CAYMAN ISLANDS

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THE ELECTRICITY REGULATORY AUTHORITY LAW (2010 REVISION)

THE ELECTRICITY REGULATORY AUTHORITY (STANDARD OF PERFORMANCE) RULES, 2012

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ARRANGEMENT OF RULES

CAYMAN ISLANDS

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THE ELECTRICITY REGULATORY AUTHORITY (STANDARD OF PERFORMANCE) RULES, 2012

In exercise of the powers conferred by sections 66 and 89(3) of the Electricity Regulatory Authority Law (2010 Revision), the Authority, after consultation with the Governor and the licensee, makes the following Rules -

1. These Rules may be cited as the Electricity Regulatory Authority (Standard of Performance) Rules, 2012. Citation

2. In these Rules - Definitions

"EAF" means the Equivalent Availability Factor as defined by ANSI/IEEE Standard 762-1987(R2002) (set out in Schedule 1) which is the fraction of the maximum generation that could be provided if limited only by outages and deratings (per unit or plant basis) and is calculated as available generation divided by maximum generation multiplied by 100% (unit or total plant basis); Schedule 1

"IG" means Imperial Gallon, corrected to ISO standard conditions;

"Initial Period" means the period commencing on 1st January, 2011, and terminating on 31st December, 2012;

"Net Fuel Efficiency" means the annual total plant net actual generation divided by the annual total plant fuel consumption for electrical generation during the year;

"planned outage" means the state in which a unit is unavailable due to inspection, testing or overhaul and that outage is scheduled in advance of its occurrence;

"Planned Outage Factor" means planned outage hours divided by the period hours and multiplied by 100% when measured on a per unit basis or the sum of the planned outage hours multiplied by the gross maximum generation per unit for all of the units in the active state and then divided by the gross maximum generation for the plant on a total plant basis;

"SAIDI" means the "System Average Interruption Duration Index" which is the total hours, on average, that a customer could expect to be without electricity over a year, calculated as the sum of the duration of each customer interruption (in hours), divided by the total number of connected customers averaged over the year;

"SAIFI" means the "System Average Interruption Frequency Index" which is the number of occasions per year when each customer could, on average, expect to experience an unplanned interruption, calculated as the total number of customer interruptions, divided by the total number of connected customers averaged over the year and unless otherwise stated, SAIFI excludes momentary interruptions;

"Service Territory" means the entire area of the island of Grand Cayman;

"T&D Licensee" means Caribbean Utilities Company Ltd. as the exclusive holder of the T&D licence for the Service Territory under the Law;

"Target" means the quantity or figure that shall provide the benchmark for Caribbean Utilities Company Ltd.'s performance;

"The Generator" means Caribbean Utilities Company Ltd. as the holder of a generation licence for the Service Territory under the Law; and

"Zone of Acceptability" means the range above and below the Target that is exempt from any reward or penalty, intended to allow for the normal variation of the performance measures.

Initial Period

3. The T&D Licensee shall, during the Initial Period, meet with the Technical Committee of the Authority on a quarterly or semi-annual basis, as requested by the Technical Committee, to discuss its performance during the prior period in all areas related to these standards.

Rewards and penalties

4. (1) Rewards and penalties shall be excluded from the calculation of changes to the base rate.

(2) The effect of any rewards or penalties recognized in the applicable financial balances of the T&D Licensee shall be removed before calculating Return on Rate Base in determining the RCAM annual base rate adjustment.

T&D standards and requirements

5. (1) The T&D Licensee shall, for SAIDI and SAIFI during the Initial Period, adopt its average historical performance over the past ten years, excluding the calendar years 2005 and 2006, as the Targets.

(2) The T&D Licensee shall, as it has in the past, measure SAIDI and SAIFI in the future according to the methodology prescribed in the IEEE Standard No. 1366 set out in Schedule 2.

Schedule 2

(3) The annual Target for SAIDI and SAIFI shall exclude any year substantially affected by an event of force majeure, as defined in the T&D licence and generation licence, for up to two years, unless otherwise approved by the Authority.

(4) In paragraph (3), "substantially affected" means an event which causes SAIDI and SAIFI to vary by more than 10% from the Target figure.

(5) The T&D Licensee shall request and receive the Authority's approval for such exclusions.

(6) Using this metric during 2011, the SAIDI shall be 5.5 hours per year, and the SAIFI Target shall be 4.2 interruptions per year.

(7) The Zone of Acceptability shall be a range 10% above and below the foregoing Targets, rounded to the nearest tenth, on an annual basis.

(8) During 2011, the ranges shall be -

(a) 5.0 to 6.1 hours per year for SAIDI, using the 5.5 hour Target, plus and minus 10%, and
(b) 8 to 4.6 interruptions per year for SAIFI, using the 4.2 Target, plus and minus 10%.

(9) The increments for potential rewards and penalties shall be tenths of an hour (six minute increments) for SAIDI, and 0.1 interruptions per year for SAIFI, each valued at five thousand dollars per increment, subject to a maximum of one hundred thousand dollars during the Initial Period.

(10) There shall be, during the Initial Period, no reward or penalty for better or worse performance outside this range.

(11) The T&D Licensee shall report, with monthly detail, its SAIDI and SAIFI performance on or before 15th January, 15th April, 15th July and 15th October of each year, in conjunction with the quarterly management reports that the T&D Licensee shall provide to the Authority.

(12) The reports shall enable the Authority and the T&D Licensee to determine during the year whether performance is likely to be within or outside the Zone of Acceptability for that year and, if it is likely that performance shall be outside the Zone of Acceptability, the Authority and the T&D Licensee shall discuss the reasons for such performance, and if it is expected to be worse than the relevant limit of the Zone of Acceptability, the T&D Licensee shall propose and implement corrective actions, which in its judgment will correct the likely deficiency.

(13) The T&D Licensee shall, in January of each year, immediately following the submission of its report to the Authority of its prior year's performance on SAIDI and SAIFI, file a report with the Authority indicating whether a reward or penalty is due, based on the prior year's performance.

(14) Where a reward or penalty is due, the T&D Licensee shall recommend changes to modify monthly consumer billings to reflect any applicable reward or penalty, using the T&D Licensee's forecast of sales to spread those amounts evenly over the balance of the year so that the balance of any reward due to or penalty imposed on, the T&D Licensee shall be zero at the end of that year.

(15) A recommendation made under paragraph (14) shall be approved by the Authority prior to its implementation and the T&D Licensee shall, upon implementation, establish a tracking account to monitor the balance in this account.

(16) Rewards and penalties shall be reflected as a "z factor" on a consumer's bill.

(17) The T&D Licensee shall, in January, in the report to the Authority on its annual performance for the prior year, provide information to the Authority on the means by which it intends to meet the T&D standards for the coming year.

(18) The T&D Licensee shall, within six weeks of the date of commencement of these Rules, provide a recommendation for the Authority's consideration for a performance standard for T&D losses.

(19) The T&D Licensee shall, together with the recommendation, provide the Authority with the data for the performance standard for at least the preceding two years.

(20) The T&D Licensee shall include this figure in its quarterly performance reports to the Authority, with monthly detail, and by 1st November of

each year, the T&D Licensee shall justify the level of anticipated T&D losses for the coming year, and provide notice of the dates of any planned T&D outages.

Customer service standards

6. (1) The T&D Licensee shall measure the customer service standards specified using the following figures specified as indicative Targets -

(a) the time it takes for the T&D Licensee to reconnect customers after an outage - a maximum of twenty-four hours;
(b) connection of new accounts - a maximum of seven calendar days;
(c) reconnection after shutoff for non-payment, once payment is made - a maximum of twenty-four hours; and
(d) response time to billing complaints - a maximum of ten business days.

(2) The reconnection standards in paragraphs (a) and (c) shall be measured in terms of hours, and the connection and response time standards in paragraphs (b) and (d) shall be measured in parts of days.

(3) The T&D Licensee shall collect comprehensive data to document its performance on these measures of customer service during the Initial Period.

(4) The Authority shall, upon the compilation and submission of the data to document performance pursuant to paragraph (3), review the performance to determine Target, Zone of Acceptability and the level of reward or penalty for future performance standards.

(5) There shall be no rewards or penalties until the Authority has determined the Target, Zone of Acceptability, and an appropriate level of reward or penalty.

(6) The T&D Licensee shall, during the Initial Period, provide quarterly reports with monthly detail on the performance for each of the customer service standards.

(7) The T&D Licensee shall, within one month of the coming into force of these Rules, provide the Authority with any data that it has in relation to its performance to date of the measures set out in paragraph (1) for the Authority's consideration in setting performance standards for these measures.

(8) The Authority shall, following a review of the performance of the T&D Licensee, set standards, including rewards and penalties, for the measures set out in paragraph (1) and may, in addition, request the T&D Licensee to propose -

(a) Targets, Zones of Acceptability and rewards or penalties for these measures; and
(b) additional appropriate performance standards applicable to customer service

for the Authority's consideration and approval.

(9) The Authority may provide requests for modification to the T&D Licensee on its most recent customer satisfaction survey for regulatory purposes, and within four weeks of receiving the requests, the T&D Licensee shall submit an up-to-date customer satisfaction survey to the Authority for approval, which shall be utilized for its 2012 survey.

(10) The T&D Licensee shall conduct a customer satisfaction survey and provide a report to the Authority on the results every six months, including actions that the Licensee intends to take to maintain and increase satisfaction with its service and to mitigate dissatisfaction revealed by the survey.

(11) The Authority shall, in addition to the determination of the customer service standards, use the customer satisfaction survey to help determine whether the T&D Licensee is taking appropriate actions to provide, maintain and improve upon historical levels of customer service.

Generation performance standards and requirements

7. (1) There shall be an annual fuel efficiency standard which shall take into consideration any units that are planned to be added or retired during the year, and if the unit is not added or retired as planned or an event involving a unit occurs that was not planned, The Generator shall notify the Authority as soon as it becomes aware of this change, and shall file with the Authority a revised fuel efficiency standard for the overall generation fleet within fifteen business days of such notification.

(2) The Generator's Net Fuel Efficiency performance target for 2011 shall be set at 18.54 kWh/IG and The Generator shall -

(a) for 2011, use a range Zone of Acceptability of 18.03 to 19.14 kWh per IG, which is plus-or-minus 3.0% from the 18.58 kWh/IG target; and
(b) report its fuel efficiency performance quarterly, and monthlywithin fifteen days of each month's end, with monthly detail on the performance of each generating unit in the fleet.

(3) The Authority and The Generator shall use the reports required under paragraph (2)(b) to determine during the year whether performance is expected to be within or outside the Zone of Acceptability for the year.

(4) The Generator shall indicate in its quarterly reports whether the annual performance for Net Fuel Efficiency is likely to be outside of the Zone of Acceptability for the year and if any quarterly report indicates that the year end target will not likely be met, or upon the Authority's request, the Authority and The Generator shall discuss the reasons for such anticipated performance.

(5) Where The Generator is outside of the Zone of Acceptability, The Generator shall propose and implement corrective actions, which in its judgment will correct the likely deficiency, and the Authority and The Generator shall agree upon the nature and timing of the corrective actions.

(6) The T&D Licensee shall, if The Generator's prior year performance on fuel efficiency as shown in the report submitted pursuant to these Rules is outside of the applicable Zone of Acceptability, implement any necessary changes in consumer billings to reflect any applicable reward or penalty.

(7) The T&D Licensee shall, using its forecast of sales figures, determine the amount of any reward or penalty and subject to Authority approval, spread that amount evenly over the balance of the year so that the balance of any reward due to or penalty imposed on the T&D Licensee shall be zero at the end of that year.

(8) A penalty shall only apply if The Generator has failed to implement the agreed upon corrective actions.

(9) Rewards and penalties shall be reflected as a "z factor" on a consumers' bill.

(10) The T&D Licensee shall, upon implementation, establish a tracking account to monitor the balance in an account.

(11) The Generator shall provide the Authority with a report of the projection of the next year's expected Net Fuel Efficiency by 15th November of each year.

(12) The report required under paragraph (11) shall separate the amount required for station usage from station export.

(13) A reward or penalty shall be calculated annually at one thousand dollars for every 0.01 kWh/IG of total annual Net Plant Fuel Efficiency outside the Zone of Acceptability up to a maximum reward or penalty of one hundred thousand dollars per year during the Initial Period.

(14) The EAF Target shall be 81.9 % and the Zone of Acceptability shall be plus or minus 7.5%, or 75.8% to 88.0% in 2011.

(15) The EAF Target for 2011 shall be calculated based on the average of the actual annual total plant EAF for the four years ended 31st December, 2007, 2008, 2009 and 2010.

(16) The Target for calendar years 2012 and 2013 shall be based on the rolling average of the actual performance for the previous five years, respectively, unless revised by the Authority after the Initial Period.

(17) The Generator shall, during the Initial Period, include planned outages in the measure of EAF and in its quarterly reports to the Authority it shall separately provide monthly figures for the elements of the EAF, being planned outages, forced outages and unit seasonal derating outages, as defined by ANSI/IEEE Standard 762-1987(R2002) set out in Schedule 1.

Schedule 1

(18) The Generator shall provide the Authority with a projection of its forecasted EAF for the coming year by 15th November of each year and shall divide this projection into the elements of the EAF, being planned outages, forced outages and unit seasonal derating outages, as defined by ANSI/IEEE Standard 762-1987(R2002), and justify the level of planned outages to the Authority.

(19) A penalty or reward amount of five thousand dollars shall be applied for every 0.2% EAF outside the Zone of Acceptability and for the Initial Period, the reward or penalty shall be limited to one hundred thousand dollars and the maximum reward is achieved at 92.0%, or greater, while a maximum penalty will occur at 71.8% or lower being 20 increments of 0.2% outside the Zone of Acceptability.

(20) The Authority shall monitor The Generator's EAF performance during the year and The Generator shall report to the Authority at the end of each quarter on whether it expects that The Generator will be within the Zone of Acceptability for the entire year.

(21) The Authority and The Generator shall, if any quarterly report indicates a deficiency in EAF for the year or upon the Authority's request, discuss the reasons for such anticipated performance and The Generator shall propose and implement corrective actions, which in its judgment will correct the likely deficiency, and the Authority and The Generator shall agree upon the nature and timing of such corrective actions.

(22) The Generator shall, when EAF for the prior year is known but no later than the end of January in any year, file a report with the Authority indicating whether any reward or penalty is due to The Generator based on the prior year's EAF.

(23) The T&D Licensee shall, subject to Authority approval, in the event that a reward or penalty applies, using it's forecast of sales spread the amount of that reward or penalty evenly over the balance of the year, so that the balance of any reward due to or penalty imposed on the T&D Licensee shall be zero at the end of that calendar year.

(24) A penalty shall only apply if The Generator has failed to implement the agreed upon corrective actions.

(25) Rewards and penalties shall be reflected as a "z factor" on a consumers' bill.

SCHEDULE 1

(Regulations 2 and 7(17))

ANSI/IEEE Std 762-1987(R2002)
(Revision of ANSI/IEEE Std 762, originally issued for trial use in 1980)

IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity

Sponsor
Power Systems Engineering Committee of the IEEE Power Engineering Society

Reaffirmed March 20, 2002
IEEE-SA Standards Board

Approved September 19, 1985
IEEE Standards Board

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American National Standards Institute

IEEE-SA Standards Board
Approved September 19, 1985
Recognized as an
American National Standard (ANSI)

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Secretary, IEEE Standards Board
345 East 47th Street
New York, NY 10017
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Foreword

(This Foreword is not a part of ANSI/IEEE Std 762-1987, IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity.)

Measures of generating unit performance have been defined, recorded, and utilized by the electric power industry for over 40 years. Initially, only a few terms, such as *forced outage rate* and *scheduled outage rate*, were needed. The increased focus on generating unit performance in recent years has caused regulatory agencies and the industry to place a greater emphasis on performance measures.

These contemporary constraints have amplified the difficulties that evolved from having generating unit statistics compiled by different organizations to meet their own specific needs. In the past these difficulties have included the interpretation of data within a given system by an outside agency and the correlation of data among the various systems.

The current problems have made clear the need for a standard to overcome these difficulties by providing terminology and indexes for use in existing data systems or in future systems. This standard is directed toward allowing for a meaningful exchange of electric generating unit performance data while attempting to retain as much of existing systems as possible.

No attempt is made here to standardize or to recommend methodologies or procedures for the collection of unit performance data. Furthermore, no attempt is made here to address the special requirements of electric generating units limited by fuel supplies, resources such as water (hydro), or environmental restrictions. It is expected that the methods used will continue to vary from system to system according to individual needs. What is attempted is to specify certain common terms and indexes that must be obtainable from each data base to provide for a basis of information exchange.

The task force has attempted to keep the list of terms and indexes as brief as possible. Performance cannot be measured by a single parameter, and several indexes are required to indicate the ability of a generating unit to produce power when called upon. The use of any single index to measure the performance of a unit or a class of units is misleading. This requirement has necessitated the inclusion of all of the terms and indexes as given here.

Some indexes are based on period hours. By use of such a common base, simple additive relationships between various indexes result, and the use of period hours gives sets of indexes that sum to 100%, as described in Appendix C. Other indexes are not based on period hours. For example, in the statistic forced outage rate (see 7.16), (service hours forced outage hours) is used as a base because forced outage rate is intended to estimate the probability of forced outage during the times when there is no planned or maintenance outage. For other than base load service, further modifications are needed to estimate this probability correctly. It is the intent of the task force to define sufficient data categories (states, times, capacity levels) so that suitable indexes for all types of units can be calculated.

It should be noted that even the use of all the indexes and terms cannot identify the underlying and sometimes compelling reasons for lost performance.

This standard was prepared by the Power Plant Productivity Definitions Task Force of the Applications of Probability Methods Subcommittee of the Power Systems Engineering Committee, whose members were as follows:

M.P. Bhavaraju, *Chair*

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The task force wishes to dedicate this work to the memory of Veazey M.Cook, a pioneer in the application of generating unit outage data in system planning studies. The format and many of the terms used in this standard can be traced to Veazey Cook's work.

CLAUSE PAGE

An American National Standard

IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity

1. Purpose

This standard is intended to aid the electric power industry in reporting and evaluating electric generating unit reliability, availability, and productivity. It was developed to overcome present difficulties in the interpretation of electric generating unit performance data from various systems and to facilitate comparisons among different systems. The standard should also make possible the future exchange o meaningful data among systems in North America and throughout the world.

2. Scope

This document standardizes terminology and indexes for reporting electric generating unit reliability, availability, and productivity performance measures. A generating unit includes all equipment up to the high-voltage terminal of the generator step-up transformer. Reliability in this standard encompasses measures of the ability of generating units to perform their intended function. Availability measures are concerned with the fraction of time a unit is capable of providing service, and account for outage frequency and duration. Productivity measures are concerned with the total power produced by a plant with respect to its potential power production. Therefore, productivity measures consider magnitude of outage as well as frequency and duration of outage.

NOTE — This standard was developed for application at the unit level; the definitions are applicable below the unit level in most cases. There are some exceptions, however, such as the definition of *in service*, which applies only at the unit level. Because of these exceptions, care should be taken when using this standard below the unit level.

3. Unit States

A unit state is a particular unit condition that is important for purposes of collecting data on performance.

NOTE — The state definitions are related as shown in Fig 1. The transitions between states are described in Appendix B. The correlation between these definitions and those in use by the industry is shown in Appendix A.

3.1 Active

The state in which a unit is in the population of units being reported on.

NOTE — A unit generally enters the active state on its service date.

3.1.1 Available
The state in which a unit is capable of providing service, whether or not it is actually in service and regardless of the capacity level that can be provided.

3.1.1.1 In Service
The state in which a unit is electrically connected to the system.

3.1.1.2 Reserve Shutdown
The state in which a unit is available but not in service.

NOTE — This is sometimes referred to as economy shutdown.

3.1.2 Unavailable
The state in which a unit is not capable of operation because of operational or equipment failures, external restrictions, testing, work being performed, or some adverse condition. The unavailable state persists until the unit is made available for operation, either by being synchronized to the system (in-service state) or by being placed in the reserve shutdown state.

3.1.2.1 Planned Outage
The state in which a unit is unavailable due to inspection, testing, nuclear refueling, or overhaul. A planned outage is scheduled well in advance.

3.1.2.1.1 Basic Planned Outage
The planned outage state that is originally scheduled and of a predetermined duration.

3.1.2.1.2 Extended Planned Outage
The planned outage state that is the extension of the basic planned outage beyond its predetermined duration.

NOTE — Extended planned outage applies only when planned work exceeds predetermined duration. The extension, due to a condition discovered during the planned outage that has forced the extension of the planned outage, is to be classified as Class 1 unplanned outage (see 3.1.2.2.2). Startup failure would result in Class 0 unplanned outage (see 3.1.2.2.1).

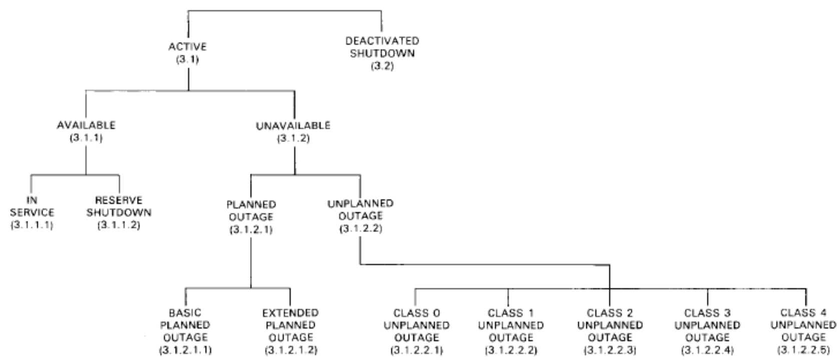

Figure 1—Relation Between Unit States

3.1.2.2 Unplanned Outage
The state in which a unit is unavailable but is not in the planned outage state.

NOTES:

1 — When an unplanned outage is initiated, the outage is to be classified according to one of five classes, as defined in 3.1.2.2.1 through 3.1.2.2.5. Unplanned outage Class 0 applies to a start-up failure and Class 1 applies to a condition requiring immediate outage. Also, unplanned outage starts when planned outage ends but is extended due to unplanned work. Classes 2, 3, and 4 apply to outages where some delay is possible in time of removal of the unit from service. The class (2, 3, or 4) of outage is to be determined by the amount of delay that can be exercised in the time of removal of the unit. The class of outageis not made more urgent if the time of removal is advanced due to favorable conditions of system reserves or availability of replacement capacity for the predicted duration of the outage. However, outage starts when the unit is removed from service or is declared unavailable when it is not in service.

2 — During the time the unit is in the unplanned outage state, the outage class is determined by the outage class that initiates the state.

3 — In some cases, the opportunity exists during unplanned outages to perform some of the repairs or maintenance that would have been performed during the next planned outage. If the additional work extends the outage beyond that required for the unplanned outage, the remaining outage should be reported as a planned outage.

4 — Unlike planned outages, unplanned outages do not have a fixed duration that can be estimated each year.

3.1.2.2.1 Class 0 Unplanned Outage (Starting Failure)
An outage that results from the unsuccessful attempt to place the unit in service (see 3.1.3.1).

3.1.2.2.2 Class 1 Unplanned Outage (Immediate)
An outage that requires immediate removal from the existing state.

NOTE — A Class 1 unplanned outage can be initiated from either the in-service or reserve shutdown states. A Class 1 unplanned outage can also be initiated from the planned outage state. See Note in 3.1.2.1.2.

3.1.2.2.3 Class 2 Unplanned Outage (Delayed)
An outage that does not require immediate removal from the in-service state but requires removal within 6 h.

3.1.2.2.4 Class 3 Unplanned Outage (Postponed)
An outage that can be postponed beyond 6 h but requires that a unit be removed from the in-service state before the end of the next weekend.

NOTE — Classes 2 and 3 can only be initiated from the inservice state.

3.1.2.2.5 Class 4 Unplanned Outage (Deferred)
An outage that will allow a unit outage to be deferred beyond the end of the next weekend but requires that a unit be removed from the available state before the next planned outage.

3.1.2.3 Repair Urgency
When a planned or unplanned outage is initiated, the urgency with which repair activities are carried out is classified according to one of three classes as defined in 3.1.2.3.1 through 3.1.2.3.3.

3.1.2.3.1 Maximum Effort
Repairs were accomplished in the shortest possible time.

3.1.2.3.2 Normal Effort
Repairs were carried out with normal repair crews working normal shifts.

3.1.2.3.3 Low-Priority Effort
Repairs were carried out with less than a normal effort.

3.1.3 Starting Attempt
The action to bring a unit from shutdown to the in-service state. Repeated initiations of the starting sequence without accomplishing corrective repairs are counted as a single attempt.

3.1.3.1 Starting Failure
The inability to bring a unit from some unavailable state or reserve shutdown state to the in-service state within a specified period. The specified period may be different for individual units. Repeated failures within the specified starting period are to be counted as a single starting failure.

3.1.3.2 Starting Success
The occurrence of bringing a unit from some unavailable state or the reserve shutdown state to the in-service state within a specified period. The specified period may be different for individual units.

3.2 Deactivated Shutdown
The state in which a unit is unavailable for service for an extended period of time because of its removal for economy or reasons not related to the equipment. Under this condition, a unit generally requires weeks of preparation to make it available.

4. Capacity Terms
Terms that involve capacity can be expressed as gross or net quantities.

NOTE — The capacity definitions are related as shown in Fig 2. The correlation between the capacity-derating definitions in this section and partial-outage definitions in use by industry is shown in Appendix A.

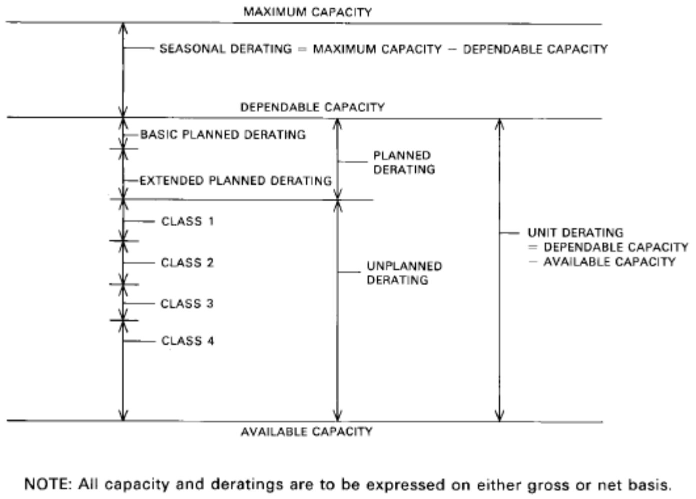

Figure 2—Unit Capacity Levels

4.1 Maximum Capacity (MC)

The maximum capacity that a unit can sustain over a specified period of time. The maximum capacity can be expressed as gross maximum capacity (GMC) or net maximum capacity (NMC). To establish this capacity, formal demonstration is required. The test should be repeated periodically. This demonstrated capacity level shall be corrected to generating conditions for which there should be minimum ambient restriction. When a demonstration test has not been conducted, the estimated maximum capacity of the unit shall be used.

4.2 Dependable Capacity

The maximum capacity, modified for ambient limitations for a specified period of time, such as a month or a season.

4.3 Available Capacity

The dependable capacity, modified for equipment limitation at any time.

4.4 Seasonal Derating

The difference between maximum capacity and dependable capacity.

4.5 Unit Derating

The difference between dependable capacity and available capacity.

4.6 Planned Derating
That portion of the unit derating that is scheduled well in advance.

4.6.1 Basic Planned Derating
The planned derating that is originally scheduled and of predetermined duration.

4.6.2 Extended Planned Derating
The planned derating that is the extension of the basic planned derating beyond its predetermined duration.

4.7 Unplanned Derating
That portion of the unit derating that is not a planned derating. Unplanned derating events are classified according to the urgency with which the derating needs to be initiated, as defined in 4.7.1 through 4.7.4.

4.7.1 Unplanned Derating, Class 1 (Immediate)
A derating that requires an immediate action for the reduction of capacity.

4.7.2 Unplanned Derating, Class 2 (Delayed)
A derating that does not require an immediate reduction of capacity, but requires a reduction of capacity within 6 h.

4.7.3 Unplanned Derating, Class 3 (Postponed)
A derating that can be postponed beyond 6 h, but requires a reduction of capacity before the end of the next weekend.

4.7.4 Unplanned Derating, Class 4 (Deferred)
A derating that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

4.8 Installed Nameplate Capacity
The full-load continuous gross capacity of a unit under specified conditions, as calculated from the electric generator nameplate based on the rated power factor.

NOTE — The nameplate rating of the electric generator may not be indicative of the unit maximum or dependable capacity, since some other item or equipment (such as the turbine) may limit unit output.

5. Time Designations and Dates

NOTE — The time spent in the various unit states defined in Section 3 is defined in 5.1 through 5.10. See Fig 3. In 5.11 through 5.16, the time a unit was subject to the various categories of unit derating defined in Section 4. is defined. Derated time is accumulated only during the available, inservice, and reserve shutdown states.

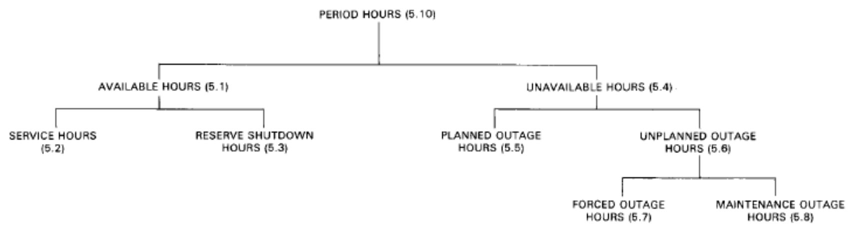

Figure 3—Time Spent in Various Unit States

5.1 Available Hours (AH)
The number of hours a unit was in the available state.

NOTE — Available hours is the sum of service hours and reserve shutdown hours, or may be computed from period hours minus unavailable hours (see 5.4).

5.2 Service Hours (SH)
The number of hours a unit was in the in-service state.

5.3 Reserve Shutdown Hours (RSH)
The number of hours a unit was in the reserve shutdown state.

5.4 Unavailable Hours (UH)
The number of hours a unit was in the unavailable state.

NOTE — Unavailable hours are the sum of planned outage hours and unplanned outage hours, or the sum of planned outage hours, forced outage hours, and maintenance outage hours.

5.5 Planned Outage Hours (POH)
The number of hours a unit was in the basic or extended planned outage state.

5.6 Unplanned Outage Hours (UOH)
The number of hours a unit was in a Class 0, 1, 2, 3, or 4 unplanned outage state.

5.7 Forced Outage Hours (FOH)
The number of hours a unit was in a Class 0, 1, 2, or 3 unplanned outage state.

5.8 Maintenance Outage Hours (MOH)
The number of hours a unit was in a Class 4 unplanned outage state.

5.9 Deactivated Shutdown Hours (DSH)
The number of hours a unit was in the deactivated shutdown state.

5.10 Period Hours (PH)
The number of hours a unit was in the active state.

5.11 Unit Derated Hours (UNDH)
The available hours during which a unit derating was in effect.

5.11.1 In-Service Unit Derated Hours (IUNDH)
The in-service hours during which a unit derating was in effect.

5.11.2 Reserve Shutdown Unit Derated Hours (RSUNDH)
The reserve shutdown hours during which a unit derating was in effect.

5.12 Planned Derated Hours (PDH)
The available hours during which a basic or extended planned derating was in effect.

5.12.1 In Service PlAnned Derated Hours (IPDH)
The in-service hours during which a basic or extended planned derating was in effect.

5.12.2 Reserve Shutdown Planned Derated Hours (RSPDH)
The reserve shutdown hours during which a basic or extended planned derating was in effect.

5.13 Unplanned Derated Hours (UDH)
The available hours during which an unplanned derating was in effect.

5.13.1 In-Service Unplanned Derated Hours (IUDH)
The in-service hours during which an unplanned derating was in effect.

5.13.2 Reserve Shutdown Unplanned Derated Hours (RSUDH)
The reserve shutdown hours during which an unplanned derating was in effect.

5.14 Forced Derated Hours (FDH)
The available hours during which a Class 1, 2, or 3 unplanned derating was in effect.

5.14.1 In-Service Forced Derated Hours (IFDH)
The in-service hours during which a Class 1, 2, or 3 unplanned derating was in effect.

5.14.2 Reserve Shutdown Forced Derated Hours (RSFDH)

The reserve shutdown hours during which a Class 1, 2, or 3 unplanned derating was in effect.

5.15 Maintenance Derated Hours (MDH)

The available hours during which a Class 4 unplanned derating was in effect.

5.15.1 In-Service Maintenance Derated Hours (IMDH)

The in-service hours during which a Class 4 unplanned derating was in effect.

5.15.2 Reserve Shutdown Maintenance Derated Hours (RSMDH)

The reserve shutdown hours during which a Class 4 unplanned derating was in effect.

5.16 Seasonal Derated Hours (SDH)

The available hours during which a seasonal derating was in effect.

5.17 Equivalent Hours (E)

The number of hours a unit was in a time category involving unit derating, expressed as equivalent hours of full outage at maximum capacity. Both unit derating and maximum capacity shall be expressed on a consistent basis, gross or net. Equivalent hours can be calculated for each of the time categories in 5.11through 5.16. The symbol designation for the equivalent hours is formed by adding an E in front of the symbol for the corresponding time designation (for example, equivalent unit derated hours is designated EUNDH). Equivalent hours can be calculated from the following equation:

$$E(\ ) = \frac{\Sigma D(\ )_i T_i}{\text{MC}}$$

where

$E(\ )$ = equivalent hours in the time category represented by parentheses, which can be any one of the time categories in 5.11 through 5.16

$D(\ )_i$ = the derating for the time category shown in parentheses, after the ith change in either available capacity (unit deratings) or dependable capacity (seasonal deratings)

> NOTE — In order to apportion equivalent hours among the various time categories, appropriate ground rules shall be established in the reporting system so that after each

change in either available capacity or dependable capacity, the sum of all subcategories of unit derating is equal to the unit derating.

T_i = the number of hours accumulated in the time category of interest between the ith and the (i + 1)th change in either available capacity (unit deratings) or dependable capacity (seasonal deratings)

MC = maximum capacity

5.18 Deactivation Date
The date a unit was placed into the deactivated shutdown state.

5.19 Reactivation Date
The date a unit was returned to the active state from the deactivated shutdown state.

6. Energy Terms
Similar to capacity terms, energy terms can be expressed as gross or net quantities.

6.1 Actual Generation (AAG)
The energy that was generated by a unit in a given period. Actual generation can be expressed as gross actual generation (GAAG) or net actual generation (NAAG).

6.2 Maximum Generation (MG)
The energy that could have been produced by a unit in a given period of time if operated continuously at maximum capacity. Maximum generation can be expressed as gross maximum generation (GMG) or net maximum generation (NMG).

MG = period hours · maximum capacity = PH · MC

GMG = PH · GMC
NMG = PH · NMC

6.3 Available Generation (AG)
The energy that could have been generated by a unit in a given period if operated continuously at its available capacity.

6.4 Unavailable Generation (UG)
The difference between the energy that would have been generated if operating continuously at dependable capacity and the energy that would have been

generated if operating continuously at available capacity. This is the energy that could not be generated by a unit due to planned and unplanned outages and unit deratings.

UG = (planned outage hours + unplanned outage hours + equivalent unit derated hours) · maximum capacity = (POH + UOH + EUNDH) · MC

6.5 Seasonal Unavailable Generation (SUG)

The difference between the energy that would have been generated if operating continuously at maximum capacity and the energy that would have been generated if operating continuously at dependable capacity, calculated only during the time the unit was in the available state.

SUG = equivalent seasonal derated hours · maximum capacity = ESDH · MC

6.6 Reserve Generation (RG)

The energy that a unit could have produced in a given period but did not, because it was not required by the system. This is the difference between available generation and actual generation.

6.7 Derated Generation (DG)

The generation that was not available due to unit deratings.

DG = equivalent unit derated hours · maximum capacity = EUNDH · MC

7. Performance Indexes

Appendix C discusses the relationships among the performance indexes that are based on period hours.

NOTE — All per unit performance indexes are expressed in percentage.

7.1 Planned Outage Factor (POF)

$$\mathrm{POF} = \frac{\text{planned outage hours}}{\text{period hours}} \cdot 100 = \frac{\mathrm{POH}}{\mathrm{PH}} \cdot 100$$

7.2 Unplanned Outage Factor (UOF)

$$\mathrm{UOF} = \frac{\text{unplanned outage hours}}{\text{period hours}} \cdot 100 = \frac{\mathrm{UOH}}{\mathrm{PH}} \cdot 100$$

7.3 Forced Outage Factor (FOF)

$$\mathrm{FOF} = \frac{\text{forced outage hours}}{\text{period hours}} \cdot 100$$
$$= \frac{\mathrm{FOH}}{\mathrm{PH}} \cdot 100$$

7.4 Maintenance Outage Factor (MOF)

$$\mathrm{MOF} = \frac{\text{maintenance outage hours}}{\text{period hours}} \cdot 100$$
$$= \frac{\mathrm{MOH}}{\mathrm{PH}} \cdot 100$$

7.5 Unavailability Factor (UF)

$$\mathrm{UF} = \frac{\text{unavailable hours}}{\text{period hours}} \cdot 100$$
$$= \frac{\mathrm{UH}}{\mathrm{PH}} .100$$
$$= \frac{\mathrm{POH} + \mathrm{MOH} + \mathrm{FOH}}{\mathrm{PH}} \cdot 100$$
$$= \frac{\mathrm{POH} + \mathrm{UOH}}{\mathrm{PH}} \cdot 100$$

7.6 Availability Factor (AF)

$$\mathrm{AF} = \frac{\text{available hours}}{\text{period hours}} .100$$
$$= \frac{\mathrm{AH}}{\mathrm{PH}} .100$$

7.7 Service Factor (SF)

$$\mathrm{SF} = \frac{\text{service hours}}{\text{period hours}} .100$$
$$= \frac{\mathrm{SH}}{\mathrm{PH}} .100$$

7.8 Seasonal Derating Factor (SDF)

The fraction of maximum generation that could not be produced due to seasonal deratings:

$$\mathrm{SDF} = \frac{\text{seasonal unavailable generation}}{\text{maximum generation}} .100$$
$$= \frac{\mathrm{SUG}}{\mathrm{MG}} .100$$
$$= \frac{\mathrm{ESDH}}{\mathrm{PH}} .100$$

7.9 Unit Derating Factor (UDF)

The fraction of maximum generation that could not be produced due to unit deratings:

$$UDF = \frac{\text{unit derated generation}}{\text{maximum generation}}.100$$
$$= \frac{DG}{MG}.100$$
$$= \frac{EUNDH}{PH}.100$$

7.10 Equivalent Unavailability Factor (EUF)

The fraction of maximum generation that could not be produced due to unit deratings and planned and unplanned outages:

$$EUF = \frac{\text{unit unavailable generation}}{\text{maximum generation}}.100$$
$$= \frac{UG}{MG}.100$$
$$= \frac{POH + MOH + FOH + EUNDH}{PH}.100$$

7.11 Equivalent Availability Factor (EAF)

The fraction of maximum generation that could be provided if limited only by outages and deratings:

$$EAF = \frac{\text{available generation}}{\text{maximum generation}}.100$$
$$= \frac{AG}{MG}.100$$
$$= \frac{AH - (EUNDH + ESDH)}{PH}.100$$

7.12 Gross Capacity Factor (GCF)

$$GCF = \frac{\text{gross actual generation}}{\text{gross maximum generation}}.100$$
$$= \frac{GAAG}{GMG}.100$$

7.13 Net Capacity Factor (NCF)

$$NCF = \frac{\text{net actual generation}}{\text{net maximum generation}}.100$$
$$= \frac{NAAG}{NMG}.100$$

NOTE — Net capacity factor calculated using this equation can be negative during a period when the unit is shutdown. For meaningful pooling of data on several units, net capacity factor can be defined to be zero when the unit is shutdown.

7.14 Gross Output Factor (GOF)

$$GOF = \frac{\text{gross actual generation}}{\text{service hours . gross maximum capacity}}.100$$
$$= \frac{GAAG}{SH . GMC}.100$$

7.15 Net Output Factor (NOF)

$$NOF = \frac{\text{net actual generation}}{\text{service hours . net maximum capacity}} .100$$

$$= \frac{NAAG}{SH . NMC} .100$$

7.16 Forced Outage Rate (FOR)

$$FOR = \frac{\text{forced outage hours}}{\text{forced outage hours} + \text{service hours}} .100$$

$$= = \frac{FOH}{FOH + SH} .100$$

7.17 Equivalent Forced Outage Rate (EFOR)

$$EFOR = \frac{\text{forced outage hours} + \text{sum of equivalent forced derated hours}}{\text{service hours} + \text{forced outage hours} + \text{sum of equivalent reserve shutdown forced derated hours}} .100$$

$$= \frac{FOH + EFDH}{SH + FOH + ERSFDH} .100$$

7.18 Mean Service Time to Outage

7.18.1 Mean Service Time to Forced Outage (MSTFO)

$$MSTFO = \frac{\text{service hours}}{\text{number of Class 1, 2, and 3 unplanned outages that occur fro}}$$

7.18.2 Mean Service Time to Maintenance Outage (MSTMO)

$$MSTMO = \frac{\text{service hours}}{\text{number of Class 4 unplanned outages that occur from in-servic}}$$

7.18.3 Mean Service Time to Planned Outage (MSTPO)

$$MSTPO = \frac{\text{service hours}}{\text{number of planned outages that occur from in-service state}}$$

NOTE — In 7.18.1, only forced outages occurring from in-service state are considered. The name for the index could be "mean service time to *in-service* forced outage." However, for simplicity in-service is not included in the name. This note is also applicable to 7.18.2 and 7.18.3.

Indexes similar to 7.18.1, 7.18.2, and 7.18.3 can also be calculated for outages that occur during reserve shutdown state.

7.19 Mean Outage Duration

7.19.1 Mean Forced Outage Duration (MFOD)

$$MFOD = \frac{\text{forced outage hours}}{\text{numbers of Class 1, 2, and 3 unplanned outages}}$$

7.19.2 Mean Maintenance Outage Duration (MMOD)

$$MMOD = \frac{\text{maintenance outage hours}}{\text{number of Class 4 unplanned outages}}$$

7.19.3 Mean Planned Outage Duration (MPOD)

$$\text{MPOD} = \frac{\text{planned outage hours}}{\text{number of planned outages}}$$

NOTE — Similar to 7.18, outage hours and number of outages in 7.19 include outages that occur from in-service state only.

7.20 Starting Reliability (SR)

$$\text{SR} = \frac{\text{number of starting successes}}{[\text{number of starting successes} + \text{number of starting failures}]} \cdot 100$$

7.21 Cycling Rate (CR)

$$\text{CR} = \frac{\text{starting successes}}{\text{service hours}}$$

Annex A

Correlation Between Unit State and Capacity Derating Definitions in This Standard and Those Formerly Used by the Industry

(Informative)

(These Appendixes are not a part of ANSI/IEEE Std 762-1987, EEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity.)

This standard	Former Industry Definitions
Available	No change
In service	No change
Reserve shutdown	No change
Unavailable	No change
Basic planned outage	No change
Extended planned outage	Not defined
Unplanned outage	Not defined
Class 0 (starting failure)	
Class 1 (immediate)	
Class 2 (less than 6 h) delayed	Forced outage
Class 3 (more than 6 h; before the end of the next weekend) postponed	
Class 4 (after the next weekend before the next planned outage) deferred	Maintenance outage
Deactivated shutdown	Not defined
Seasonal derating	Not defined
Unit derating	Not defined
Unplanned derating	Not defined
Class 1 (immediate)	
Class 2 (less than 6 h) delayed	Forced partial outage
Class 3 (more than 6 hr; before the end of the next weekend) postponed	
Class 4 (after the next weekend before the next planned outage) maintenance derating	Scheduled partial outage
Planned derating (basic or extended)	

Annex B

Transitions Between States

(Informative)

Section 3 defines three primary unit states:
1) Available
2) Unavailable
3) Deactivated shutdown

These three states are mutually exclusive and exhaustive. A unit will be in exactly one of these states at all times. Thus, these states divide calendar time into nonoverlapping segments. The available and unavailable states are each divided into additional, mutually exclusive states. The available state is divided into in-service and reserve shutdown states, and the unavailable state is divided into planned and unplanned outage states. These four secondary states, together with the deactivated shutdown state, also form a mutually exclusive and exhaustive set. Finally, the planned outage state is divided into basic and extended planned outage states. Also, the unplanned outage state is divided into five outage classes, according to the urgency with which the outage is initiated. Like the other states, the unplanned outage classes are defined to be mutually exclusive. The unit state structure can also be described by starting with the lowest level states. Thus, there are ten basic states:

1) In service
2) Reserve shutdown
3) Basic planned outage
4) Extended planned outage
5) Class 0 unplanned outage
6) Class 1 unplanned outage
7) Class 2 unplanned outage
8) Class 3 unplanned outage
9) Class 4 unplanned outage
10) Deactivated shutdown

These basic states are defined to be mutually exclusive and exhaustive. By grouping various subsets of the basic states together, each of the secondary and primary states can be formed.

Once a unit is in a state, it remains in that state until a transition event occurs that causes the unit to move to another state. The possible transition events can be shown by use of a state transition matrix. Figure B.1 shows a state transition matrix for the ten basic states. The left side of the matrix shows the possible unit states before a transition event. The top row of the matrix shows the (same) possible unit states after a transition event. Thus, each (nondiagonal) element of the matrix can be used to describe a transition event from the state on the left to the top state. Figure B.1 shows the transition events that are possible according to the definitions in Section 3. The elements denoted by "x" are not possible.

By looking on a particular row of Fig B.1, the possible transition events that can terminate a state can be seen. By looking at a particular column of Fig the possible transition events that can initiate a state can be seen.

Detailed definitions for the transition events in Fig have not been included in this standard. However, in actual reporting generating unit performance, it is the transition event occurrence times that are in fact reported, from which the state duration times are then calculated. Therefore, the reporting instructions that implement the collection of unit performance data should give careful consideration to defining precisely and clearly the exact point in time at which the various transitions take place.

STATE BEFORE TRANSITION	STATE AFTER TRANSITION									
	IN SERVICE	RESERVE SHUTDOWN	BASIC PLANNED OUTAGE	EXTENDED PLANNED OUTAGE	CLASS 0 UNPLANNED OUTAGE	CLASS 1 UNPLANNED OUTAGE	CLASS 2 UNPLANNED OUTAGE	CLASS 3 UNPLANNED OUTAGE	CLASS 4 UNPLANNED OUTAGE	DEACTIVATED SHUTDOWN
IN SERVICE		SHUTDOWN FOR ECONOMY	SHUTDOWN FOR PLANNED OUTAGE	X	X	SHUTDOWN FOR UNPLANNED OUTAGE: IMMEDIATE	DELAYED	POSTPONED	DEFERRED	SHUTDOWN TO DEACTIVATE
RESERVE SHUTDOWN	STARTING SUCCESS		BEGIN PLANNED OUTAGE	X	STARTING FAILURE	COMPONENT FAILURE FOUND DURING SHUTDOWN	X	X	BEGIN MAINTENANCE OUTAGE	BEGIN DEACTIVATION
BASIC PLANNED OUTAGE	STARTING SUCCESS	END PLANNED OUTAGE		EXTEND PLANNED OUTAGE	STARTING FAILURE	COMPONENT FAILURE FOUND DURING SHUTDOWN	X	X	BEGIN MAINTENANCE OUTAGE	BEGIN DEACTIVATION
EXTENDED PLANNED OUTAGE	STARTING SUCCESS	END EXTENDED PLANNED OUTAGE	X		STARTING FAILURE	COMPONENT FAILURE FOUND DURING SHUTDOWN	X	X	BEGIN MAINTENANCE OUTAGE	BEGIN DEACTIVATION
CLASS 0 UNPLANNED OUTAGE	STARTING SUCCESS	END CLASS 0 OUTAGE	EXTEND FOR PLANNED WORK	X		X	X	X	X	BEGIN DEACTIVATION
CLASS 1 UNPLANNED OUTAGE	STARTING SUCCESS	END CLASS 1 OUTAGE	EXTEND FOR PLANNED WORK	X	STARTING FAILURE		X	X	X	BEGIN DEACTIVATION
CLASS 2 UNPLANNED OUTAGE	STARTING SUCCESS	END CLASS 2 OUTAGE	EXTEND FOR PLANNED WORK	X	STARTING FAILURE	X		X	X	BEGIN DEACTIVATION
CLASS 3 UNPLANNED OUTAGE	STARTING SUCCESS	END CLASS 3 OUTAGE	EXTEND FOR PLANNED WORK	X	STARTING FAILURE	X	X		X	BEGIN DEACTIVATION
CLASS 4 UNPLANNED OUTAGE	STARTING SUCESS	END CLASS 4 OUTAGE	EXTEND FOR PLANNED WORK	X	STARTING FAILURE	X	X	X		BEGIN DEACTIVATION
DEACTIVATED SHUTDOWN	STARTING SUCCESS	END DEACTIVATED SHUTDOWN	X	X	STARTING FAILURE	X	X	X	X	

"X" indicates that the transfer is not possible.

Figure B.1—State Transition Matrix

Annex C

Relationships Between Period-Hour-Based Performance Indexes

(Informative)

For purposes of measuring and improving the performance of individual generating units, it is common to emphasize measures that are based on period hours. The performance indexes in Section 7 provide a unified set of period-hourbased indexes (called factors), as follows:

AF = availability factor
UF = unavailability factor
EAF = equivalent availability factor
EUF = equivalent unavailability factor
FOF = forced outage factor
MOF = maintenance outage factor
UOF = unplanned outage factor = FOF + MOF

POF = planned outage factor
SDF = seasonal derating factor
UDF = unit derating factor

These indexes are unified in the sense that they are related in the following ways:

$$EAF = AF - (UDF + SDF) \tag{C1}$$

$$EUF = UF + UDF \tag{C2}$$

$$AF + UF = 100 \tag{C3}$$

$$EAF + EUF + SDF = 100 \tag{C4}$$

$$UF = POF + UOF \tag{C5}$$

$$EUF = POF + UOF + UDF \tag{C6}$$

$$\begin{aligned} &EAF + POF + UOF + UDF \\ &\quad + SDF = 100 \end{aligned} \tag{C7}$$

Equation C1 shows that equivalent availability can be obtained by subtracting the unit derating factor and the seasonal derating factor from the availability factor.

Equation C2 shows that equivalent unavailability can be obtained by adding the unit derating factor, but not the seasonal derating factor, to the unavailability factor.

Equation C3 shows that the availability and unavailability factors add to 100%.

Equation C4 shows that the equivalent availability, equivalent unavailability, and seasonal derating factor also add to 100%. However, equivalent availability and equivalent unavailability alone do not, in general, add to 100%, because this sum does not include the effect of seasonal deratings.

Equation C5 shows that the unavailability factor is the sum of the planned and unplanned outage factors (unplanned outage factor is the sum of maintenance outage factor and forced outage factor).

Substituting Eq C5 into Eq C2 produces Eq C6, which shows that equivalent unavailability is the sum of the planned and unplanned outage factors and the unit derating factor.

Substituting Eq C6 into Eq C4 produces Eq C7. This last equation shows that there are four recognized sources of energy loss: planned outages (full), unplanned outages (full), unit deratings, and seasonal deratings. Each energy loss is represented by a separate index: POF, UOF, UDF, and SDF, respectively. These indexes are defined in such a way as to be additive. Therefore, the total per unit energy loss is the sum of the four indexes, and the remaining per unit energy not lost is called equivalent availability factor (EAF).

In order for the four energy loss indexes to be additive, as in Eq C7, it is necessary that the capacity loss due to each source be separated. This means, for example, that a unit cannot simultaneously be subject to full outage and unit derating.

Similarly, a unit cannot simultaneously be subject to both seasonal derating and full outage. In order to achieve nonoverlapping energy definitions, the task force agreed to assign full (maximum) unit capacity to the full outage state. This means that both unit deratings and seasonal deratings are considered to end when a full outage starts, as far as the calculation of the unit derating factor (UDF) and the seasonal derating factor (SDF) are concerned.

In order to further illustrate the relationship between the period-hour-based performance indexes, Fig C1 shows capacity versus time diagram (all capacity values must be either gross or net). The total height of the diagram is maximum capacity (MC), and the total width of the diagram is period hours (PH). Thus, the total area *Y* of the diagram is

$$Y = MC \cdot PH$$

This is the total megawatthour (MWh) of energy that could have been generated during the period if operating continuously at MC.

The area *Y* is divided into several vertical segments by the various time designations in Section 5. The vertical segments involving available hours are further divided into sections to show the energy associated with seasonal derating, unit derating, discretionary reduction, and actual generation. All of the performance factors in Section 7 that are based on period hours can be expressed as simple ratios of the areas in Fig C.1 as follows:

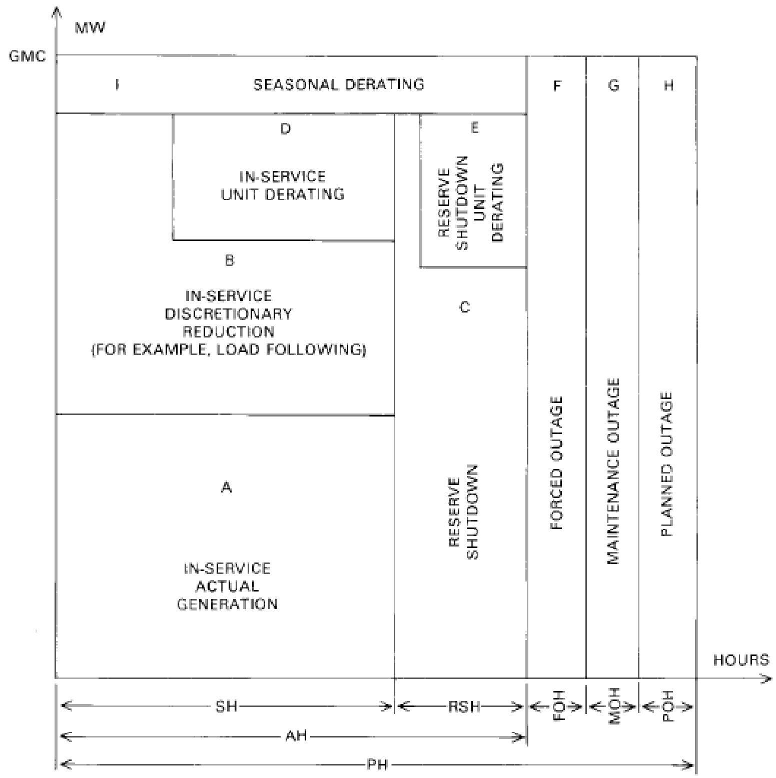

Figure C.1—Relation Between Time and Energy Terms

Time Indexes

$$\text{FOF} = \frac{F}{Y} \cdot 100$$

$$\text{MOF} = \frac{G}{Y} \cdot 100$$

$$\text{UOF} = \text{FOF} + \text{MOF} = \frac{F+G}{Y} \cdot 100$$

$$\text{POF} = \frac{H}{Y} \cdot 100$$

$$\text{UF} = \frac{F+G+H}{Y} \cdot 100$$

$$\text{AF} = \frac{A+B+C+D+E+I}{Y} \cdot 100$$

Energy Indexes

$$\text{UDF} = \frac{D+E}{Y} \cdot 1000$$

$$\text{EAF} = \frac{A+B+C}{Y} \cdot 100$$

$$\text{EUF} = \frac{D+E+F+G+H}{Y} \cdot 100$$

$$\text{SDF} = \frac{I}{Y} \cdot 100$$

$$\text{Capacity Factor} = \frac{A}{Y} \cdot 100$$

NOTE — Capacity factor is GCF or NCF depending on gross or net basis used for capacity.

Using the areas in Fig C.1, a hierarchy of capacity limitation factors can be developed as follows:

$$\text{AF} = \frac{A+B+C+D+E+I}{Y} \cdot 100$$

= average fraction of maximum capacity available, as limited only by full outages (exclude only areas *F, G, H*)

$$\text{EAF} = \frac{A+B+C}{Y} \cdot 100$$

= average fraction of maximum capacity available, as limited by full outages, as well as by unit and seasonal deratings (exclude also areas *D, E,* and *I)*

$$\text{Capacity Factor} = \frac{A}{Y} \cdot 100$$

= average fraction of maximum capacity actually generated (exclude also areas *B* and *C)*

Annex D

Glossary of Terms and Abbreviations

(Informative)

Abbreviation	Reference	Term
AAG	6.1	Actual Generation
AF	7.6	Availability Factor
AG	6.3	Available Generation
AH	5.1	Available Hours
CR	7.21	Cycling Rate
DG	6.7	Derated Generation
DSH	5.9	Deactivated Shutdown Hours
E	5.17	Equivalent Hours
EAF	7.11	Equivalent Availability Factor
EFOR	7.17	Equivalent Forced Outage Rate
EUF	7.10	Equivalent Unavailability Factor
FDH	5.14	Forced Derated Hours
FOF	7.3	Forced Outage Factor
FOH	5.7	Forced Outage Hours
FOR	7.16	Forced Outage Rate
GAAG	6.1	Gross Actual Generation
GCF	7.12	Gross Capacity Factor
GMC	4.1	Gross Maximum Capacity
GMG	6.2	Gross Maximum Generation
GOF	7.14	Gross Output Factor
IFDH	5.14.1	In-Service Forced Derated Hours
IMDH	5.15.1	In-Service Maintenance Derated Hours
IPDH	5.12.1	In-Service Planned Derated Hours
IUDH	5.13.1	In-Service Unplanned Derated Hours
IUNDH	5.11.1	In-Service Unit Derated Hours
MC	4.1	Maximum Capacity
MDH	5.15	Maintenance Derated Hours
MFOD	7.19.1	Mean Forced Outage Duration
MG	6.2	Maximum Generation
MMOD	7.19.2	Mean Maintenance Outage Duration
MOF	7.4	Maintenance Outage Factor
MOH	5.8	Maintenance Outage Hours
MPOD	7.19.3	Mean Planned Outage Duration
MSTFO	7.18.1	Mean Service Time to Forced Outage
MSTMO	7.18.2	Mean Service Time to Maintenance Outage
MSTPO	7.18.3	Mean Service Time to Planned Outage
NAAG	6.1	Net Actual Generation
NCF	7.13	Net Capacity Factor
NMC	4.1	Net Maximum Capacity
NMG	6.2	Net Maximum Generation
NOF	7.15	Net Output Factor

Abbreviation	Reference	Term
PDH	5.12	Planned Derated Hours
PH	5.10	Period Hours
POF	7.1	Planned Outage Factor
POH	5.5	Planned Outage Hours
RG	6.6	Reserve Generation
RSFDH	5.14.2	Reserve Shutdown Forced Derated Hours
RSH	5.3	Reserve Shutdown Hours
RSMDH	5.15.2	Reserve Shutdown Maintenance Derated Hours
RSPDH	5.12.2	Reserve Shutdown Planned Derated Hours
RSUDH	5.13.2	Reserve Shutdown Unplanned Derated Hours
RSUNDH	5.11.2	Reserve Shutdown Unit Derated Hours
SDF	7.8	Seasonal Derating Factor
SDH	5.16	Seasonal Derated Hours
SF	7.7	Service Factor
SH	5.2	Service Hours
SR	7.20	Starting Reliability
SUG	6.5	Seasonal Unavailable Generation
UDF	7.9	Unit Derating Factor
UDH	5.13	Unplanned Derated Hours
UF	7.5	Unavailability Factor
UG	6.4	Unavailable Generation
UH	5.4	Unavailable Hours
UNDH	5.11	Unit Derated Hours
UOF	7.2	Unplanned Outage Factor
UOH	5.6	Unplanned Outage Hours

Word Abbreviations

Abbreviation	Word	Abbreviation	Word
A	Availability, available	O	Outage, output
C	Capacity	P	Period, planned
D	Deactivated shutdown,	R	Rate, reliability
	dependable, duration,	RS	Reserve shutdown
	derated, derating	S	Seasonal, service, starting
E	Equivalent	T	Time, to
F	Factor, forced	U	Unavailability, unavailable, unplanned
G	Generation, gross		
H	Hours	AA	Actual
I	In-service	UN	Unit
M	Maximum, mean, maintenance	Y	Years
N	Net	0, 1, 2, 3, 4	Outage postponability class

SCHEDULE 2

(Regulation 5(2))

1366TM

IEEE Guide for Electric Power Distribution Reliability Indices

IEEE Power Engineering Society

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Distribution Reliability Indices

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Pages 28–30 of the June 2001, Edison Electric Institute 2000 Reliability Report.

Abstract: Distribution reliability indices and factors that affect their calculations are defined in this guide. The indices are intended to apply to distribution systems, substations, circuits, and defined regions.
Keywords: circuits, distribution reliability indices, distribution systems, electric power, reliability indices

Introduction

(This introduction is not part of IEEE Std 1366-2003, IEEE Guide for Electric Power Distribution Reliability Indices.)

This Guide has been updated to clarify existing definitions and to introduce a statistically based definition for classification of major event days. The working group created a methodology, 2.5 Beta Method, for determination of major event days. Once days are classified as normal or major event days, appropriate analysis and reporting can be conducted. After this document is balloted, the working group will continue to investigate the major event definition by reviewing catastrophic events and days with zero events to determine if enhancements are warranted.

Patents

Attention is called to the possibility that implementation of this standard may require use of subject matter covered by patent rights. By publication of this standard, no position is taken with respect to the existence or validity of any patent rights in connection therewith. The IEEE shall not be responsible for identifying patents for which license may be required by an IEEE standard or for conducting inquiries into the legal validity or scope of those patents that are brought to its attention.

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CONTENTS

IEEE Guide for Electric Power Distribution Reliability Indices

1. Overview

1.1 Scope

This guide identifies distribution reliability indices and factors that affect their calculation. It includes indices, which are useful today, as well as ones that may be useful in the future. The indices are intended to apply to distribution systems, substations, circuits, and defined regions.

1.2 Purpose

The purpose of this guide is twofold. First, it is to present a set of terms and definitions which can be used to foster uniformity in the development of distribution service reliability indices, to identify factors which affect the indices, and to aid in consistent reporting practices among utilities. Secondly, it is to provide guidance for new personnel in the reliability area and to provide tools for internal as well as external comparisons. In the past, other groups have defined reliability indices for transmission, generation, and distribution but some of the definitions already in use are not specific enough to be wholly adopted for distribution. Users of this guide should recognize that not all utilities would have the data available to calculate all the indices.

2. References

The following standards shall be used, when applicable, in preparing manuscripts. When the following standard is superseded by an approved revision, the revision shall apply.

IEEE Std. 859™-1987(R2002), IEEE Standard Terms for Reporting and Analyzing Outage Occurrences and Outage States of Electrical Transmission Facilities.1, 2

IEEE Std 493™-1997(R2002), Recommended Practice for Design of Reliable Industrial and Commercial Power Systems.

1IEEE 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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3. Definitions

Definitions are given here to aid the user in understanding the factors that affect index calculation. Many of these definitions were taken directly from *The Authoritative Dictionary of IEEE Standards Terms,* 7th Edition [B9][3]. If there is a conflict between the definitions in this document and the dictionary, the definitions in this document take precedence. Others are given because they have a new interpretation within this document or have not been previously defined.

3.1 connected load: Connected transformer kVA, peak load, or metered demand (to be clearly specified when reporting) on the circuit or portion of circuit that is interrupted. When reporting, the report should state whether it is based on an annual peak or on a reporting period peak.

3.2 customer: A metered electrical service point for which an active bill account is established at a specific location (e.g., premise).

3.3 customer count: The number of customers either served or interrupted depending on usage.

3.4 distribution system: That portion of an electric system that delivers electric energy from transformation points on the transmission system to the customer.

NOTE—The distribution system is generally considered to be anything from the distribution substation fence to the customer meter. Often the initial overcurrent protection and voltage regulators are within the substation fence and are considered to be part of the distribution system.

3.5 forced outage: The state of a component when it is not available to perform its intended function due to an unplanned event directly associated with that component.

3.6 interrupting device: An interrupting device is a device whose purpose is to interrupt the flow of power, usually in response to a fault. Restoration of service or disconnection of loads can be accomplished by manual, automatic, or motor-operated methods. Examples include transmission circuit breakers, feeder circuit breakers, line reclosers, line fuses, sectionalizers, motor-operated switches or others.

3.7 interruption: The loss of service to one or more customers connected to the distribution portion of the system. It is the result of one or more component outages, depending on system configuration. *See also:* outage.

3 The numbers in brackets correspond to those of the bibliography in Annex D.

3.8 interruption duration: The time period from the initiation of an interruption to a customer until service has been restored to that customer. The process of restoration may require restoring service to small sections of the system (see 5.3.2) until service has been restored to all customers. Each of these individual steps should be tracked collecting the start time, end time and number of customers interrupted for each step.

3.9 interruptions caused by events outside of the distribution system: Outages that occur on generation, transmission, substations, or customer facilities that result in the interruption of service to one or more customers. While generally a small portion of the number of interruption events, these interruptions can affect a large number of customers and last for an exceedingly long duration.

3.10 lockout: Refers to the final operation of a recloser or circuit breaker in an attempt to isolate a persistent fault, or to the state where all automatic reclosing has stopped. The current-carrying contacts of the overcurrent protecting device are locked open under these conditions.

3.11 loss of service: A complete loss of voltage on at least one normally energized conductor to one or more customers. This does not include any of the power quality issues such as: sags, swells, impulses, or harmonics.

3.12 major event: Designates an event that exceeds reasonable design and or operational limits of the electric power system. A Major Event includes at least one Major Event Day (MED).

3.13 major event day: A day in which the daily system SAIDI exceeds a threshold value, T_{MED}. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported. (See 4.5.)

3.14 momentary interruption: A single operation of an interrupting device that results in a voltage zero. For example, two circuit breaker or recloser operations (each operation being an open followed by a close) that momentarily interrupts service to one or more customers is defined as two momentary interruptions.

3.15 momentary interruption event: An interruption of duration limited to the period required to restore service by an interrupting device.

NOTE—Such switching operations must be completed within a specified time of 5 min or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. For example, if a recloser or circuit breaker operates two, three, or four times and then holds (within 5 min of the first operation), those momentary interruptions shall be considered one momentary interruption event.

3.16 outage (electric power systems): The state of a component when it is not available to perform its intended function due to some event directly associated with that component.

NOTES:

(1) An outage may or may not cause an interruption of service to customers, depending on system configuration.

(2) This definition derives from transmission and distribution applications and does not apply to generation outages.

3.17 planned interruption: A loss of electric power that results when a component is deliberately taken out of service at a selected time, usually for the purposes of construction, preventative maintenance, or repair.

NOTES:

(1) This derives from transmission and distribution applications and does not apply to generation interruptions.

(2) The key test to determine if an interruption should be classified as a planned or unplanned interruption is as follows: if it is possible to defer the interruption, the interruption is a planned interruption; otherwise, the interruption is an unplanned interruption.

3.18 planned outage: The state of a component when it is not available to perform its intended function due to a planned event directly associated with that component.

3.19 reporting period: The time period from which interruption data is to be included in reliability index calculations. The beginning and end dates and times should be clearly indicated. All events that begin within the indicated time period should be included. A consistent reporting period should be used when comparing the performance of different distribution systems (typically one calendar year) or when comparing the performance of a single distribution system over an extended period of time. The reporting period is assumed to be one year unless otherwise stated.

3.20 step restoration: A process of restoring interrupted customers downstream from the interrupting device/component in stages over time.

3.21 sustained interruption: Any interruption not classified as a part of a momentary event. That is, any interruption that lasts more than 5 minutes.

3.22 total number of customers served: The average number of customers served during the reporting period. If a different customer total is used, it must be clearly defined within the report.

3.23 unplanned interruption: An interruption caused by an unplanned outage.

4. Reliability indices

4.1 Basic factors
These basic factors specify the data needed to calculate the indices.

i denotes an interruption event

r_i = Restoration Time for each Interruption Event

CI = Customers Interrupted

CMI = Customer Minutes Interrupted

E = Events

T = Total

IM_i = Number of Momentary Interruptions

IM_E = Number of Momentary Interruption Events

N_i = Number of Interrupted Customers for each Sustained Interruption event during theReporting Period

N_{mi} = Number of Interrupted Customers for each Momentary Interruption event during the Reporting Period

N_T = Total Number of Customers Served for the Areas

L_i = Connected kVA Load Interrupted for each Interruption Event

L_T = Total connected kVA Load Served

CN = Total Number of Customers who have Experienced a Sustained Interruption during the Reporting Period

$CNT_{(k>n)}$ = Total Number of Customers who have Experienced more than *n* Sustained Interruptions and Momentary Interruption Events during the Reporting Period.

k = Number of Interruptions Experienced by an Individual Customer in the Reporting Period

T_{MED} = Major event day identification threshold value.

4.2 Sustained interruption indices

4.2.1 System average interruption frequency index (SAIFI)

The system average interruption frequency index indicates how often the average customer experiences a sustained interruption over a predefined period of time. Mathematically, this is given in Equation (1).

$$\mathrm{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}} \qquad (1)$$

To calculate the index, use Equation (2) below.

$$\mathrm{SAIFI} = \frac{\sum N_i}{N_T} = \frac{\mathrm{CI}}{N_T} \qquad (2)$$

4.2.2 System average interruption duration index (SAIDI)

This index indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in customer minutes or customer hours of interruption. Mathematically, this is given in Equation (3).

$$\mathrm{SAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Customers Served}} \qquad (3)$$

To calculate the index, use Equation (4).

$$\mathrm{SAIDI} = \frac{\sum r_i N_i}{N_T} = \frac{\mathrm{CMI}}{N_T} \qquad (4)$$

4.2.3 Customer average interruption duration index (CAIDI)

CAIDI represents the average time required to restore service. Mathematically, this is given in Equation (5).

$$\text{CAIDI} = \frac{\sum \text{Customer Interruption Duration}}{\text{Total Number of Customers Interrupted}} \tag{5}$$

To calculate the index, use Equation 6.

$$\text{CAIDI} = \frac{\sum r_i N_i}{\sum N_i} = \frac{\text{SAIDI}}{\text{SAIFI}} \tag{6}$$

4.2.4 Customer total average interruption duration index (CTAIDI)

This index represents the total average time in the reporting period that customers who actually experienced an interruption were without power. This index is a hybrid of CAIDI and is similarly calculated except that those customers with multiple interruptions are counted only once. Mathematically, this is given in Equation (7).

$$\text{CTAIDI} = \frac{\sum \text{Customer Interruption Duration}}{\text{Total Number of Customers Interrupted}} \tag{7}$$

To calculate the index, use Equation (8).

$$\text{CTAIDI} = \frac{\sum r_i N_i}{\text{CN}} \tag{8}$$

NOTE— In tallying Total Number of Customers Interrupted, each individual customer should only be counted once regardless of number of times interrupted during the reporting period. This applies to 4.2.4 and 4.2.5.

4.2.5 Customer average interruption frequency index (CAIFI)

This index gives the average frequency of sustained interruptions for those customers experiencing sustained interruptions. The customer is counted once regardless of the number of times interrupted for this calculation. Mathematically, this is given in Equation (9).

$$\text{CAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Custers Interrupted}} \tag{9}$$

To calculate the index, use Equation (10)

$$\text{CAIFI} = \frac{\sum N_i}{\text{CN}} \qquad (10)$$

4.2.6 Average service availability index (ASAI)

The average service availability index represents the fraction of time (often in percentage) that a customer has received power during the defined reporting period. Mathematically, this is given in Equation (11).

$$\text{ASAI} = \frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Demands}} \qquad (11)$$

To calculate the index, use Equation (12).

$$\text{ASAI} = \frac{N_T \times (\text{ Number of hours/yr}) - \sum r_i N_i}{N_T \times (\text{ Number of hours/yr})} \qquad (12)$$

NOTE—There are 8760 hours in a non-leap year, 8784 hours in a leap year.

4.2.7 Customers experiencing multiple interruptions (CEMI*n*)

This index indicates the ratio of individual customers experiencing more than n sustained interruptions to the total number of customers served. Mathematically, this is given in Equation (13).

$$\text{CEMI}_n = \frac{\text{Total Number of Customers that experience more than } n \text{ sustained interruptions}}{\text{Total Number of Customers Served}} \qquad (13)$$

To calculate the index, use Equation (14).

$$\text{CEMI}_n = \frac{\text{CN}_{(k>n)}}{N_T} \qquad (14)$$

NOTE—This index is often used in a series of calculations with *n* incremented from a value of one to the highest value
of interest.

4.3 Load based indices

4.3.1 Average system interruption frequency index (ASIFI)

The calculation of this index is based on load rather than customers affected. ASIFI is sometimes used to measure distribution performance in areas that serve relatively few customers having relatively large concentrations of load, predominantly industrial/commercial customers. Theoretically, in a system with homogeneous load distribution, ASIFI would be the same as SAIFI. Mathematically, this is given in Equation (15).

$$\text{ASIFI} = \frac{\sum \text{Total Connected kVA of Load Interrupted}}{\text{Total Connected kVA Served}} \qquad (15)$$

To calculate the index, use Equation (16).

$$\text{ASIFI} = \frac{\sum L_i}{L_T} \qquad (16)$$

4.3.2 Average system interruption duration index (ASIDI)

The calculation of this index is based on load rather than customers affected. Its use, limitations, and philosophy are stated in the ASIFI definition in 4.3.1. Mathematically, this is given in Equation (17).

$$\text{ASIDI} = \frac{\sum \text{Connected kVA Duration of Load Interrupted}}{\text{Total Connected kVA Served}} \qquad (17)$$

To calculate the index, use Equation (18).

$$\text{ASIDI} = \frac{\sum r_i L_i}{L_T} \qquad (18)$$

4.4 Other indices (momentary)

4.4.1 Momentary average interruption frequency index (MAIFI)

This index indicates the average frequency of momentary interruptions. Mathematically, this is given in Equation (19).

$$\text{MAIFI} = \frac{\sum \text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}} \qquad (19)$$

To calculate the index, use Equation (20).

$$\text{MAIFI} = \frac{\sum \text{IM}_i \, \text{N}_{mi}}{N_T} \qquad (20)$$

4.4.2 Momentary average interruption event frequency index (MAIFI*E*)
This index indicates the average frequency of momentary interruption events. This index does not include the events immediately preceding a lockout. Mathematically, this is given in Equation (21).

$$\mathrm{MAIFI}_E = \frac{\sum \text{Total Number of Customer Momentary Interruption Events}}{\text{Total Number of Customers Served}} \qquad (21)$$

To calculate the index, use Equation (22).

$$\mathrm{MAIFI}_E = \frac{\sum \mathrm{IM}_E N_{mi}}{N_T} \qquad (22)$$

4.4.3 Customers experiencing multiple sustained interruption and momentary interruption events (CEMSMI*n*)
This index is the ratio of individual customers experiencing more than n of both sustained interruptions and momentary interruption events to the total customers served. Its purpose is to help identify customer issues that cannot be observed by using averages. Mathematically, this is given in Equation (23).

$$\mathrm{CEMSMI}_n = \frac{\text{Total Number of Customers Experiencing More Than } n \text{ Interruptions}}{\text{Total Number of Customers Served}} \qquad (23)$$

To calculate the index, use Equation (24).

$$\mathrm{CEMSMI}_n = \frac{\mathrm{CNT}_{(k>n)}}{N_T} \qquad (24)$$

4.5 Major event day classification
The following process ("Beta Method") is used to identify MEDs. Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events. This approach supersedes previous major event definitions (see Annex A for sample definitions). For more technical detail on derivation of the methodology refer to Annex B.

A major event day is a day in which the daily system SAIDI exceeds a threshold value, T*MED*. The SAIDI index is used as the basis of this definition since it leads to consistent results regardless of utility size and because SAIDI is a good indicator of operational and design stress. Even though SAIDI is used to determine the major event days, all indices should be calculated based on removal of the identified days.

In calculating daily system SAIDI, any interruption that spans multiple days is accrued to the day on which the interruption begins.

The major event day identification threshold value, T_{MED}, is calculated at the end of each reporting period (typically one year) for use during the next reporting period as follows:

a) Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.

b) Only those days that have a SAIDI/Day value will be used to calculate the T_{MED} (do not include days that did not have any interruptions).

c) Take the natural logarithm (ln) of each daily SAIDI value in the data set.

d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.

e) Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.

f) Compute the major event day threshold, T_{MED}, using equation (25).

$$T_{MED} = e^{(\alpha + 2.5\ \beta)} \qquad (25)$$

g) Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a major event day.

Activities that occur on days classified as major event days should be separately analyzed and reported.

4.5.1 An example of using the major event day definition

An example of using the major event day definition to identify major events and subsequently calculate adjusted indices that reflect normal operating performance is shown in this subclause. This subclause illustrates the calculation of the daily SAIDI, calculation of the major event day threshold T_{MED}, identification of major event days, and calculation of adjusted indices. Table 1 gives selected data for all outages occurring on a certain day for a utility that serves 2,000 customers.

Table 1—Outage data for 1994

Date	Time	Duration (min)	Number of Customers	Interruption Type
3/18	18:34:30	20.0	200	Sustained
3/18	18:38:30	1.0	400	Momentary
3/18	18:42:00	513.5	700	Sustained
NOTE— Although the third interruption was not restored until the following day, its total duration counts in the day that the interruption began. Note also that SAIDI considers only sustained interruptions. Then for 3/18/1994, daily SAIDI (assuming a 2000 customer utility) is given in Equation (26).				

$$SAIDI = \frac{(20 \times 200) + (513 \times 700)}{2000} = 181.73 \text{ min} \tag{26}$$

One month of historical daily SAIDI data is used in the following example to calculate the Major Event Day threshold T_{MED}. Five years of historical data is preferable for this method, but printing that many values in this standard is impractical, so only one month is used to illustrate the concept. The example data is shown in Table 2.

Table 2—One month of daily SAIDI and ln (SAIDI/day) data

Date	SAIDI/day (min)	ln (SAIDI/day)	Date	SAIDI/day (min)	ln (SAIDI/day)
12/1/93	26.974	3.295	12/17/93	0.329	–1.112
12/2/93	0.956	–0.046	12/18/93	0	this day is not included in the calculations since no customers were interrupted.
12/3/93	0.131	–2.033	12/19/93	0.281	–1.268
12/4/93	1.292	0.256	12/20/93	1.810	0.593
12/5/93	4.250	1.447	12/21/93	0.250	–1.388
12/6/93	0.119	–2.127	12/22/93	0.021	–3.876
12/7/93	0.130	–2.042	12/23/93	1.233	0.209
12/8/93	12.883	2.556	12/24/93	0.996	–0.004
12/9/93	0.226	–1.487	12/25/93	0.162	–1.818
12/10/93	13.864	2.629	12/26/93	0.288	–1.244
12/11/93	0.015	–4.232	12/27/93	0.535	–0.626
12/12/93	1.788	0.581	12/28/93	0.291	–1.234
12/13/93	0.410	–0.891	12/29/93	0.600	–0.511
12/14/93	0.007	–4.967	12/30/93	1.750	0.560
12/15/93	1.124	0.117	12/31/93	3.622	1.287
12/16/93	1.951	0.668			
NOTE—The SAIDI/day for 12/18 is zero. The natural logarithm of zero is undefined. Therefore, 12/18/93 is note considered during the analysis					

The value of α, the log-average, is the average of the natural logs, and equals –0.555 in this case.

The value of β, the log-standard deviation, is the standard deviation of the natural logs, and equals 1.90 in this example.

The value of $\alpha + 2.5\beta$ is 4.20.

The threshold value T_{MED} is calculated by $e^{(4.20)}$ and equals 66.69 SAIDI per day. This value is used to evaluate the future time period (e.g., the next year).

Table 3 shows example SAIDI/day values for the first month of 1994.

Table 3—Daily SAIDI data, January 1994

Date	SAIDI/Day	Date	SAIDI/Day
1/1/94	0.240	1/17/94	5.700
1/2/94	0.014	1/18/94	0.109
1/3/94	0.075	1/19/94	0.259
1/4/94	2.649	1/20/94	1.142
1/5/94	0.666	1/21/94	0.262
1/6/94	0.189	1/22/94	0.044
1/7/94	0.009	1/23/94	0.243
1/8/94	1.117	1/24/94	5.932
1/9/94	0.111	1/25/94	2.698
1/10/94	8.683	1/26/94	5.894
1/11/94	0.277	1/27/94	0.408
1/12/94	0.057	1/28/94	237.493
1/13/94	0.974	1/29/94	2.730
1/14/94	0.150	1/30/94	8.110
1/15/94	0.633	1/31/94	0.046
1/16/94	0.434		

The SAIDI/day on 1/28/94 (237.49) exceeds the example threshold value (T_{MED} = 66.69), indicating that the distribution system experienced stresses beyond that normally expected on that day. Therefore, 1/28/94 is classified as a major event day. The SAIDI/day for all other days was less than T_{MED}, indicating that normal stresses were experienced on those days.

To complete the example, indices should be calculated for the following two conditions:

a) all events included

b) major event days removed. In most cases, utilities will calculate all of the indices they normally use (e.g., SAIFI, SAIDI and/or CAIDI). For this example, only SAIDI will be shown. 1994 SAIDI for condition one, all events included, is given in Equation (27) below.

$$\text{SAIDI} = \sum \text{Daily SAIDI} = 287.35 \qquad (27)$$

1994 SAIDI for condition two, major event days removed for separate reporting and analysis, is given in equation 28 below.

$$\text{SAIDI} = \sum \text{Daily SAIDI with the MEDS removed} = 49.86 \qquad (28)$$

5. Application of the indices

Most utilities store interruption data in large computer databases. Some databases are better organized than others for querying and analyzing reliability data. The following section will show one sample partial database and the methodology for calculating indices based on the information provided.

5.1 Sample system

Table 4 shows an excerpt from one utility's customer information system (CIS) database for feeder 7075, which serves 2,000 customers with a total load of 4 MW. In this example, Circuit 7075 constitutes the "system" for which the indices are calculated. More typically the "system" combines all circuits together in a region or for a whole company.

Table 4—Outage data for 1994

Date	Time	Time on	Circuit	Event code	Number of customers	Load kVA	Interruption type
3/17	12:12:20	12:20:30	7075	107	200	800	S
4/15	18:23:56	18:24:26	7075	256	400	1600	M
5/5	00:23:10	01:34:29	7075	435	600	1800	S
6/12	23:17:00	23:47:14	7075	567	25	75	S
7/6	09:30:10	09:31:10	7075	678	2000	4000	M
8/20	15:45:39	20:12:50	7075	832	90	500	S
8/31	08:20:00	10:20:00	7075	1003	700	2100	S
9/3	17:10:00	17:20:00	7075	1100	1500	3000	S
10/7	10:15:00	10:55:00	7075	1356	100	200	S
Interruption type: S– Sustained M– Momementary					Total Customers Served = 2,000		

The total number of customers who have experienced a sustained interruption is 3,215. The total number of customers experiencing a momentary interruption is 2, 400.

Table 5—Extracted customers who were interrupted

Name	Circuit Number	Date	Event code	Duration min
Willis, J	7075	3/17/94	107	8.17
Williams, J	7075	4/15/94	256	0.5
Willis, J	7075	4/15/94	256	0.5
Wilson, D	7075	5/5/94	435	71.3
Willis, J	7075	6/12/94	567	30.3
Willis, J	7075	8/20/94	832	267.2
Wilson, D	7075	8/20/94	832	267.2
Yattaw, S	7075	8/20/94	832	267.2
Willis, J	7075	8/31/94	1003	120
Willis, J	7075	9/3/94	1100	10
Willis, J	7075	10/27/94	1356	40

Table 6—Interrupted device operations

Record Number	Device	Date	Time	Number of Operations	Number of Operations to lockout
1	Brk 7075	4/15	18:23:56	2	3
2	Recl 7075	7/6	09:30:10	3	4
3	Brk 7075	8/2	12:29:02	1	3
4	Brk 7075	8/2	12:30:50	2	3
5	Recl 7075	8/2	13:25:40	2	4
6	Recl 7075	8/25	08:00:00	2	4
7	Brk 7075	9/2	04:06:53	2	3
8	Recl 7075	9/5	11:53:22	3	4
9	Brk 7075	9/8	15:25:10	1	3
10	Recl 7075	10/2	17:15:19	1	4
11	Recl 7075	11/12	00:00:05	1	4

From Table 6, it can be seen that there were eight circuit breaker operations that affected 2000 customers. Each of them experienced 8 momentary interruptions. There were twelve recloser operations that caused 750 customers to experience 12 momentary interruptions. Some of the operations occurred during one reclosing sequence. To calculate the number of momentary interruption events, only count the total number of reclosing sequences. In this case there were five circuit breaker events (records 1, 3, 4, 7, and 9) that affected 2000 customers. Each of them experienced 5 momentary interruption events. There were six recloser events (records 2, 5, 6, 8, 10 and 11) that affected 750 customers each of them experienced 6 momentary interruption events.

5.2 Calculation of indices for a system with no major event days

The equations in Clause 4.5 and definitions in Clause 3 should be used to calculate the annual indices (see Equations (29) – (40)). In the example below, the indices are calculated by using the equations in 4.2 and 4.4 using the data in Table 4 and Table 5, assuming there were no major event days in this data set.

$$\text{SAIFI} = \frac{200 + 600 + 25 + 90 + 700 + 1500 + 100}{2000} = 1.61 \tag{29}$$

$$\text{SAIDI} = \frac{(8.17 \times 200) + (71.3 \times 600) + (30.3 \times 25) + (267.2 \times 90) + (120 \times 700) + (10 \times 1500) + (40 \times 100)}{2000} = 86.11 \text{ min} \tag{30}$$

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{86.110}{1.6075} = 53.57 \text{ min} \tag{31}$$

To calculate CTAIDI and CAIFI, the number of customers experiencing a sustained interruption is required. The total number of customers affected (CN) for this example can be no more than 2000. Since only a small portion of the customer information table is shown it is impossible to know CN; however, it is likely that not all of the 2000 customers on this feeder experienced an interruption during the year. 1800 will be arbitrarily assumed for CN (for your calculations actual information should be used) since the interruption on 9/3 shows that at least 1500 customers have been interrupted during the year.

$$\text{CTAIDI} = \frac{(8.17 \times 200) + (71.3 \times 600) + (30.3 \times 25) + (267.2 \times 90) + (120 \times 700) + (10 \times 1500) + (40 \times 100)}{1800} = 95.68 \text{ min} \tag{32}$$

$$\text{CAIFI} = \frac{200 + 600 + 25 + 90 + 700 + 1500 + 100}{1800} = 1.79 \tag{33}$$

$$\text{ASAI} = \frac{8760 \times 2000 - (8.17 \times 200 + 600 \times 71.3 + 30.3 \times 25 + 267.2 \times 90 + 120 \times 700 + 10 \times 700 + 10 \times 1500 + 40 \times 100)/60}{8760 \times 2000} = 0.999836 \tag{34}$$

$$\text{ASIFI} = \frac{800 + 1800 + 75 + 500 + 2100 + 3000 + 200}{4000} = 2.12 \tag{35}$$

$$\text{ASIDI} = \frac{(800 \times 8.17) + (1800 \times 71.3) + (75 \times 30.3) + (500 \times 267.2) + (2100 \times 700) + 3000(6) + 200 \times 40}{4000} = 444.69 \tag{36}$$

CTAIDI, CAIFI, CEMIn, and CEMSMIn require detailed interruption information for each customer. The database should be searched for all customers who have experienced more than n interruptions that last longer than five minutes. Assume n is chosen to be 5. In Table 5, customer Willis, J. experienced seven interruptions in one year and it is plausible that other customers also experienced more than five interruptions, both momentary and sustained.

For this example, assume arbitrary values of 350 for CN($k > n$), and 750 for CNT($k > n$). The number of interrupting device operations is given in Table 6 and is used to calculate MAIFI and MAIFI$_E$. Assume the number of customers downstream of the recloser equals 750. These numbers would be known in a real system.

$$CEMI_5 = \frac{350}{2000} = 0.175 \quad (37)$$

$$MAIFI = \frac{8 \times 2000 + 12 \times 750}{2000} = 12.5 \quad (38)$$

$$MAIFE_E = \frac{5 \times 2000 + 6 \times 750}{2000} = 7.25 \quad (39)$$

$$CEMSMI_5 = \frac{750}{2000} = 0.375 \quad (40)$$

Using the above sample system should help define the methodology and approach to obtaining data from the information systems and using it to calculate the indices.

5.3 Examples

The following subclause illustrates two concepts: momentary interruptions and step restoration through the use of examples.

5.3.1 Momentary interruption example

To better illustrate the concepts of momentary interruptions and sustained interruptions and the associated indices, consider Figure 1 and Equation 41, Equation 42, and Equation 43. Figure 1 illustrates a circuit composed of a circuit breaker (B), a recloser (R), and a sectionalizer (S).

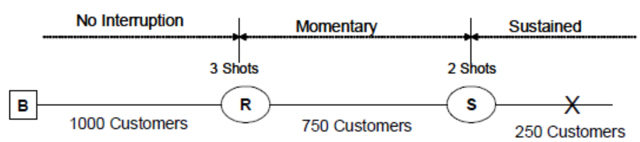


Figure 1—Sample system 2

For this scenario, 750 customers would experience a momentary interruption and 250 customers would experience a sustained interruption. Calculations for SAIFI, MAIFI, and MAIFIE on a feeder basis are shown in Equations 41–43 below. Notice that the numerator of MAIFI is multiplied by 2 because the recloser took two shots, however, MAIFIE is multiplied by 1 because it only counts the fact that a series of momentary events occurred.

$$\mathrm{SAIFI} = \frac{250}{2000} = 0.125 \quad (41)$$

$$\mathrm{MAIFI} = \frac{2 \times 750}{2000} = 0.75 \quad (42)$$

$$\mathrm{MAIFI}_E = \frac{1 \times 750}{2000} = 0.375 \quad (43)$$

5.3.2 Step restoration examples

The following case illustrates the step restoration process. A feeder serving 1000 customers experiences a sustained interruption. Multiple restoration steps are required to restore service to all customers. Table 7 shows the times of each step, a description and associated customers interruptions and minutes they were affected in a time line format.

Table 7—Example 1 for a feeder serving 1000 customers with sustained interruption

Relative Time	Description	Customer Interruptions	Duration (min)	CMI
00:00	1000 customers interrupted.			
00:45	500 customers restored, 500 still out of service.	500	45	22 500
01:00	Additional 300 customers restored, 200 still out of service.	300	60	18 000
01:10	Feeder trips again, 800 previously restored customers are interrupted again. (200 remained out and were not restored at this time.)			
01:30	800 customers restored again.	800	20	16 000
02:00	Final 200 customers restored. Event ends.	200	120	24 000
Totals		1800	N/A	80 500
Example SAIFI = 1800/1000 = 1.8 interruptions Example CAIDI = 80 500/1800 = 44.7 min Example SAIDI = 80 500/1000 = 80.5 min				

Figure 2 illustrates the example described in Table 7. In this example, all of the customers supplied by the circuit were interrupted at the beginning of step 1. Service was restored to a portion of those customers at the end of step 1. Service was restored to another portion of those customers at the end of step 2. Additional customers were interrupted during step 3 (new step 1). Service was restored to additional customers at the end of step 3.

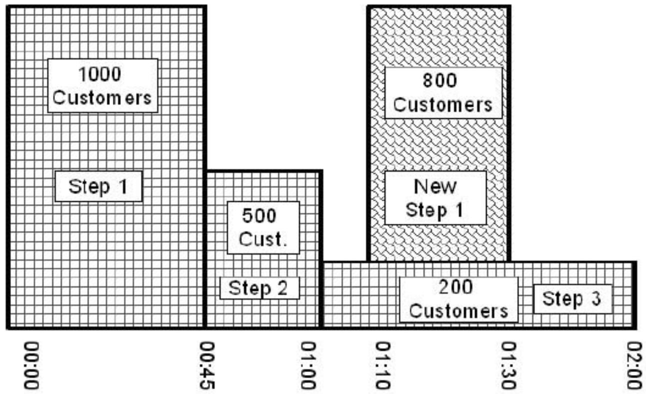


Figure 2—Step restoration time chart

Table 8 shows the information in a format that explains each step and allows the reader to see the calculation steps.

Table 8—Restoration steps for example 1

Steps	Time	Customers Interrupted	CMI
1	00:00–00:45	1000	45 000
2	00:45–01:00	500	7500
3	01:00–02:00	200	12 000
			1
1	01:10–01:30	800	16 000
Total customer for SAIFI count (Only step 1's)		1800	
Total CMI			80 500

6. Information about the factors which affect the calculation of reliability indices

6.1 Rationale behind selecting the indices provided in this guide

One view of distribution system performance can be garnered through the use of reliability indices. To adequately measure performance, both duration and frequency of customer interruptions must be examined at various system levels. The most commonly used indices are SAIFI, SAIDI, CAIDI and ASAI. All of these indices provide information about average system performance. Many utilities also calculate indices on a feeder basis to provide more detailed information for decision making. Averages give general performance trends for the utility; however, using averages will lead to loss of detail that could be critical to decision making. For example, using system averages alone will not provide information about the interruption duration experienced by any specific customer. At the time of this writing, it is difficult for most utilities to provide information on a customer basis. This group envisions that the tracking of specific details surrounding specific interruptions rather than averages will, in the future, be accomplished by improving tracking capabilities. To this end, the working group has included not only the most commonly used indices, but also indices that examine performance at the customer level (e.g., CEMI*n*).

6.2 Factors that cause variation in reported indices

Many factors can cause variation in the indices reported by different utilities. Some examples of differences in the following:

— level of automated data collection
— geography
— system design
— data classification (e.g., are major events in the data set?, planned interruptions?)

To ensure accurate and equitable assessment and comparison of absolute performance and performance trends over time, it is important to classify performance for each day in the data set to be analyzed as either day-to-day or major event day. Not performing this critical step can lead to false decision making because major event day performance often overshadows and disguises daily performance. Interruptions that occur as a result of outages on customer owned facilities or loss of supply from another utility should not be included in the index calculation.

Annex A

(informative)

Survey of reliability index usage

The Working Group on System Design conducted three surveys on distribution reliability index usage. The first one was completed in 1990 and the second was completed in 1995 and the third one was completed in 1997. The purpose of the surveys was to determine index usage and relative index values. In 1990, 100 United States utilities were surveyed, 49 of which responded. In 1995, 209 utilities were surveyed, 64 of which responded. In 1997, 159 utilities were surveyed and 61 responded. Responding utility locations are shown by state in Figure A.1.

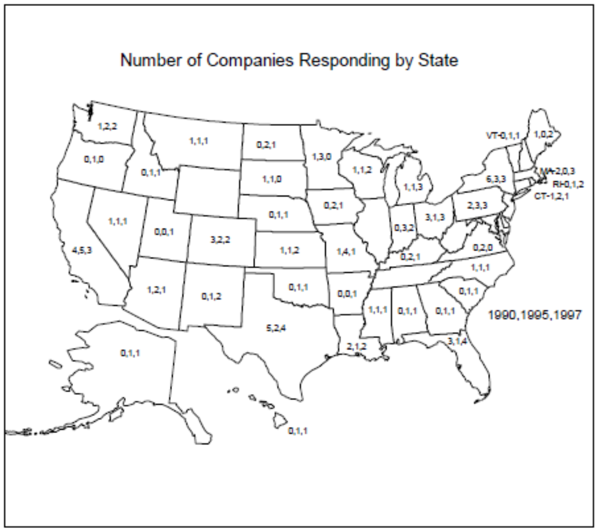


Figure A.1—Location of companies that respond to surveys

Newer surveys are being performed by Edison Electric Institute (EEI). The data provided is not comparable because utilities provided whatever information was easily obtainable. All surveys showed that the most commonly used indices are SAIFI, SAIDI, CAIDI, and ASAI. Figure A.2 shows the percentage of companies using specific indices in 1990. Figure A.3 shows the same information for 1995 and 1997. Figures A.4–A.8 show data on the most commonly used indices given by quartiles where Q1 is the top quartile. The data shown in the Q1 column means that 25% of utilities have an index less than the value shown. For further clarification:

Q1: 25% of utilities have an index less than the value shown
Q2: 50% of utilities have an index less than the value shown (the median value)
Q3: 75% of utilities have an index less the value shown
Q4:100% of utilities have an index less the value shown

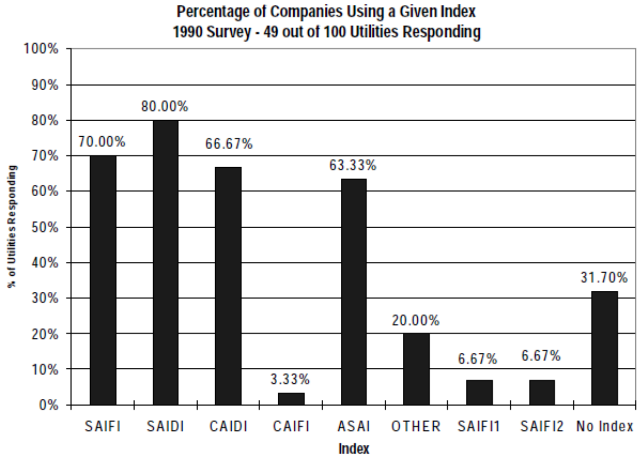


Figure A.2—Percentage of companies using a given index reporting in 1990 (49 out of 100 utilities responding) [B11]

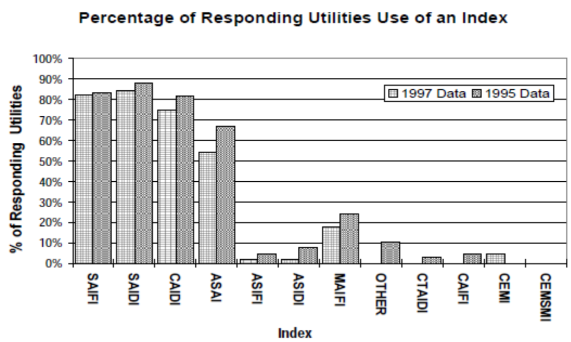


Figure A.3—Percentage of companies using indices reporting in 1995 and 1997 [B1]

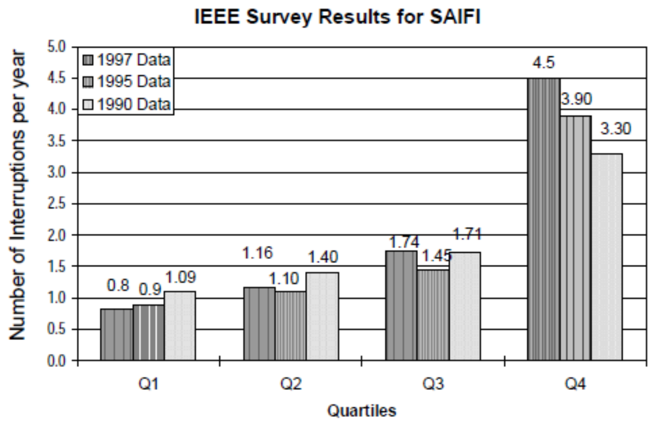


Figure A.4—SAIFI– 1990, 1995 and 1997 survey results [B1] and [B11]

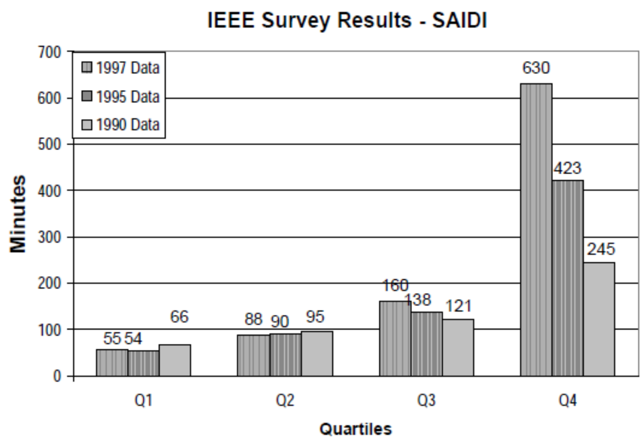


Figure A.5—SAIDI– 1990, 1995, and 1997 survey results [B1] and [B11]

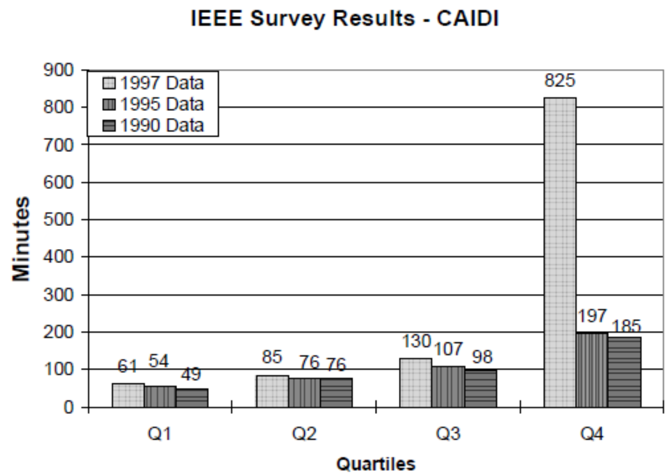


Figure A.6—CAIDI– 1990, 1995, and 1997 survey results

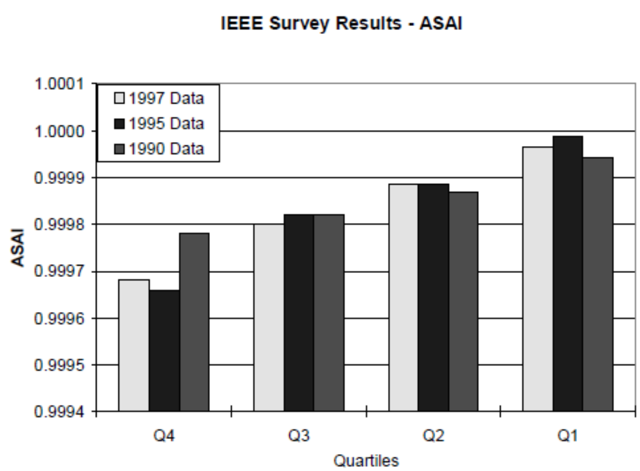


Figure A.7—ASAI– 1990, 1995, and 1997 survey results [B1] and [B11]

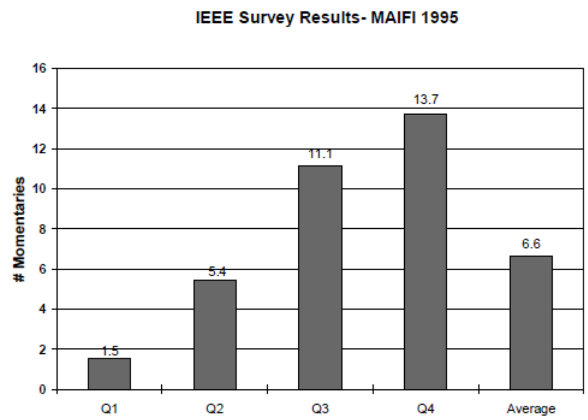


Figure A.8—MAIFIQ– 1995 survey results (1990/7 data not available) [B1]

A.1 Cause codes

In the 1997 survey, cause codes were surveyed. The results are shown below in Figure A.9.

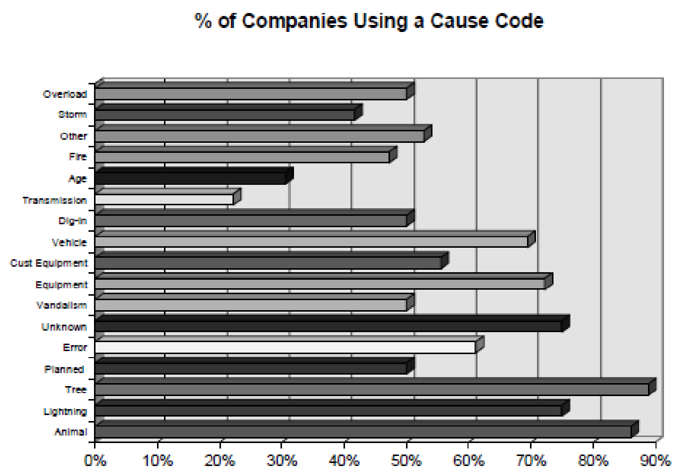


Figure A.9—1997 Cause code usage 1

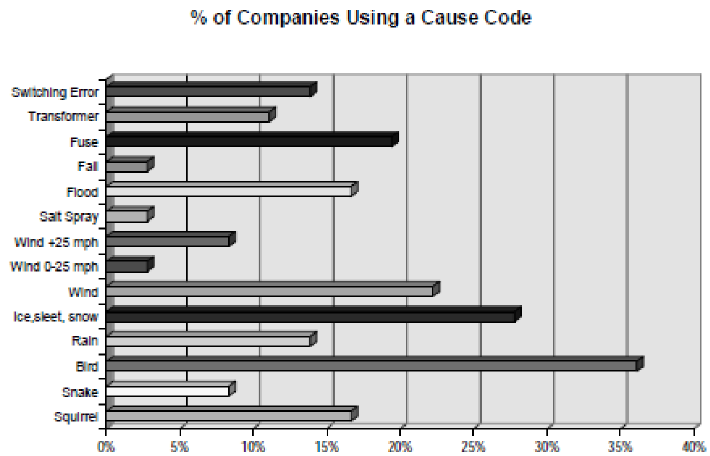


Figure A.10—1997 Cause code usage 2

A.2 Results of question # 7 of the 1999 EEI reliability survey

The following information was provided by the Edison Electric Institute (EEI) based on a survey they performed in 1999. The text is shown exactly as the survey respondents provided the information to EEI.

What definition do you use for major events?

1) Major storm defined as 10% or more of the customer base interrupted in an operating region (based on 8 operating regions) or customers interrupted for 24 hours.

2) Interruptions that result from a catastrophic event that exceeds the design limits of the electric power system, such as an earthquake, tornado, or an extreme storm.

3) A major storm is an event that affects 10% or more of the connected customers with 1% not restored within 24 hours.

4) Ten percent or more of our customers are without power and have been without power for more than 24 hours.
5) The major storm exclusion a criterion is based on a statistical analysis of the last four-year history of reliability data. A cumulative frequency distribution of

the number of locations requiring service restoration work per day is calculated for the four-year period. When the frequency of the restoration work exceeds the 98.5 percentile, by company or region the major storm criterion work be met for the all interruptions for that day.

6) Ten percent of customers in a given region affected by an event plus the last customer out greater than 24 hours. All three of the following must be true:

—widespread damage
—10 000 or 10% of customers served in area affected
—National Weather Service declares severe weather watch or warning for the area

7) Ten percent customer base and 1 customer for 24 hours.

8) More than 15 000 customers out (out of a total customer base of 450 000).

9) As defined by our PUC as named storms, tornados, ice storms, etc.

10) Events where 10% of your customers (meters) have experienced an interruption due to the event.

11) IEEE Std 1366™-1998; Definition 3.12 major event. Company 1 defined as, 10% of the customers within a region without electricity and not restored within a 24 hour period.

12) Ten percent of the entire electric system's customers must experience an interruption in service and one percent of the entire electric system's customers must experience an interruption in service for more than 24 hours.

13) Ten percent of customers out of service and restoration time exceeding 24 hours.

14) Named storms, i.e. hurricane, tropical storms, or tornadoes verified by the National Weather Service. Major forest fires are also included. In addition, Company 2 reporting definition does not include planned interruptions. MAIFI is reported as momentary events.

15) (1) Winds in excess of 90 mph OR (2) 1/2 inch of ice and winds in excess of 40 mph.

NOTE— The major storm outage minutes in 1999 were minimal for Company 3 and did not impact the reliability measures.

16) 0.8 hours x customers served for a month, if the customer hours lost for any one day in that month exceed this value it can be removed from our year-end calculations. Interruptions that result from a catastrophic event that exceeds the design limits of the electric power system, such as an earthquake or an extreme storm. These events shall include situations where there is a loss of power to 10% or more of the customers over a 24-hour period and with all customers not restored within 24 hours.

17) State of Connecticut Department of Public Utility Control – Major Storm Exclusion Definition for 1999 – Any day or 24-hour period, where 31 restoration steps or greater were experienced. For 2000, the UI storm exclusion is based on 35 restoration steps or greater. The change in storm exclusion restoration step threshold, is based on the previous four-year outage history.

18) A period of adverse weather which interrupts 10% or more of the customers served in an operating area, or results in customers being without power for 24 hours or longer.

19) Weather events that cause more than 100 000 customers to be interrupted, with restoration taking at least 24 hours.

20) (1) A Watch or Warning has been issued by the National Weather Service, (2) Extensive mechanical damage has been experienced and (3) More than 6% of the customers served in a region have been affected by outages during a 12-hour period.

21) A major storm is defined as the interruption to 110 000 customers or more which is about 5 percent of our total customers. The 110 000 was arrived at by going out six standard deviations from the mean of all daily cases of trouble.

22) Any outage lasting longer than 48 hours is capped at 48 hours.

23) Any event outage over 10% of the customers in a region AND requiring over 24 hours to restore service to all customers. (PUC definition) Outages occurring during qualifying major storms are not entered into our system, therefore we can only report on 8B, 11B, and 13B below.

24) Determination is subjective, not strictly defined at this time.

25) Tropical storms, hurricanes, tornados, and ice storms.

26) Interruptions that result from a catastrophic event that exceeds the design limits of the electric power system, such as an earthquake or an extreme storm.

These events shall include situations where there is a loss of power to 10% or more customers in a region over a 24-hour period and with all customers not restored within 24 hours.

27) >10% of customers out of service for >24 hours.

28) 15 000 or more customers out of service.

29) Ten percent of customers in an area (region) interrupted.

30) (1) 10% or more of customers interrupted in a operating area. And (2) A storm or other large occurrence where customers experience an interruption for 24 or more hours in an operating area.

31) A storm is determined at regional level when in any consecutive 24 hours the cumulative outages reach 15 AND cumulative customer interruption minutes reach 200 000

32) A major storm is defined as an interruption of electric service resulting from conditions beyond the company's control, which affects at least 10% of the customers in an operating area during the course of an event.

33) Level 3 or above out of 5 according to our emergency plan. About 5 storms per year excluded.

34) Any day during which the number of interruptions are greater than 3 standard deviations above average.

35) CAIDI for the storm period must be 2.5 times normal. Outside crews required to restore damage. Restoration of damage must require 24 hours or more.

36) Named Storms (i.e. hurricane).

37) Extension mechanical damage to the electric system. Outages involving more than 10% of the customers served by district. More than 1% of the customers serviced have not been restored within 24 hours.

38) 15 000 or more customers outages.

39) (1) > 10% of the customers out of service at any one time, reported on a district basis. and (2) Extraordinary storm event such as a tornado, severe winds, etc.

40) A major storm is one which affects 15 000 of our approximately 120 000 customers AND makes an incremental addition of 10 min to company SAIDI.

41) A storm or equipment failure that would cause widespread serious damage throughout the service area in such proportion that available Company 4 forces would be unable to restore service within 48 hours. We designate this as a Level III event – Company 4 has 3 levels of event classifications There were no Level III events in 1999.

42) The major storm exclusion criterion is based on a statistical analysis of the last four-year history of reliability data. A cumulative frequency distribution of the number of locations requiring service restoration work per day is calculated for the four-year period. When the frequency of the restoration work exceeds the 98.5 percentile, by company or region the major storm criterion work be met for the all interruptions for that day.

43) Named storms, tornadoes, ice, events with >10% of customers out.

44) An interruption of electric service resulting from conditions beyond the control of the electric distribution company which affects at least 10% of the customers in an operating area during the course of event for a duration of 5 min each or greater.

45) An interruption of electric service resulting from conditions beyond the control of the electric distribution company which affects at least 10% of the customers in an operating area.

Annex B

(informative)

Major events definition development

B.1 Justification and process for development of the 2.5 beta methodology

The statistical approach to identifying major event days was chosen over the previous definitions (as shown in A.2) because of the difficulties experienced in creating a uniform list of types of major events, and because the measure of impact criterion (i.e., percent of customers affected) required when using event types resulted in non-uniform identification. The new methodology should fairly identify major events for all utilities. Some key issues had to be addressed in order to consider this work successful. They were as follows:

— Definition must be understandable and easy to apply.
— Definition must be specific and calculated using the same process for all utilities.
— Must be fair to all utilities regardless of size, geography, or design.
— Entities that adopt the methodology will calculate indices on a normalized basis for trending and reporting. They will further classify the major event days separately and report on those days through a separate process.

Daily SAIDI values are preferred to daily customer minutes interrupted (CMI) values for major event day identification because the former permits comparison and computation among years with different numbers of customers served. Consider the merger of two utilities with the same reliability and the same number of customers. CMI after the merger would double, with no change in reliability, while SAIDI would stay constant.

Daily SAIDI values are preferred to daily SAIFI values because the former are a better measure of the total cost of reliability events, including utility repair costs and customer losses, than the latter. The total cost of unreliability would be a better measure of the size of a major event, but collection of this data is not practical.

The selected approach for setting the major event day identification threshold, known as the "Two Point Five Beta" method (since it is using the log-normal SAIDI values rather than the raw SAIDI values), is preferred to using fixed multiples of standard deviation (e.g. "Three Sigma") to set the identification threshold because the latter results in non-uniform MED identification among utilities with different sizes and average reliabilities. The b multiplier of 2.5 was chosen because, in theory, it would classify 2.3 days per year as major events. If significantly more days than this are identified, they represent events that have occurred outside the random process that is assumed to control distribution system reliability. The process and the multiplier value were evaluated by a number of utilities with different sized systems from different parts of the United States and found to correlate reasonably well to current major event identification results for those utilities. A number of alternative approaches were considered. None was found to be clearly superior to Two Point Five Beta.

When a major event occurs which lasts through midnight (for example, a six hour hurricane which starts at 9:00 PM), the reliability impact of the event may be split between two days, neither of which would exceed the T_{MED} and therefore be classified as a major event day. This is a known inaccuracy in the method that is accepted in exchange for the simplicity and ease of calculation of the method. The preferred number of years of data (five) used to calculate the major event day identification threshold was set by trading off between the desire to reduce statistical variation in the threshold (for which more data is better) and the desire to see

B.1.1 Remarks

To generate the example data, values of a and b were taken from an actual utility data set, and then daily SAIDI/day values were artificially generated using a log normal distribution with these values of α and β. The daily SAIDI values were then adjusted to illustrate all aspects of the calculation, e.g. a day in Table 2 was assigned a SAIDI value of zero, and a day in Table 3 was assigned a SAIDI value higher than the computed threshold.

This annex provides a technical description and analysis of the 2.5® method of identifying MEDs in distribution reliability data. The 2.5® method is a statistical method based on the theory of probability and statistics. Fundamental concepts such as probability distribution and expected value are highlighted in italics when they are first used, and provided with a short definition. An undergraduate probability and statistics textbook can be consulted for more complete definitions.

B.1.2 Beta (β) method description

A threshold on daily SAIDI is computed once a year (see 4.5). The short version is as follows:

a) Assemble the five most recent years of historical values of SAIDI/day. If less than five years of data is available, use as much as is available.

b) Discard any day in the data set that has a SAIDI/Day of zero.

c) Find the natural logarithm of each value in the data set.

d) Compute the average (α, or Alpha) and standard deviation (β, or Beta) of the natural logarithms computed in step 3.

e) Compute the threshold T_{MED} = exp (Alpha + 2.5 * Beta).

f) Any day in the next year with SAIDI > T_{MED} is a major event day.

B.2 Random nature of distribution reliability

The reliability of electric power distribution systems is a random process, that is, a process that produces random values of a specific random variable. A simple example of a random process is rolling a die. The random variable is the value on the top face of the die after a roll, which can have integer values between 1 and 6.

In electric power distribution system reliability, the random variables are the reliability indices defined in the guide. These are evaluated on a daily or yearly basis, and take on values from zero to infinity.

B.3 Choice of SAIDI to identify major event days

Four commonly used reliability indices are:

— System Average Interruption Duration Index (SAIDI)
— System Average Interruption Frequency Index (SAIFI)
— Customer Average Interruption Duration Index (CAIDI)
— Average Service Availability Index (ASAI)

These indices are actually measures of unreliability, as they increase when reliability becomes worse.

An ideal measure of unreliability would be customer cost of unreliability, the dollar cost of power outages to a utility's customers. This cost is a combination of the initial cost of an outage and accumulated costs during the outage. Unfortunately, the customer cost of unreliability has so far proven impossible to estimate accurately. In contrast, the reliability indices above are routinely and accurately computed from historical reliability data. However, the ability of an index to reflect customer cost of unreliability indicates the best one to use for major event day identification.

Duration-related costs of outages are higher than initial costs, especially for major events, which typically have long duration outages. Thus a duration-related index will be a better indicator of total costs than a frequency-related index like SAIFI or MAIFI. Because CAIDI is a value per customer, it does not reflect the size of outage events. Therefore SAIDI best reflects the customer cost of unreliability, and is the index used to identify major event days. SAIDI in minutes/day is the random variable used for major event day identification.

The use of Customer Minutes Interrupted per day was also considered. Like SAIDI, CMI is a good representation of customer cost of unreliability. In fact, SAIDI is just CMI divided by the number of customers in the utility. The number of customers can vary from year to year, especially in the case of mergers, and multiple years of data are used to find major event days. Use of SAIDI accounts for the variation in customer count, while use of CMI does not. Therefore SAIDI is preferred.

B.4 Probability distribution of distribution system reliability

B.4.1 Probability density functions and probability of exceeding a threshold value

MEDs will be days with larger SAIDI values. This suggests the use of a threshold value for daily SAIDI. The threshold value is called T_{MED}. Days with SAIDI greater than T_{MED} are major event days. As the threshold increases, there will be fewer days with SAIDI values above the threshold. The relationship between the threshold and the number of days with SAIDI above the threshold is given by the probability density function of SAIDI/day.

The probability density function gives the probability that a specific value of a random variable will appear. For example, for a six sided die, the probability that a one will appear in a given roll is 1/6th, and the value of the probability density function of one is 1/6th for this random process.

The probability that a value greater than one will occur is just the sum of the probability densities for all values greater than one. Since each value has a probability density of 1/6th for the example, this sum is just 5/6ths. As the threshold increases, the probability decreases. For example, for a threshold of 4, there are only two values greater than 4, and the probability of rolling one of them is 2/6ths or 1/3rd.

In the die rolling example, the random variable can only have discrete integer values. SAIDI/day is a continuous variable. In this case, the sum is replaced by an integral. The probability p that any given day will have a SAIDI/day value greater than a threshold value T is the integral of the probability density function from the threshold to infinity as shown below in Equation (B.1).

$$p(\text{SAIDI} > T) = \int_T^{\infty} pdf(\text{SAIDI})\, d\text{SAIDI} \qquad \text{(B.1)}$$

Graphically, the probability is the area under the probability density function above the threshold, as shown in Figure B.1.

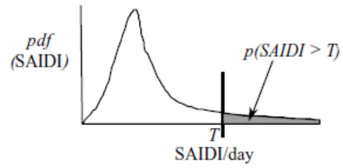


Figure B.1—The area under the probability density function *pdf* (SAIDI) above threshold (T) is the probability *p* that a given day will have a SAIDI value greater than (T)

If any given day has a probability p of being a major event day, then the expected value [see Equation (B.2)] of the number of major event days in a year is the probability times the number of days in a year.

$$E(MED/year) = 365 \cdot p(\text{ SAIDI} > \mathrm{T}_{MED}) \qquad \text{(B.2)}$$

For example, if $p = 0.1$, then the expected number of major event days in a year is 36.5. This does not mean that exactly 36.5 MEDs will occur. The actual number will vary due to the randomness of the process.

Using the die rolling example, the probability of getting a six in any roll is 1/6th. Therefore the expected number of sixes in six rolls is 1. However, if the die is rolled six times, there could be six sixes, or zero sixes, or any number in between. As the number of trials goes up, the number of sixes will approach 1/6th of the number of rolls, but for small numbers of rolls there will be some variation from the expected value.

B.4.2 Gaussian, or normal distribution

The expected number of MEDs per year can be computed for any given threshold if the shape of the probability density function is known. The shape of the probability density function is called the probability distribution. Specific types of shapes have specific names. The most well known is the Gaussian distribution, also called the normal distribution or bell curve, shown in Figure B.2.

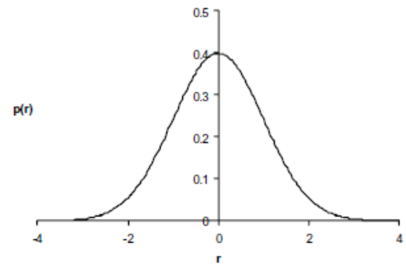


Figure B.2—Gaussian or normal probability distribution

The Gaussian distribution is completely described by its mean, or average value, (μ or Mu) and its standard deviation (σ or Sigma). The average value is at the center of the distribution (at 0 on the *x* axis in Figure B.2) and the standard deviation is a measure of the spread of the distribution.

An important property of the Gaussian distribution is that the probability of exceeding a given threshold is a function of the number of standard deviations the threshold is from the mean. Equation (B.3) provides mathematical terms.

$$T_{MED} = \mu + n\sigma \qquad \text{(B.3)}$$

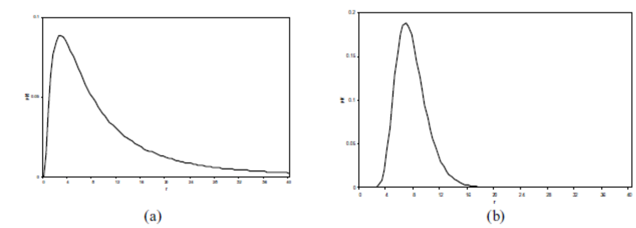
If the threshold is *n* standard deviations greater than the mean, and the probability of exceeding the threshold, $p(\text{SAIDI} > T_{MED})$, is a function only of *n*, and not of the mean and standard deviation. Values for this function are found in tables in the backs of probability textbooks and in, for example, standard spreadsheet functions. Table B.1 gives the probability of exceeding the threshold for different number of standard deviations *k*.

B.4.3 Three sigma

The term “Three Sigma” is often used loosely to designate a rare event. It comes from the Gaussian probability distribution. As Table B.1 shows, the probability of exceeding a threshold that is three standard deviations more than the mean is 0.00135, or one and a half tenths of a percent. If daily SAIDI had a Gaussian probability distribution, it would be relatively easy to agree on a Three Sigma definition for the major event day threshold, T_{MED}. Unfortunately, SAIDI does NOT have a Gaussian distribution. It has a log-normal distribution.

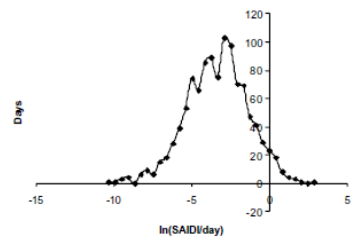
B.5 Log-normal distribution

The random variable in the Gaussian distribution has a range from –∞ to ∞. In real life, many quantities, including distribution reliability, can only be zero or positive. This causes the probability distribution to skew, bunching up near the zero axis and having a long tail to the right. The degree of skewness depends on the ratio of mean to standard deviation. When the standard deviation is small compared to the mean, the log normal distribution looks like the Gaussian distribution, as shown in Figure B.3(b). When it is large compared to the mean, it does not, as shown in Figure B.3(a). Daily reliability data usually has standard deviation values far larger than the mean.



(a) Less than standard deviation.
(b) Greater than standard deviation.

Figure B.3—Log-normal distributions



This indicates three years of daily SAIDI data from anonymous Utility 2 supplied by the Distribution System Design Working Group. The logs of the data are normally distributed, so the daily data is log-normally distributed.

Figure B.4—Histogram of the natural logs

A consequence of the log-normality of daily reliability data is that the three sigma conditions no longer hold. In particular, the probability of exceeding a given threshold is no longer independent of the values of the average and standard deviation of the distribution. This means that using a method such as Three Sigma would result in different numbers of MEDs for utilities with different average values of reliability, or with different standard deviation values. This seems inequitable.

Fortunately, the logarithms of log-normal data have a Gaussian distribution. If the average of the logarithms of the data is called α, or Alpha, and the standard deviation of the logarithms of the data is called ß, or Beta, then α and ß are the mean and standard deviation of a Gaussian distribution and a threshold on the log of the data can be set which is independent of the values of 〈 and ß. Equations (B.4) and (B.5) show these concepts mathematically.

$$\ln(T_{MED}) = \alpha + k\beta \qquad \text{(B.4)}$$

and

$$T_{MED} = \exp(\alpha + k\beta) \qquad \text{(B.5)}$$

The probability of exceeding T_{MED} is a function of *k*, just as in the Gaussian example. Table B.2 gives these probabilities as well as the expected number of Major Event Days (MEDs) for various values of *k*.

B.5.1 Why 2.5?

Given an allowed number of MEDs per year, a value for *k* is easily computed. However, there is no analytical method of choosing an allowed number of MEDs/year. The chosen value of *k* = 2.5 is based on consensus reached among Distribution Design Working Group members on the appropriate number of days that should be classified as Major Event Days. As Table B.2 shows, the expected number of days for *k* = 2.5 is 2.3 MEDs/year. In practice, the experience of the committee members, representing a wide range of distribution utilities, was that more than 2.3 days were usually classified as MEDs, but that the days that were classified as MEDS were generally those that would have been chosen on qualitative grounds. The performance of different values of k were examined, and consensus was reached on *k* = 2.5.

B.6 Fairness of the 2.5ß method

It is likely that reliability data from different utilities will be compared by utility management, public utilities commissions and other interested parties. A fair MED classification method would classify, on average, the same number of MEDs per year for different utilities.

The two basic ways that utilities can differ in reliability terms are in the mean and standard deviation of their reliability data. Differences in means are attributable to differences in the environment between utilities, and to differences in operating and maintenance practices. Differences in standard deviation are mostly attributable to size. Larger utilities have inherently smaller standard deviations. As discussed above, using the mean and standard deviation of the logs of the data (α and β) to set the threshold makes the expected number of MEDs depend only on the multiplier, and thus should classify the same number of MEDs for large and small utilities, and for utilities with low and high average reliability.

This is not the case for using the mean and standard deviation of the data without taking logarithms first. The expected number of MEDs varies the average and standard deviation. This variation occurs because of the log-normal nature of the reliability probability distribution.

B.7 Five years of data

From a statistical point of view, the more data used to calculate a threshold, the better. However, the random process producing the data changes over time as the distribution system is expanded and operating procedures are varied. Using too much historical data would suppress the effects of these changes.

The addition of another year of data should have a low probability of changing the MED classification of previous years. A result from order statistics gives the probability that the *k*th largest value in m samples will be exceeded f times in n future samples [B10]. It is given in Equation (B.5).

$$p_{f \backslash m,k,n} = \frac{k}{n+k-f} \frac{\binom{m}{k}\binom{n}{f}}{\binom{n+m}{n+k-f}} \qquad \text{(B.5)}$$

For example, if $M = 3$ years of data then $m = 1095$ samples. If $f = 3$ MEDs/year then the largest non-MED is the k = 1095 –9 = 1086th ordered sample. The probability of $f = 3$ days in the next year of $n = 365$ samples exceeding the size of the largest non-MED is found from the equation to be 0.194 (19.4%). In Figure B.5 *p* is plotted against M for several values of *f*.

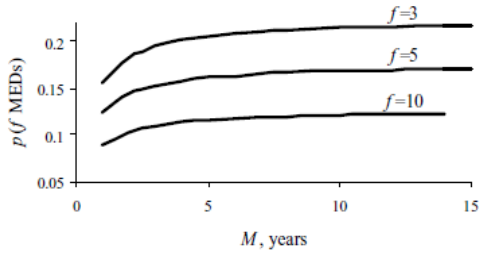


Figure B.5—Probability of exactly new MEDs in the next year of data, using *M* years of historical data

The consensus of the Design Working Group members was that 5 years was the appropriate amount of data to collect. They felt that the distribution system would change enough to invalidate any extra accuracy from more than 5 years of data.

Annex C

(informative)

Internal data subset

C.1 Calculation of reliability indices for subsets of data for internal company use

Reliability performance can be assessed for different purposes. It may be advantageous to calculate reliability indices without planned interruptions in order to review performance during unplanned events. In another case, it may be advantageous to review only sustained interruptions. Assessment of performance trends and goal setting should be based on normal event days (neglecting the impact of MEDs). Utilities and regulators determine the most appropriate data to use for reliability performance monitoring. When indices are calculated using partial data sets, the basis should be clearly defined for the users of the indices. At a minimum, reliability indices based on all collected data for a reporting period and analyzed as to normal versus major event day classifications should be provided. Indices based on subsets of collected data may be provided as specific needs dictate.

Annex D

(informative)

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Made by the Authority, after consultation with the Governor and the licensee, the 8th day of March, 2012.

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