	0	(7) Other electric—auxiliary device
28	2	1	0	3	1	0	0	(8) Other electric—protective device
1	0	0	0	0	0	0	0	(9) Tap changer—no load type
0	0	0	0	0	0	0	0	(10) Tap changer—load type
26	52	37	10	83	6	9	10	(99) Other
								Failure type
33	14	15	70	34	73	70	55	(1) Flashover or arcing involving ground
10	20	4	30	23	1	9	4	(2) All other flashover or arcing
19	55	47	0	25	7	20	37	(3) Other electric defects
11	11	14	0	6	5	0	4	(4) Mechanical defect
27	0	20	0	12	14	0	0	(99) Other

Table 10-33—Suspected failure responsibility, failure-initiating cause, and failure-contributing cause (1974 survey)

Circuit breakers (%)	Motor starters (%)	Dis-connect switches (%)	Bus duct (%)	Open wire (%)	Cable (%)	Cable joints (%)	Cable termina-tions (%)	Suspected failure responsibility
23	18	29	26	0	16	0	0	(1) Manufacturer—defective component
0	0	0	0	0	0	0	0	(2) Transportation to site— defective handling
4	51	6	16	2	8	0	18	(3) Application engineering— improper application
3	0	4	5	9	14	50	38	(4) Inadequate installation and testing prior to start-up
23	8	13	16	30	10	18	32	(5) Inadequate maintenance
6	3	39	0	2	3	0	0	(6) Inadequate operating procedures
5	0	1	5	5	4	5	0	(7) Outside agency—personnel
1	0	0	0	21	6	2	8	(8) Outside agency—other
35	20	8	32	31	39	25	14	(9) Other

Table 10-33—Suspected failure responsibility, failure-initiating cause, and failure-contributing cause (1974 survey) *(continued)*

Circuit breakers (%)	Motor starters (%)	Dis-connect switches (%)	Bus duct (%)	Open wire (%)	Cable (%)	Cable joints (%)	Cable termina-tions (%)	Suspected failure responsibility
								Failure-initiating cause
4	0	8	6	0	0	0	0	(1) Persistent overloading
1	0	3	0	0	0	2	0	(2) Above-normal temperature
0	0	1	0	0	0	0	0	(3) Below-normal temperature
2	0	0	0	28	14	13	10	(4) Exposure to aggressive chemicals or solvents
3	0	4	17	1	8	22	12	(5) Exposure to abnormal moisture or water
0	0	0	0	3	2	0	0	(6) Exposure to nonelectrical fire or burning
0	0	0	0	0	1	0	0	(8) Obstruction of ventilation by objects or material
17	40	5	49	3	30	29	24	(9) Normal deterioration from age
1 2	0 0	0 0	11 0	30 1	16 0	2	16	(10) Severe wind, rain, snow, sleet, or other weather conditions
1	2	0	0	0	0	0	0	(11) Protective relay improperly set
0	0	0	0	0	0	0	0	(12) Loss or deficiency of lubricant
10	3	0	6	2	3	0	0	(13) Loss of deficiency of oil or cooling medium
3	1	26	0	2	1	0	8	(14) Misoperation or testing error
						0	0	(15) Exposure to dust or other contaminants
56	54	54	11	30	24	32	30	(99) Other

Table 10-34—Failure repair method and failure repair urgency (1974 survey)

Circuit breakers (%)	Motor starters (%)	Dis-connect switches (%)	Bus duct (%)	Open wire (%)	Cable (%)	Cable joints (%)	Cable termi-nations (%)	Failure repair method
51	33	30	66	70	47	87	60	(1) Repair of failed component in place or sent out for repair
49	67	70	35	9	53	13	34	(2) Repair by replacement of failed component with spare
0	0	0	0	21	0	0	6	(99) Other
								Failure repair urgency
73	66	20	80	55	66	56	53	(1) Requiring round- the-clock all-out efforts
22	34	80	15	26	28	22	31	(2) Requiring repair work only during regular workday, perhaps with overtime
5	0	0	5	0	6	22	16	(3) Requiring repair work on a non-priority basis
0	0	0	0	19	0	0	0	(99) Other

Table 10-35—IEEE survey of reliability of electric utility supplies to industrial plants (IEEE Committee Report (1975 survey) (See Tables II, III, IV, and V in Annex D for additional details)

	Failures per unit-year[a]			Average duration (minutes per failure)[a]		
	$\lambda\Sigma$	λP	λ	rS	rR	r
Single-circuit utility supplies						
Voltage level						
0 ≥15 kV	0.905	2.715	3.621	3.5	165	125
15 kV < V ≤ 35 kV		1.657	1.657		57	57
> 35 kV	0.527	0.843	1.370		59	37
All	0.556	1.400	1.956	2.3	110	79
Multiple-circuit utility supplies (all voltage levels)						
Switching scheme						
All breakers closed	0.255	0.057	0.312	8.5	130	31
Manual throw-over	0.732	0.118[b]	0.850	8.1	84[b]	19
Automatic throw-over	1.025	0.171	1.196	0.6	96	14
All	0.453	0.085	0.538	5.2	110	22
Multiple-circuit utility supplies (all switching schemes)						
Voltage level						
0 ≥15 kV	0.640	0.148	0.788	4.7	149	32
15 kV < V ≤ 35 kV	0.500	0.064[b]	0.564	4.0	115[b]	17
> 35 kV	0.357	0.067	0.424	6.1	184	34
Multiple-circuit utility supplies (all circuit breakers closed)						
Voltage level						
0 ≥15 kV	0.175	0.088[b]	0.263	0.7	335[b]	112
15 kV < V ≤ 35 kV	0.342	0.019[b]	0.361	7.0	120[b]	13
> 35 kV	0.250	0.061	0.311	11.0	203	49

[a] Failure rates λS and λR and average durations rS and rR are, respectively, rates and durations of failures terminated by switching and by repair or replacement. Unsubscripted rates and durations are overall values.

[b] Small sample size; less than eight failures.

The survey results shown in Table 10-35 have distinguished between power failures that were terminated by a switching operation vs. those requiring repair or replacement of equipment. The latter have a much longer outage duration time. Some of the conclusions that can be drawn from the IEEE data are:

a) The failure rate for single-circuit supplies is about 6 times that of multiple-circuit supplies that operate with all circuit breakers closed, and the average duration of each outage is about 2.5 times as long.

b) Failure rates for multiple-circuit supplies that operate with either a manual or an automatic throw-over scheme are comparable to those for single-circuit supplies, but throw-over schemes have a smaller average failure duration than single-circuit supplies.

c) Failure rates are highest for utility supply circuits operated at distribution voltages and lowest for circuits operated at transmission voltages (greater than 35 kV).

It is important to note that the data in Table 10-34 shows that the two power sources of a double-circuit utility supply are not completely independent. This is analyzed in an example in 3.3.3, where (for the one case analyzed) the actual failure rate of a double-circuit utility supply is more than 200 times larger than the calculated value for two completely independent utility power sources.

Utility supply failure rates vary widely in various locations. One of the significant factors in this difference is believed to be different exposures to lightning storms. Thus, average values for the utility supply failure rate may not be appropriate for use at any one location. Local values should be obtained, if possible, from the utility involved, and these values should be used in reliability and availability studies.

An earlier IEEE reliability survey of electric power supplies to industrial plants was published in 1973 and is reported in Table 3 of Albrecht et al. [B3] (see also Annex A). The earlier survey had a smaller database and is not believed to be as accurate as the one summarized in Table 10-34. The earlier survey of electric utility power supplies had lower failure rates.

10.4.2.6 Method of electrical service restoration to plant

The 1973–1975 IEEE data on “method of electrical service restoration to plant” is shown in Table 10-36. A percentage breakdown of the method of restoration to plant is ranked as follows:

a) Replacement of failed component with spare: 22%
b) Repair of failed component: 22%
c) Other: 22%
d) Utility service restored: 12%
e) Secondary selection—manual: 11%
f) Primary selection—manual: 7%
g) Primary selection—automatic: 2%
h) Secondary selection—automatic: 2%
i) Network protector operation—automatic: 0%

The most common methods of service restoration to a plant are replacement of a failed component with a spare or the repair of the failed component. The primary selection or secondary selection is used only 22% of the time. This would indicate that most power distribution systems in this IEEE survey were radial.

Table 10-36—Method of service restoration (1974 survey)

Total (%)	Electric utilities power supplies (%)	Transformers (%)	Circuit breakers (%)	Motor starters (%)	Motors (%)	Generators (%)	Disconnect switches (%)	Switchgear bus—insulated	Switchgear bus—bare (%)	Bus duct (%)	Open wire (%)	Cable (%)	Cable joints (%)	Cable terminations (%)	Method of service restoration
7	1	3	6	0	5	20	0	58	25	20	13	14	28	19	(1) Primary selective—manual
2	8	0	1	0	0	0	0	0	5	0	4	5	8	0	(2) Primary selective—automatic
11	1	25	6	0	14	33	0	17	10	10	2	20	32	23	(3) Secondary selective—manual
2	1	3	8	0	0	0	0	0	0	0	1	0	8	4	(4) Secondary selective—automatic
0+	0	0	0	0	0	0	0	0	5	0	0	0	0	0	(5) Network protector operation—automatic
22	5	25	11	12	30	20	3	17	20	35	31	42	24	27	(6) Repair of failed component
22	2	39	38	10	29	14	77	0	10	35	6	2	0	12	(7) Replacement of failed component

Table 10-36—Method of service restoration (1974 survey) *(continued)*

Total (%)	Electric utilities power supplies (%)	Transformers (%)	Circuit breakers (%)	Motor starters (%)	Motors (%)	Generators (%)	Disconnect switches (%)	Switchgear bus—insulated	Switchgear bus—bare (%)	Bus duct (%)	Open wire (%)	Cable (%)	Cable joints (%)	Cable terminations (%)	Method of service restoration
12	81	0	1	0	0	13	0	0	0	0	1	1	0	0	(8) Utility service restored
22	1	5	29	78	22	0	20	8	25	0	42	16	0	15	(9) Other
100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	Total percentage
1204	171	75	160	68	318	15	69	12	20	20	103	122	25	25	Total number reported

10.4.2.7 Equipment failure rate multiplier vs. maintenance quality

The relationship between maintenance practice and equipment failures is discussed in detail in Chapter 5. Equipment failure rate multipliers vs. maintenance quality are given in Chapter 5 for transformers, circuit breakers, and motors. These multipliers were determined in a special study (Part 6 of Patton [B21]) (see also Annex B). The failure rate of motors is very sensitive to the quality of maintenance.

The percentage of failures due to “inadequate maintenance” vs. the “time since maintained” is given in Chapter 5 for circuit breakers, motors, open wire, transformers, and all electrical equipment classes combined. A high percentage of electrical equipment failures were blamed on inadequate maintenance if there had been no maintenance for more than 2 years prior to the failure.

10.4.2.8 Reliability improvement of electrical equipment in industrial plants between 1962 and 1973

The failure rates for electrical equipment (except for motor starters) in industrial plants appeared to have improved considerably during the 11-year interval between the 1962 AIEE reliability survey (see Dickinson [B5]) and the 1973-74 IEEE reliability survey (see IEEE Committee Report [B12]). Table 10-37 shows how much the failure rates had improved for several equipment categories. These data are calculated from a 1974 report (Albrecht et al. [B2]). In 1962 circuit breakers had failure rates that were 2.5 to 6.0 times higher than those reported in 1973. The largest improvements in equipment failure rates have occurred on cables and circuit breakers. The authors discussed some of the reasons for the failure rate improvements during the 11-year interval. It would appear that manufacturers, application engineering, installation engineering, and maintenance personnel have all contributed to the overall reliability improvement.

The authors also make a comparison between the surveys of the “actual downtime per failure” for all the equipment categories shown in the table in IEEE Committee Report [B12]. However, in general the actual downtime per failure was larger in 1973 than in 1962.

Table 10-37—Failure rate improvement factor of electrical equipment in industrial plants during the 11-year interval between the 1962 AIEE survey and the 1973 IEEE survey

Equipment category	Failure rate ratio AIEE (1962) / IEEE (1973)
Cable	
Nonleaded in underground conduit	9.7
Nonleaded, aerial	5.8
Lead-covered in underground conduit	3.4
Nonleaded in aboveground conduit	1.6
Cable joints and terminations	
Nonleaded	5.3
Leaded	2.0
Circuit breakers	
Metal-clad drawout, 0 to 600 V	6.0
Metal-clad drawout, above 600 V	2.9
Fixed 2.4 kV to 15 kV	2.5
Disconnect switches	
Open, above 600 V	3.4
Enclosed, above 600 V	1.6
Open wire	3.4
Transformers	
Below 15 kV, 0 to 500 kVA[a]	2.0
Below 15 kV, above 500 kVA	2.0
Above 15 kV	1.6
Motor starters, contactor type	
0 to 600 V	1.3
Above 600 V	1.3

[a] 300 kVA to750 kVA for 1973.

10.4.2.9 Loss of motor load vs. time of power outage

A special study was reported in Table 47 of IEEE Committee Report [B12] (see Annex B) on loss of motor load vs. duration of power outages. When the duration of power outages is longer than 10 cycles, most plants lose motor load. However, when the duration of power outages is between 1 and 10 cycles, only about one-third of the plants lose their motor load.

Test results of the effect of fast bus transfers on load continuity are reported in Averill [B4]. This includes 4 kV induction and synchronous motors with the following type of loads:

a) Forced draft fan

b) Circulating water pump

c) Boiler feed booster pump

d) Condensate pump

e) Gas recirculation fan

A list of prior papers on the effect of fast bus transfer on motors is also contained in Albrecht et al. [B3].

10.4.2.10 Critical service loss duration time

What is the maximum length of time that an interruption of electrical service will not stop plant production? The median value for all plants is 10.0 s. See Table 7-2 for a summary of the IEEE survey of industrial plants.

What is the maximum length of time before an interruption to electrical service is considered critical in commercial buildings? The median value of all commercial buildings is between 5 min and 30 min. See Table 7-2 for a summary of the IEEE survey of commercial buildings.

10.4.2.11 Plant restart time

What is the plant restart time after service is restored following a failure that has caused a complete plant shutdown? The median value for all plants is 4.0 h. See Table 7-2 for a summary of the IEEE survey of industrial plants.

10.4.2.12 Other sources of reliability data

The reliability data from industrial plants that are summarized are based upon IEEE Committee Report [B12], which was published during 1973–1975. Dickinson's report [B5] is an earlier reliability survey of industrial plants that was published in 1962. Portions of that data are tabulated in Table 7-1.

Many sources of reliability data on similar types of electrical equipment exist in the electric utility industry. The Edison Electric Institute (EEI) has collected and published reliability data on power transformers, power circuit breakers, metal-clad switchgear, motors, excitation systems, and generators (see EEI Publications [B22], [B23], [B24], [B25], [B26], [B27], [B28]). Most EEI reliability activities do not collect outage duration time data. The North American Electric Reliability Council (NERC) collects and publishes reliability and availability data on generation prime mover equipment.

Failure rate data and outage duration time data for power transformers, power circuit breakers, and buses are given in Patton [B21]. These data have come from electric utility power systems.

Very little other published data is available on failure modes of power circuit breakers and on the probability of a circuit breaker not operating when called upon to do so. An extensive worldwide reliability survey of the major failure modes of power circuit breakers above 63 kV on utility power systems has been made by the CIGRE 13-06 Working Group, as shown in Annex J. Failure rate data and failure per operating cycle data have been determined for each of the major failure modes. Outage duration time data has also been collected. In addition, data has been collected on the costs of scheduled preventive maintenance; this includes the man-hours per circuit breaker per year and the cost of spare parts consumed per circuit breaker per year.

IEEE Std 500-1984 [B15] is a reliability data manual for use in the design of nuclear power generating stations. The equipment failure rates therein cover such equipment as annunciator modules, batteries and chargers, blowers, circuit breakers, switches, relays, motors and generators, heaters, transformers, valve operators and actuators, instruments, controls, sensors, cables, raceways, cable joints, and terminations. No information is included on equipment outage duration times.

The Institute of Nuclear Power Operations (INPO) organization operates the Nuclear Plant Reliability Data System (NPRDS), which collects failure data on electrical components in the safety systems of nuclear power plants. Outage duration time data is collected on each failure. The NPRDS database contains more details than IEEE Std 500-1984, but INPO has followed a policy of not publishing its data.

Very extensive reliability data have been collected for electrical and mechanical equipment used on “offshore platforms” in the North Sea and the Adriatic Sea (see OREDA-92 [B20]. This includes generators, transformers, inverters, rectifiers, circuit breakers, protection equipment, batteries, battery chargers, valves, pumps, heat exchangers, compressors, gas turbines, sensors, cranes, etc. Data have been published on failure rates, number of demands, failures per demand, repair time, and repair man-hours. Ten oil companies have participated in this data collection over a period of 9 years.

10.5 Bibliography

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[2] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, P.O. Box 1331, Piscataway, NJ 08855-1331, USA (http://standards.ieee.org/).

[3] The IEEE standards or products referred to in this clause are trademarks of the Institute of Electrical and Electronics Engineers, Inc

[4] Available from Det Norske Veritas Industri Norge AS, DNV Technica, P.O. Box 300, N-1322 Novik.

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Chapter 11
Data collection

11.1 Data collection[a]

Five categories of information contain the necessary data for reliability modeling: *site identification, site one-line drawings, nameplate information, critical equipment designation and sparing,* and *maintenance data.* When combined this information gives the analyst all the necessary data to populate a reliability model. Data collection for facilities is not intended to be done in a single setting nor in a single month. This is an ongoing activity that should be completed in as timely a manner as possible without impacting the readiness of the facility. Once completed, updates to the information are only necessary as maintenance is performed on the equipment.

11.2 Facility identification data

Facility identification data provides basic information about the equipment and the particular facility. Facility identification data consists of the following:

a) Date of the survey—Establishes the site configuration baseline date.
b) Facility name/ID number/location—Identifies the facility.
c) Equipment facility name/ID—Identifies the equipment with a site specific ID number, name, or location.
d) In-service date—Provides the date the equipment was installed, which gives the analyst a starting point to calculate time to failure metrics.
e) Parent system—Allows the equipment to be assigned to the proper site subsystem.

11.3 Facility one-line drawings

One-line drawings are used to develop the reliability block diagrams (RBDs) and can indicate reliability borders for the electrical distribution, pneumatic, or pluming systems. The one-line also indicates critical and redundant equipment, systems, and circuits. These drawing may also provide length of wires and pipe, which are needed for the reliability models.

11.4 Nameplate information

Nameplate data identifies the equipment and its specifications that allow the analyst to obtain time to failure data from the equipment manufacturer or to utilize commercial or military failure databases such as the IEEE or DoD's Reliability Analysis Center. Nameplate data consists of the following:

a) Equipment manufacturer
b) Equipment model
c) Equipment type
d) Equipment ratings

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[a] Chapter 11 uses information from Department of the Army, TM 5-698-6, *Reliability Data Collection Handbook for C4ISR Facilities,* 27 October 2006.

11.5 Critical equipment designation and sparing

Critical equipment designation and sparing data identifies equipment that is critical to the mission of the particular facilities. Critical equipment must be highly reliable; generally more reliable than is practical in a single piece of equipment. In general, this equipment has an automatically switched spare or a quickly replaceable spare on-site. Critical equipment designation and sparing data consists of the following:

a) Critical equipment designation—Identifies mission critical equipment.
b) Redundant equipment—Identifies the presence or lack of redundant equipment for critical equipment.
c) Spares—Identifies on-site critical equipment spares.

11.6 Maintenance data

Maintenance data provides the reliability analyst with time to failure data as well as insight into the level of periodic maintenance performed on a piece of equipment. Time to failure data provides data for calculation of time to failure metrics while periodic maintenance data allows a validation of manufacturer supplied failure data. This data contains both scheduled and unscheduled maintenance actions. Scheduled maintenance lists periodic maintenance while unscheduled maintenance lists equipment failures and repairs. Maintenance data consists of the following:

a) Handwritten log books or records
b) Computerized maintenance records

11.7 Data forms

The manual data forms in Annex 11A have been developed for the facility engineer’s use. These forms contain the necessary data to be collected on the equipment. In order to keep the forms to a minimum, there is a single form for each class of equipment. For example, on form 11A.2.5 there are three types of boilers. Hot water, low-pressure steam, and high-pressure steam. This single form will be used to gather data on all three types of boilers. Facility equipment has been divided into two categories: *power generation and distribution equipment* and *HVAC equipment.* Table 11-1 lists power generation and distribution equipment; Table 11-2 lists HVAC equipment.

Table 11-1—Power generation and distribution equipment

Form number	Equipment class
11A.1.1	Battery
11A.1.2	Battery charger
11A.1.3	Cable/conductor
11A.1.4	Capacitor/capacitor bank
11A.1.5	Circuit breaker
11A.1.6	Control panel
11A.1.7	Engine
11A.1.8	Fuel distribution system
11A.1.9	Tank
11A.1.10	Fuse
11A.1.11	Gauge
11A.1.12	Generator assembly
11A.1.13	Inverter
11A.1.14	Lightning arrestor
11A.1.15	Meter
11A.1.16	Poles and cross members
11A.1.17	Transformer
11A.1.18	Relay
11A.1.19	Rectifier
11A.1.20	SCADA system
11A.1.21	Switchboxes/panels
11A.1.22	UPS, uninterruptible power supply
11A.1.23	Voltage regulator

Table 11-2—HVAC equipment

Form number	Equipment name
11A.2.1	Accumulator
11A.2.2	Air dryer
11A.2.3	Air-handling unit
11A.2.4	Blower
11A.2.5	Boilers
11A.2.6	Cabinet heater (radiator)
11A.2.7	Chiller
11A.2.8	Compressor
11A.2.9	Condenser
11A.2.10	Control panel
11A.2.11	Convector
11A.2.12	Cooling tower
11A.2.13	Damper
11A.2.14	Direct-fired furnace
11A.2.15	Evaporator
11A.2.16	Fan
11A.2.17	Filter
11A.2.18	Heat exchanger
11A.2.19	Humistat
11A.2.20	Motor, electrical
11A.2.21	Piping
11A.2.22	Pressure control
11A.2.23	Pump
11A.2.24	Strainer
11A.2.25	Thermostat
11A.2.26	Transducer
11A.2.27	Valve

Annex 11A

(informative)

Data collection forms

11A.1.1 Battery

Today's date ___________ Facility name/ID ________________________

Equipment facility ID/name _____________________________________

Manufacturer _____________________ Date of manufacture____________

In-service date ____

Battery installed in equipment ___________________________________

Parent system ____

Battery type:

Dry cell ____

Lithium ion ___ Nickel metal hydride ___ Nickel cadmium ___

Wet cell, lead acid ____

Gel cell ____

Ratings:

Voltage _____________V

Ampere hour _____________ Ah

Battery purpose: Backup ___ Load ________ VA

Constant power ___ Load ________ VA

Does the battery supply power to a critical function? Yes ___ No ___

Charger in use? Yes ___ No ___

Charger: Manufacturer _____________________

Ratings: Voltage _______ V Current _______ A

Is this charger used for more than a single battery? No ___ How many? ___

What is the time to 80% discharge at operational load? ___________ h

Is there a spare on-site for this battery? Yes ___ No ___

What periodic maintenance is performed on the battery and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Is a maintenance log kept for this battery? Yes ___ No ___

Has this device or any components been replaced due to failure? Yes ___ No ___

At what interval is the battery replaced? _____________________

11A.1.2 Battery charger

Page 1

Today’s date ___________ Facility name/ID ________________________

Equipment facility ID/name _____________________________________

Manufacturer _____________________

Date of manufacture________________

In-service date __________________________________

Serial number _________________________________

Parent system __________________________________

Ratings:

Input voltage ___________ V

Output voltage __________ V

Output ampere __________ A

Is this device critical equipment? Yes___ No ___

Is there a spare on-site for this device? Yes___ How many? ____ No ___

What is the approximate time to replace this device? ________ h

Are records kept on maintenance and replacement? Yes___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.2 Battery charger (continued)

Page 2

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________ Date of manufacture___________
In-service date ______________________
Battery installed in equipment ___________________________________
Parent system ____

Battery type:
Dry cell ____
Lithium ion ___ Nickel metal hydride ___ Nickel cadmium ___
Wet Cell, lead acid ____
Gel cell ____
Ratings:
Voltage _____________ V Ampere hour _____________ Ah
Battery purpose: Backup ___ Load ________ VA
Constant power ___ Load ________ VA
Does the battery supply power to a critical function? Yes ___ No ___
Charger in use? Yes ___ No ___
Charger: Manufacturer _____________________
Ratings: Voltage _______ V Current _______ A
Is this charger used for more than a single battery? No ___ How many?___
What is the time to 80% discharge at operational load? ___________ h
Is there a spare on-site for this battery? Yes ___ No ___
What periodic maintenance is performed on the battery and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Is a maintenance log kept for this battery? Yes ___ No ___
Has this device or any components been replaced due to failure? Yes ___ No ___
At what interval is the battery replaced?_______________

11A.1.3 Cable/conductor

Today's date ___________ Facility name/ID ________________________

Equipment facility ID/name ______________________________________

Manufacturer ______________________ Date of manufacture___________

In-service date _____________________

Ratings:

kVA ____________

Operational load % kVA (if known) ____________% kVA

Is the conductor: Belowground ___ Aboveground___ Aerial ____ In conduit___

In tray____ Insulated ____ Open wire ____

Type: ac ___ dc ___

Voltage _____ V Length _________ ft

Is there a spare on-site for this device? Yes___ How many? ____ No ___

What is the approximate time to replace this device? ________ h

Is there a redundant loop available for this circuit? Yes ___ No ___

Are records kept on maintenance and replacement? Yes___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.4 Capacitor/capacitor bank

Today’s date ___________ Facility name/ID _________________________

Equipment facility ID/name _______________________________________

Manufacturer _______________________

In-service date ______________________

Ratings: kvar____________

Capacitive ___

Inductive ___

Resistive ___

Voltage ______________________V

Frequency ______________________ Hz

Cooling: Air ___

Forced air ___

Water ___

Other ____ Coolant name _________________

Is there a spare on-site for this device? Yes___ How many? ____ No ___

What is the approximate time to replace this device? ________ h

Is there a redundant device available for this capacitor? Yes ___ No ___

Are records kept on maintenance and replacement? Yes___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.5 Circuit breaker

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
In-service date ______________________
Parent system ___________________________________
Type: Fixed ___ Metal-clad ___ Molded case ___ Oil ___ Vacuum ___
Normally open ____ Normally closed ____
Ratings: Voltage _____________ V
Current _____________ A
Poles _____________
Interrupting capacity ________ A
Are spares on-site for this device? Yes ___ How many?_______? No ___
What is the approximate time to replace this device? ________ h
Is there a redundant circuit? Yes ___ No ___
Is critical equipment protected by this circuit breaker? Yes ___ No ___

Item number	Critical equipment name	Comments
1		
2		
3		
4		

Are records kept on maintenance and replacement? Yes___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.6 Control panel

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model__________
In-service date ______________________
Parent system ___________________________________
Ratings:
Voltage _____________ V
Current _____________ A
Frequency _____________ Hz
Phases 1 __ 2 __ 3 __
Does this panel control a critical device? Yes ___ No ___
Is there a spare on-site for this device? Yes___ How many? ____ No ___
What is the approximate time to replace this device? ________ h
Is there a redundant control panel available for this device? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.7 Engine

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model__________
In-service date ______________________
Parent system ___________________________________
Type: Diesel ___ Gasoline ___ Gas turbine ___
Number of cylinders: 4 ___ 6 ___ 8 ___ 12 ___
Displacement: ci __________ cc__________
Horsepower ____________ hp
Torque ____________ ft-lb
Weight ____________ lb
Starter type: Electric ___ Compressed air ___ Other ___
Is this engine a critical device? Yes ___ No ___
Is there a spare on-site for this device? Yes ___How many?_____ No ___
What is the approximate time to replace this device? ________ h
Is there a redundant engine available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	**Maintenance performed**	**Interval**	**Date last performed**	**Comments**
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	**In-service date**	**Date replaced**	**Comments**
1			
2			

11A.1.8 Fuel distribution system

Page 1

Today’s date ____________ Facility name/ID ___________________________

Equipment facility ID/name ____

Type: Diesel ___ Gasoline __ Gas turbine __ Heating oil ___ LP __
Natural gas ___

Dewater strainer:
Manufacturer ______________________________________
Model ____
Serial number ______________________________________
In-service date _____________________________________

Tank heater
Manufacturer ______________________________________
Model ____
Serial number ______________________________________
In-service date _____________________________________

Transfer pump
Manufacturer ______________________________________
Model ____
Serial number ______________________________________
In-service date _____________________________________

Filter
Manufacturer ______________________________________
Model ____
Serial number ______________________________________
In-service date _____________________________________

Is there a redundant fuel distribution system? Yes ___ No ___
List the systems supplied by this fuel distribution system.

Item number	System name	Critical system Yes/No	Comments
1			
2			
3			
4			

11A.1.8 Fuel distribution system (continued)

Page 2

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				
5				
6				
7				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			
4			
5			
6			
7			

11A.1.9 Tank

Today's date ___________ Facility name/ID _________________________

Equipment facility ID/name _______________________________________

Manufacturer _______________________

Model___________________

In-service date ______________________

Capacity _______ gal

Construction material____

Parent system ______________________________________

Type: Fuel___ Receiver ___ Water ___ Day ___

Fuel: Diesel ___ Gasoline ___ Heating oil ___ LP ___ Natural gas ___

Receiver: Refrigerant Type: R12 ___ R134A ___ R22 ___ Other ___

Water: Boiler feed ___ Condensate ___ Expansion ___ Water treatment ___

Day: Approximate running time ___________ h

Is there a redundant tank available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.10 Fuse

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________
In-service date ______________________
Type: Fast acting ___ Slow-blow ___ Time delay ___
Ratings:
Voltage _____________ V
Interrupting Capacity ________ A

Is critical equipment protected by this fuse? Yes ___ No ___

Is there a spare on-site for this fuse? Yes___ How many? ____ No ___
What is the approximate time to replace this fuse? ________ h
Is there a redundant fuse available for this circuit? Yes ___ No ___

Item number	Critical equipment name	Comments
1		
2		
3		
4		
5		

Are records kept on fuse replacement? Yes ____ No ___
Written ___ Computerized ___
What replacement has been done and at what interval?

Item number	In-service date	Date replaced	Comments
1			
2			
3			
4			
5			

11A.1.11 Gauge

Today’s date ___________ Facility name/ID _________________________

Equipment facility ID/name _______________________________________

Manufacturer _______________________

Model____________________

Serial number ___________________

In-service date ______________________

Parent system ___________________________________

Type: Fuel ___

Diesel ___ Gasoline ___ Heating oil ___

Vacuum ___

Pressure ___

Hydraulic ___ Pneumatic ___

Does this gauge monitor a critical device? Yes ___ No ___

Is there a spare on-site for this gauge? Yes___ How many? ____ No ___

What is the approximate time to replace this device? ________ h

Is there a redundant gauge available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.12 Generator assembly

Page 1

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Assembly manufacturer ______________________
Assembly model____________________________
Assembly serial number _____________________
Assembly in-service date _____________________
Rated kW _________________________________
Engine manufacturer_________________________
Engine model_______________________________
Engine serial number_________________________
Engine in-service date ________________________
Generator manufacturer_______________________
Generator model_____________________________
Generator serial number_______________________
Generator in-service date ______________________
Purpose: Primary power ___ Standby power___
Type: Diesel ___ Gasoline ___ Gas turbine ___
Packaged ___ Unpackaged ___
Ratings:
Engine: Number of cylinders 4 ___ 6 ___ 8 ___ 12 ___
Displacement ci __________ cc__________
Horsepower ____________ hp
Torque ____________ ft-lb
Weight ____________ lb
Starter type: Electric ___ Compressed air ___ Other ___
Turbine shaft rpm ___________
Generator: kVA/kW ___________
Voltage ___________ V
Current ___________ A
Frequency___________Hz
Power factor ___________ PF
Phase: Single ___ 2 ___ 3 ___ Other ___
Is this generator a critical device? Yes ___ No ___
Is there a spare on-site for this device? Yes___ How many? ____ No ___
What is the approximate time to replace this device? ________ h
Is there a redundant generator available? Yes ___ No ___
Is the redundant generator brought online automatically? Yes ___ No ___

11A.1.12 Generator assembly (continued)

Page 2

Today's date ___________ Facility name/ID _________________________

Are records kept on maintenance and replacement? Yes___ No ___
Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				
5				
6				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			
4			
5			
6			

11A.1.13 Inverter

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________
Purpose: Primary power ___ Standby power___

Ratings:
Input voltage _________ V
Output voltage _________ V
Frequency _________ Hz
Waveform _________
Output overload protection _________
Output power factor _________ PF
Response time _________
Battery protection levels _________

Does this inverter supply a critical device? Yes ___ No ___
Is there a spare on-site for this inverter? Yes___ How many? ____ No ___
What is the approximate time to replace this inverter? ________ h
Is there a redundant inverter available? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.14 Lightning arrestor

Today's date ___________ Facility name/ID ________________________

Equipment facility ID/name _____________________________________

Manufacturer ______________________

Model____________________________

Serial number _____________________

In-service date ____________________

Ratings:

Voltage ___________ V

Discharge current ___________ A

Are spares on-site for this device? Yes ___ No ___ How many? _______

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	**Maintenance performed**	**Interval**	**Date last performed**	**Comments**
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	**In-service date**	**Date replaced**	**Comments**
1			
2			

11A.1.15 Meter

Today's date ___________ Facility name/ID _________________________

Equipment facility ID/name _______________________________________

Manufacturer _______________________

Model_____________________________

Serial number ______________________

In-service date _____________________

Parent system ___________________________________

Type: Electric ___ Fuel ___ Water ___

Digital ___ Analog ___

Does this meter monitor a critical device? Yes ___ No ___

Is there a spare on-site for this meter? Yes___ How many?____ No ___

What is the approximate time to replace this meter? ________ h

Is there a redundant meter available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.16 Poles and cross members

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
In-service date _______________________
Pole ID# ______________
Pole height ____________ ft
Pole diameter ____________ in
Cross member length ______ ft
Voltage ____________ V
Number of wires __________
Transformer: Yes ___ No ___
Number of taps _______
Telephone: Yes ___ No ___ Cable number of pairs ______
Cable TV: Yes ___ No ___
Guide wire: Yes ___ No ___ Number of ____

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.17 Transformer

Today’s date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
In-service date _____________________
Serial number ______________________
Parent system ___________________________________
Type: Dry ___ Liquid ___
Step up ____ Step down ____ Isolation ___

Rating: kVA _____________
Primary voltage_____________ V
Primary current_____________ A
Secondary voltage_____________ V
Secondary current_____________ A

Is this transformer a critical device? Yes ___ No ___
Is there a spare on-site for this transformer? Yes___ How many?____ No ___
What is the approximate time to replace this transformer? ________ h
Is there a redundant transformer available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.18 Relay

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
In-service date _____________________
Parent system ___________________________________
Class: General purpose ___ Latching ___ Impulse ___ Stepping ___
Sequence ___ Differential ___
Type: Armature ___ Hybrid ___ Solid-state ___ Time delay
Contact Type:Normally open ___ Normally closed ___ Number of poles ____
Complex _____ Number of poles ____
Ratings: Contacts: Voltage ______ V Current ______ A
Coil: Voltage ______ Resistance ______
Frequency_______ Hz
Use: Low level ___ (low current switching, mA)
Intermediate level ___ (up to 10 A)
Power ___ (excess of 10 A)
Special purpose ___
Does this relay control a critical device? Yes ___ No ___
Equipment name _______________________________
Is there a spare on-site for this relay? Yes___ How many?____ No ___
What is the approximate time to replace this relay? ________ h
Is there a redundant relay available? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.19 Rectifier

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model______________________________
In-service date ______________________
Parent system ___________________________________

Ratings:
Peak voltage ______________ V
Average forward current___________ A
Peak surge current ______________ A
Peak forward current_____________ A
Temperature range______________ °C / °F

Does this rectifier supply a critical device? Yes ___ No ___
Is there a spare on-site for this rectifier? Yes___ How many?____ No ___
What is the approximate time to replace this rectifier? ________ h
Is there a redundant rectifier available? Yes ___ No ___
Does the redundant rectifier automatically switch in-line? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.20 SCADA system

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
In-service date _____________________
Serial number ______________________
Parent system ___________________________________

List the systems this SCADA system control or monitors. Identify critical equipment.

Item number	Equipment name	Critical Yes/No	Comments
1			
2			
3			
4			

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			
4			

11A.1.21 Switchboxes/panels

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
In-service date _____________________
Parent system ___________________________________

Type: Disconnect ___ Transfer ___
Knife ___ Circuit breaker ___
Manual ___ Automatic ___
Rating: kVA _____
Voltage ____
Phase: Single ____ 2 ____ 3 ____

Does this switchbox/panel control critical equipment? Yes ___ No ___
Equipment name ______________________________
Is there a spare on-site for this switchbox/panel? Yes__ How many?____ No ___
What is the approximate time to replace this switchbox/panel? ________ h
Is there a redundant switchbox/panel available? Yes ___ No ___

Does the switchbox/panel provide lock-out provisions? Yes ___ No ___
Does the switchbox/panel provide circuit protection? Yes ___ No ___
Fuse ___ Circuit breaker ___ Solid-state ___
Number of circuits ________
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.22 UPS, uninterruptible power supply

Today’s date ___________ Facility name/ID ________________________
Equipment facility ID/name ______________________________________
Manufacturer _______________________
Model_____________________________
In-service date _____________________
Serial number ______________________
Parent system ___________________________________

Rating: kVA ___________
Input voltage___________ V
Output voltage___________ V

What type of equipment is connected to this UPS? Identify critical equipment.
____
____
____
____

Is there a spare on-site for this UPS? Yes___ How many?____ No ___
What is the approximate time to replace this UPS? ________ h
Is there a redundant UPS available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.1.23 Voltage regulator

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
In-service date _____________________
Parent system ___________________________________

Rating: Input voltage___________ V
Input current___________ A
Output voltage___________ V
Output current___________ A

Does this voltage regulator control critical equipment? Yes ___ No ___
Equipment name _____________________________
Is there a spare on-site for this voltage regulator?Yes___ How many?____
No ___
What is the approximate time to replace this voltage regulator? ________ h
Is there a redundant voltage regulator available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.1 Accumulator

Today's date ___________ Facility name/ID _________________________

Equipment facility ID/name _______________________________________

Manufacturer _______________________

Model_____________________________

Serial number ______________________

In-service date _____________________

Parent system ___________________________________

Capacity (volume)__________________ gal/L

Is the accumulator pressurized? Yes ___ No ___ Maximum pressure _______psi

Is this accumulator critical equipment? Yes ___ No ___

Is there a spare on-site for this accumulator? Yes___ How many?____ No ___

What is the approximate time to replace this accumulator? ________ h

Is there a redundantly connected accumulator available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.2 Air dryer

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________
Location____

Maximum pressure____________________

Pipe size _______

Is this air dryer critical equipment? Yes ___ No ___
Is there a spare on-site for this air dryer? Yes___ How many?____ No ___
What is the approximate time to replace this air dryer? ________ h
Is there a redundantly connected air dryer available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.3 Air-handling unit

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model______________________________
Serial number ______________________
In-service date _____________________

Nominal cooling capacity________________ ton
Nominal heating capacity________________ Btu
Nominal air volume ____________________ cfm
Supply power: Voltage __________
Phase: Single ___ 2 ___ 3 ___
Frequency__________
Humidity control: None ___ Pan ___ Spray ___
Air filter: Yes ___ No ___
Evaporator type: Coil_____ Fan ______
Face area ______ Diameter ______ in
Rows/fins ______ Air volume ______ cfm
Operating charge ___ kg Motor ______ hp
Motor ______ rpm
Refrigerant: R12 ___ R134A ___ R22 ___
Is this air-handling unit critical equipment? Yes ___ No ___
Is there a spare on-site for this air-handling unit? Yes__ How many?____ No ___
What is the approximate time to replace air-handling unit? ________ h
Is there a redundantly connected air-handling unit available? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.4 Blower

Today’s date ____________ Facility name/ID ___________________________

Equipment facility ID/name ____

Manufacturer _________________________

Model_______________________________

Serial number ________________________

In-service date _______________________

Parent system ______________________________________

Capacity __________ cfm

Maximum __________ rpm

Is this blower unit critical equipment? Yes ___ No ___

Is there a spare on-site for this blower unit? Yes___ How many?____ No ___

What is the approximate time to replace blower unit? _________ h

Is there a redundantly connected blower unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.5 Boilers

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Type: Hot water ___ Low-pressure steam ___ High-pressure steam ___
Fuel: Natural gas ___ LP ___ Oil ___ Other ___
Heating size _______________ Btu
Boiler capacity _____________ gal
Pressure _______________ psi
Efficiency_______________ %
Pilot light ____ Electronic igniter _____
Does the system contain zones? Yes ___ No ___ How many? _________
Does the system contain a pump? Yes ___ No ___ How many? _________
Zone valve: Manufacturer _______________________
Model _____________________________
Pump: Manufacturer _______________________
Model _____________________________
Expansion tank: Manufacturer ______________________
Model _____________________________
Does the system contain a pressure safety valve? Yes ___ No ___
Is this a critical HVAC system? Yes ___ No ___
Is there a spare on-site for this boiler? Yes___ How many?____ No ___
What is the approximate time to replace the boiler? ________ h
Is there a redundantly connected boiler available? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.6 Cabinet heater (radiator)

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________
Type: Electric ___ Steam ___ Hot water ___
Electrical: Supply voltage ______ V
Current _____ A
Phase: Single ___ 2___ 3 ___
Frequency ____ Hz
Watts _______ W
Steam or hot water: Connection sizes ________ in
Pressures ________ psi
Heat capacity _________ Btu

Is this a critical HVAC system? Yes ___ No ___
Is there a spare on-site for this cabinet heater? Yes___ How many?___ No ___
What is the approximate time to replace the cabinet heater? ________ h
Is there a redundantly connected cabinet heater available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	**Maintenance performed**	**Interval**	**Date last performed**	**Comments**
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	**In-service date**	**Date replaced**	**Comments**
1			
2			

11A.2.7 Chiller

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________

Capacity (ton, kW, Kcal/h)______________________
Number of compressors_______________________
Compressor motor: Manufacturer ____________ Model ___________
Horsepower ____________ Voltage ___________
Motor frame number ___________
Water flow rate _____________ gal/min, L/S
Refrigerant type: R12 ___ R134a ___ R22 ___ Other ___
Refrigerant charge _______ kg

Is this a critical HVAC system? Yes ___ No ___
Is there a spare on-site for this chiller unit? Yes___ How many?____ No ___
What is the approximate time to replace chiller unit? ________ h
Is there a redundantly connected chiller unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.8 Compressor

Today’s date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ________________________
Use Air ________ HVAC _______
Type: Electric ___ Gasoline ___ Diesel ___
Ratings: Motor/engine horsepower _______ hp
Engine displacement _______ ci/cc
Motor voltage _______ V
Motor rated current _______ A
Motor phase: Single___ 2 ___ 3 ___
Motor speed ________ rpm
CFM output ________ cfm
Maximum rated pressure ________ psi
Receiver capacity ________ gal
Refrigerant volume ______________ cc/L/pt/qt
Refrigerant Type: R12___ R134a___ R22 ___ Other _____
Is this compressor unit critical equipment? Yes ___ No ___
Is there a spare on-site for this compressor unit? Yes__ How many?____ No ___
What is the approximate time the compressor unit? ________ h
Is there a redundantly connected compressor unit available? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.9 Condenser

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________
Ratings: Capacity ______________ kW
Fan diameter ______________ in
Fan motor horsepower ______________ hp
Fan motor speed ______________ rpm
Fan motor voltage ______________ V
Fan motor phase: Single ___ 2 ___ 3 ___
Fan motor current ______________ A
Flow rate ______________ cfm
Refrigerant volume ______________ cc/L/pt/qt
Refrigerant type: R12___ R134a___ R22 ___ Other _____
Is this condenser unit critical equipment? Yes ___ No ___
Is there a spare on-site for this condenser unit? Yes___ How many?____ No ___
What is the approximate time to replace the condenser unit? ________ h
Is there a redundantly connected condenser unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.10 Control panel

Today's date ___________ Facility name/ID _________________________

Equipment facility ID/name _______________________________________

Manufacturer _______________________

Model_____________________________

Serial number ______________________

In-service date _____________________

Parent system ___________________________________

Is this HVAC control panel on critical equipment? Yes ___ No ___

Is there a spare on-site for this HVAC control panel? Yes___ How many?____

No ___

What is the approximate time to replace HVAC control panel? ________ h

Is there a redundantly connected HVAC control panel available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.11 Convector

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________

Type: Electric _____ Steam _____
Ratings: Heat output ___________ Btu/kW
Voltage ___________ V
Phase: Single ___ 2 ___ 3 ___
Current ___________ A
Pressure, maximum ________ psi
Is this convector unit critical equipment? Yes ___ No ___
Is there a spare on-site for this convector unit? Yes___ How many?____ No ___
What is the approximate time to replace the convector unit? ________ h
Is there a redundantly connected convector unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.12 Cooling tower

Today’s date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________

Type: Atmospheric____ Evaporative ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				

Has this device been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			
4			
5			
6			

11A.2.13 Damper

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________

Type: Electric ___ Vacuum ___
Ratings: Temperature range _________°C / °F
Duct size _________ ft^2
Voltage _________ V
Phase: Single ___ 2 ___ 3 ___
Current ___________ A
Motor NEMA frame # ___________
Vacuum, operating ___________ in Hg
Vacuum, maximum ___________ in Hg

Is this damper unit critical equipment? Yes ___ No ___
Is there a spare on-site for this damper unit? Yes___ How many?____ No ___
What is the approximate time to replace the damper unit? ________ h
Is there a redundantly connected damper unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.14 Direct-fired furnace

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________

Ratings: Heat output ________ Btu
Fuel: Natural gas ___ LP ___ Oil ___ Other ________
Voltage _________ V
Phase: Single ___ 2 ___ 3 ___
Current ___________ A
Motor NEMA frame # ___________
Is this direct-fired furnace critical equipment? Yes ___ No ___
Is there a spare on-site for this direct-fired furnace? Yes___ How many?____
No ___
What is the approximate time to replace the direct-fired furnace? ________ h
Is there a redundantly connected direct-fired furnace available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			
4			
5			
6			

11A.2.15 Evaporator

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________
Type: Air _____ Liquid ____
Ratings: Heat transfer rate _________ Btu/h
Voltage _________ V
Phase: Single ___ 2 ___ 3 ___
Current ___________ A
Motor NEMA frame # ___________
Liquid type: Water ___ Brine ___ Other ___
Liquid capacity __________ gal
Refrigerant type: R12 ___ R134a ___ R22 ___
Other _______
Is this evaporator unit critical equipment? Yes ___ No ___
Is there a spare on-site for this evaporator unit? Yes___ How many?____ No ___
What is the approximate time to replace the evaporator unit? ________ h
Is there a redundantly connected evaporator unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

11A.2.16 Fan

Today's date ___________ Facility name/ID ________________________
Equipment facility ID/name ______________________________________
Manufacturer ______________________
Model____________________________
Serial number _____________________
In-service date ____________________
Parent system ________________________________
Type: Centrifugal ___ Propeller/disc ___ Tube-axial ___ Vane-axial ___
Ratings: Size __________ in
Output __________ cfm
Number of blades __________
Motor horsepower __________ hp
Motor speed __________ rpm
Voltage _________ V
Phase: Single ___ 2 ___ 3 ___
Current ___________ A
Motor NEMA frame # ___________
Is this fan critical equipment? Yes ___ No ___
Is there a spare on-site for this fan? Yes___ How many?____ No ___
What is the approximate time to replace the fan? ________ h
Is there a redundantly connected fan available? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

11A.2.17 Filter

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________
Type: Mechanical ______ Electrical ______
Use: Air ____ Lube oil ___ Fuel oil ___ Gasoline ___ Tempest ___
HEMP ___
Ratings: Inlet size________ ID, in^2, ft^2
Outlet size ________ ID, in^2, ft^2
Inlet pressure, maximum ________ psi
Outlet pressure, maximum ________ psi
Flow rate ________ gal/min, cfm
Temperature, maximum ______°C / °F
Filter element ________________________
EMI/RFI suppression ____________ dB
Voltage, maximum____________ V
Current, maximum ____________ A
Is this filter connected to critical equipment? Yes ___ No ___
Is there a spare on-site for this filter? Yes___ How many?____ No ___
What is the approximate time to replace the filter? ________ h
Is there a redundantly connected filter available? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			

11A.2.18 Heat exchanger

Today's date ____________ Facility name/ID ___________________________

Equipment facility ID/name ____

Manufacturer _________________________

Model_______________________________

Serial number ________________________

In-service date _______________________

Parent system ______________________________________

Heat transfer rate ____________ Btu

Efficiency ____________ %

Is this heat exchanger unit critical equipment? Yes ___ No ___

Is there a spare on-site for this heat exchanger unit? Yes___ How many?____

No ___

What is the approximate time to replace the heat exchanger unit? ________ h

Is there a redundantly connected heat exchanger unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

11A.2.19 Humistat

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________

Ratings: Voltage __________ V
Current __________ A
Control signal: Analog voltage ______ V
Digital level _________ V

Is this humistat unit critical equipment? Yes ___ No ___
Is there a spare on-site for this air humistat unit? Yes___ How many?___ No ___
What is the approximate time to replace the humistat unit? ________ h
Is there a redundantly connected humistat unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

11A.2.20 Motor, electrical

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________

Ratings: Motor horsepower __________ hp
Torque __________ ft-lb
Motor speed __________ rpm
Voltage _________ V
Phase: Single ___ 2 ___ 3 ___
Current ___________ A
Motor NEMA frame # ___________

Is this motor critical equipment? Yes ___ No ___
Is there a spare on-site for this motor? Yes___ How many?____ No ___
What is the approximate time to replace the motor? ________ h
Is there a redundantly connected motor available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

11A.2.21 Piping

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
In-service date _____________________
Parent system _____________________
Ratings: Size OD ___________ in
Size ID ___________ in
Length ___________ ft
Material/specification ___________/__________
Coupling type:
Compression ____
Solder ____
Threaded ____
Medium carried:
Hot domestic water ____
Cold domestic water ____
Sanitary water ____
Coolant ____
Chiller water ______
Steam ____
Is this piping critical equipment? Yes ___ No ___
What is the approximate time to replace the piping? ________ h
Is spare piping available? Yes ___ No ___
Is there a redundantly connected piping loop available? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

11A.2.22 Pressure control

Today’s date ___________ Facility name/ID _________________________

Equipment facility ID/name _______________________________________

Manufacturer _______________________

Model_____________________________

Serial number ______________________

In-service date _____________________

Parent system ___________________________________

Ratings: Maximum pressure ____________ psi

Accumulator capacity ____________ gal

Is this pressure control unit critical equipment? Yes ___ No ___

Is there a spare on-site for this pressure control unit? Yes___ How many?____

No ___

What is the approximate time to replace the pressure control unit? ________ h

Is there a redundantly connected pressure control unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	**Maintenance performed**	**Interval**	**Date last performed**	**Comments**
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	**In-service date**	**Date replaced**	**Comments**
1			
2			
3			

11A.2.23 Pump

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model______________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________

Ratings: Flow rate __________ gal/min
Maximum pump pressure __________ psi
Maximum operating temperature__________ °C / °F
Motor horsepower __________ hp
Torque __________ ft-lb
Motor speed __________ rpm
Voltage _________ V
Phase: Single ___ 2 ___ 3 ___
Current ___________ A
Motor NEMA frame # ___________
Is this pump unit critical equipment? Yes ___ No ___
Is there a spare on-site for this pump unit? Yes___ How many?____ No ___
What is the approximate time to replace the pump unit? ________ h
Is there a redundantly connected pump unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

11A.2.24 Strainer

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________

Ratings: Inlet/outlet size ________/_______ in
Construction material ________________
Maximum inlet pressure ________ psi
Max operating temperature _________ °C / °F
Fluid:
Coolant ____
Duplex fuel/lube oil ____
Fuel oil ____
Lube oil ____
Water ____

Is this strainer unit critical equipment? Yes ___ No ___
Is there a spare on-site for this strainer unit? Yes___ How many?____ No ___
What is the approximate time to replace the strainer unit? ________ h
Is there a redundantly connected strainer unit available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

11A.2.25 Thermostat

Today's date ___________ Facility name/ID _________________________

Equipment facility ID/name _______________________________________

Manufacturer _______________________

Model_____________________________

Serial number ______________________

In-service date _____________________

Parent system ___________________________________

Ratings:Type: Electronic _____ Millivolt ____ 24 Vac _____

Heating ___ Heating & cooling ___

Battery backup? Yes ___ No ___

Does this thermostat control critical equipment? Yes ___ No ___

Is there a spare on-site for this thermostat? Yes___ How many?____ No ___

What is the approximate time to replace the thermostat? ________ h

Is there a redundantly connected thermostat available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___

Written ___ Computerized ___

What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

11A.2.26 Transducer

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________

Ratings: Type: Flow ___ Temperature ___ Pressure ___ Vacuum ___
Maximum operating temperature ________ °C / °F
Maximum operating pressure/vacuum ________ psi/mmHg
Maximum operating flow ________ gal/min
Operating voltage: ac ____ Vac dc _______ Vdc
Output voltage: ac ____ Vac dc _______ Vdc
Does this transducer control critical equipment? Yes ___ No ___
Is there a spare on-site for this transducer? Yes___ How many?____ No ___
What is the approximate time to replace the transducer? ________ h
Is there a redundantly connected transducer available? Yes ___ No ___

Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	**Maintenance performed**	**Interval**	**Date last performed**	**Comments**
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	**In-service date**	**Date replaced**	**Comments**
1			
2			
3			

11A.2.27 Valve

Today's date ___________ Facility name/ID _________________________
Equipment facility ID/name _______________________________________
Manufacturer _______________________
Model_____________________________
Serial number ______________________
In-service date _____________________
Parent system ___________________________________
Ratings:Type: Diverting ___ Mixing ___ Ball ___ Butterfly ___ Check ___
Control ___ Expansion ___ Gate ___ Globe ___ Plug ___
Relief ___ Suction ___
Position: NC _____ NO ______
Control: Manual ___ Electrical ___ Pneumatic ___
Voltage ________ Vac, Vdc
Current _________ Aac, Adc
Construction material _________________
Maximum operating temperature__________ °C / °F
Maximum operating pressure__________ psi
Input size OD __________ in
Outlet size OD __________in
Is this valve in a critical system? Yes ___ No ___
Is there a spare on-site for this valve? Yes___ How many?____ No ___
What is the approximate time to replace the valve? ________ h
Is there a redundantly connected valve in the system? Yes ___ No ___
Are records kept on maintenance and replacement? Yes ___ No ___
Written ___ Computerized ___
What periodic maintenance is performed and at what interval?

Item number	Maintenance performed	Interval	Date last performed	Comments
1				
2				
3				
4				

Has this device or any components been replaced due to failure?

Item number	In-service date	Date replaced	Comments
1			
2			
3			

Annexes A–Q

Annexes A through Q can be viewed and/or downloaded at the following IEEE URL:

http://standards.ieee.org/downloads/493/493-2007/

Annex A—Report on Reliability Survey of Industrial Plants—Parts I, II, and III

Annex B—Report on Reliability Survey of Industrial Plants—Parts IV, V, and VI

Annex C—Cost of Electrical Interruptions in Commercial Buildings

Annex D —Reliability of Electric Utility Supplies to Industrial Plants

Annex E—Report of Switchgear Bus Reliability Survey of Industrial Plants and Commercial Buildings

Annex F—Working Group Procedure for Conducting an Equipment Reliability Survey

Annex G —Report of Transformer Reliability Survey—Industrial Plants and Commercial Buildings

Annex H—Report of Large Motor Reliability Survey of Industrial and Commercial Installations—Parts I, II, and III

Annex I—Reliability Study of Cable, Terminations, and Splices by Electric Utilities in the Northwest

Annex J—Summary of CIGRE 13.06 Working Group World Wide Reliability and Maintenance Cost Data on High Voltage Circuit Breakers above 63 kV

Annex K—Report of Circuit Breaker Reliability Survey of Industrial and Commercial Installations

Annex L—Reliability Survey of 600 to 1800 kW Diesel and Gas-Turbine Generating Units

Annex M—Reliability/Availability Guarantees of Gas Turbines and Combined Cycle Generating Units

Annex N—Transmission Line and Equipment Outage Data

Annex O—Interruption Costs, Consumer Satisfaction, and Expectations for Service Reliability

Annex P—Survey Results of Low-Voltage Breakers as Found during Maintenance Testing

Annex Q—Survey of Reliability and Availability Information for Power Distribution, Power Generation, and HVAC Components for Commercial, Industrial, and Utility Installations

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