A Touchstone Energy® Cooperative

April 4, 2008

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Mr. Jim Welch
Director of Engineering
Public Service Commission
P. 0. Box 615
Frankfort, KY 40602-0615

RE: Administrative Case No. 2006-0494

Dear Mr. Welch:

Enclosed are an original and five (5) copies of the 2007 Distribution Reliability Report for Nolin Rural Electric Cooperative Corporation as requested in the above order dated October 26, 2007.

If you have any questions on the content of the responses please contact Vince Heuser, Vice President of System Operations at the Nolin Rural Electric Cooperative Corporation office in Elizabethtown, KY [270-765-6153].

Sincerely,

Roger Dean Wilson
Wilson Consulting INC

Enclosure

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A Touchstone Energy Cooperative

2007 PSC Distribution Reliability Report

In regards to Administrative Case NO. 2006-00494

Prepared by

NOLIN RURAL ELECTRIC COOPERATIVE CORPORATION

&

ENVISION ENERGY SERVICES

Roger Wilson, PE

April 4, 2008

Table of Contents

1. Purpose of Report

This report is pursuant to the Public Service Commission's request for all electric distribution utilities to provide annual reports of reliability information as outlined in the findings from administrative case no. 2006-00494. This report documents the reliability performance of **Nolin Rural Electric Cooperative Corporation** in Elizabethtown, Kentucky for 2003-2007calendar year.

Results in this report will be based on indices defined in IEEE Standard 1366-2003, and will be reported on both system wide level; as well as on the circuit level for the purpose of determining the ten worst performing circuits in Nolin's system. In this analysis major event days will not be included. (Major Event Days are as described in the IEEE 1366-2003 Standard.)

2. Historical Data

Table 2.1 shows the reliability indices for the Nolin system for the past eight years. The averages shown in the last line are for the last five years. These indices reflect all outages including outages caused by major storms for reference. (IEEE 1366 for identifying Major Event Days)

Table 2.1 Historical Indices
For
- SAIDI – CAIDI – SAIFI -

SAIDI						CAIDI	SAIFI
In minutes						**In minutes**	
	All	**MED**	**PS**	**Sched**	**Other**	**All**	
2000	56.9	7.4	0.0	2.7	46.8	390.7	0.15
2001	51.1	0.0	0.0	0.2	50.9	74.0	0.69
2002	123.9	80.7	0.0	0.6	42.6	89.0	1.39
2003	93.2	37.3	0.0	1.2	54.7	100.5	0.93
2004	736.8	669.4	4.2	1.6	61.5	308.8	2.39
2005	93.3	40.5	0.4	0.2	52.2	104.1	0.90
2006	104.8	60.7	0.0	0.0	44.0	159.6	0.66
2007	20.4	0.0	0.0	0.2	20.2	64.4	0.32
2003-2007 Avg.	**209.7**	**161.6**	**0.9**	**0.7**	**46.5**	**147.5**	**1.0**

3. Outage Causes By Coding

Nolin tracks the causes of outages through phone calls by consumers to the 24 hour dispatch department, monitored Turtle AMR and SCADA. All outages are recorded and kept as a permanent file after service has been restored. The cause categories, number of events, consumers interrupted, consumer minutes, and SAIDI calculation are all shown in Table 3. 1. This table gives an intensity of reliability indices for each cause category group.

Table 3.l Outages by Cause Codes

Cause	# events	CI	CMI	SAIDI
LIGHTNING	192	2628	17194	0.5331
EQUIPMENT / MATERIAL FAILURE	84	1954	9622	0.2983
TREES	63	500	9286	0.2879
UNKNOWN CAUSE	51	2481	3259	0.1010
MAINTENANCE	30	45	2577	0.0799
DAMAGED MATERIAL OR EQUIP	17	22	1716	0.0532
SMALL ANIMALS OR BIRDS	29	1656	1711	0.0531
PUBLIC ACCIDENTS, OTHER	14	104	1348	0.0418
WIND, HIGH WIND	10	92	1169	0.0362
OTHER WEATHER	6	129	1009	0.0313
MEMBER CAUSED	7	8	691	0.0214
NO CAUSE CODE	12	704	579	0.0180
ELECTRICAL OVERLOAD	7	7	554	0.0172
OTHER, FAULTY EQUIPMENT	4	4	427	0.0132
DECAY OR CORROSION	3	5	316	0.0098
DECAY OR CORROSION	3	5	316	0.0098
PUBLIC ACTIVITIES, OTHER	2	2	269	0.0083
CONTRACTOR	3	43	221	0.0069
HOUSE MOVER	1	1	217	0.0067
CONSTRUCTION	4	29	213	0.0066
TREES AND ICE	2	2	209	0.0065
FIRE	5	5	196	0.0061
CONDUCTOR SAG	1	1	108	0.0033
CONTAMINATION OR LEAKAGE	1	1	83	0.0026
LARGE ANIMALS	1	1	68	0.0021
FARM EQUIP.	1	1	55	0.0017

4. Ten Worst Circuits By SAIDI And SAIFI

Table 3.1 Outages by circuit

Ten worst circuits based on SAIDI

Sub	Ckt	Sub & ckt	SAIDI	Major cause based on CMI
Upton	1	7 (1)	6.199	Lightning
Tunnel Hill 2	3	19 (3)	1.870	Lightning
Magnolia	1	5 (1)	1.632	Power supply
Tunnel Hill 2	4	19 (4)	1.577	Equipment failure
Smithersville 2	3	17 (3)	1.278	Lightning
Vine Grove	3	9 (3)	0.882	Unknown cause
Logsdon	3	18 (3)	0.794	Trees
Stephenburg	3	6 (3)	0.772	Lightning
Williams	3	16 (3)	0.676	Other weather
Rineyville	4	21 (4)	0.649	Lightning

Table 3.2 Outages by circuit

Ten worst circuits based on SAIFI

Sub	Ckt	Sub & ckt	SAIFI	Major cause based on CMI
Upton	1	7 (1)	3.7787	Lightning
Tunnel Hill 2	4	19 (4)	2.0092	Equipment failure
Smithersville 2	3	17 (3)	1.2935	Lightning
Upton	5	7 (5)	1.2015	Unknown
Logsdon	3	18 (3)	1.1463	Trees
Rineyville	4	21 (4)	0.9968	Lightning
Tunnel Hill 2	3	19 (3)	0.9584	Lightning
Magnolia	1	5 (1)	0.8945	Power supply
Vine Grove	3	9 (3)	0.4566	Lightning
Glendale	5	3 (5)	0.3084	Lightning

The reliability indices were calculated for each feeder, and the ten worst performing feeders for each index were identified. Each feeder was analyzed as its own "system" in that only the consumers served on a given feeder were used in the calculation of the index for that feeder. Tables 3.1 and 3.2 on the following pages show the results of the feeder analysis for each index listed from highest to lowest in reliability. Further analysis of the "ten worst performing feeders" reveals the major percentage of the consumer hours by frequency (SAIFI) can be attributed to weather events. Nearly every one of these events can be attributed to lightning and ultimately to a failure of the arrester itself. Nolin has diligently deployed lightning arrester protection across its entire distribution system as recommended by the Rural Utilities Services guide of four (4) arresters per mile. Additionally, lightning arresters are installed at all line equipment locations and critical junction points. This approach clearly offers a high degree of system protection from lightning and as a result, a higher degree of overall reliability. The "down-side" to this is when an arrester failure occurs it is usually catastrophic in nature, resulting in the sectionalizing of the affected circuit. Repair and service restoration efforts are generally prolonged because they are performed typically under adverse conditions.

The equipment failures and unknown cause can, in many cases, be associated to lightning. The weakened device from a lightning stroke may prematurely fail with a normal operation. The events that take place shortly after an electrical storm can be a strong example of this fact.

It should also be noted that only two circuits show up as 'top ten' circuits as Tree Causes. This is a case in point of the Nolin's present vegetation management program.

IEEE Standard 1366-2003

Guide for Electric Power Distribution Reliability Indices

[Following]

IEEE Standards

IEEE Std 1366™-2003
(Revision of IEEE Std 1366-1998)

1366™

IEEE Guide for Electric Power Distribution Reliability Indices

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of the
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Approved 10 December 2003

IEEE-SA Standards Board

Grateful acknowledgment is made to the Edison Electric Institute for the permission to use the following source material:

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

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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.

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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.

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

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

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.

NOTE—

(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.

NOTE—

(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 the Reporting 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).

$$\text{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}} \tag{1}$$

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

$$\text{SAIFI} = \frac{\Sigma N_i}{N_T} = \frac{\text{CI}}{N_T} \tag{2}$$

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).

$$\text{SAIDI} = \frac{\sum \text{Customer Interruption Durations}}{\text{Total Number of Customers Served}} \tag{3}$$

To calculate the index, use Equation (4).

$$\text{SAIDI} = \frac{\Sigma r_i N_i}{N_T} = \frac{\text{CMI}}{N_T} \tag{4}$$

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.

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

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)

$$\text{CAIFI} = \frac{\sum N_i}{\text{CN}} \tag{10}$$

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).

$$\text{ASAI} = \frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Demands}} \tag{11}$$

To calculate the index, use Equation (12).

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

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).

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

To calculate the index, use Equation (14).

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

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).

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

To calculate the index, use Equation (16).

$$\text{ASIFI} = \frac{\sum L_i}{L_T} \tag{16}$$

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).

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

To calculate the index, use Equation (18).

$$\text{ASIDI} = \frac{\sum r_i L_i}{L_T} \tag{18}$$

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).

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

To calculate the index, use Equation (20).

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

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).

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

To calculate the index, use Equation (22).

$$\mathrm{MAIFI}_E = \frac{\sum \mathrm{IM}_E N_{mi}}{N_T} \tag{22}$$

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).

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

To calculate the index, use Equation (24).

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

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).

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

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).				

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

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.

$$\text{SAIDI} = \sum \text{Daily SAIDI} = 287.35 \tag{27}$$

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

$$\text{SAIDI} = \sum \text{Daily SAIDI with the MEDS removed} = 49.86 \tag{28}$$

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.

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

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

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

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.

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

$$\mathrm{CAIFI} = \frac{200 + 600 + 25 + 90 + 700 + 1500 + 100}{1800} = 1.79 \quad (33)$$

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

$$\mathrm{ASIFI} = \frac{800 + 1800 + 75 + 500 + 2100 + 3000 + 200}{4000} = 2.12 \quad (35)$$

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

CTAIDI, CAIFI, CEMI_n, and CEMSMI_n 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 $\mathrm{CN}(k > n)$, and 750 for $\mathrm{CNT}(k > n)$. 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.

$$\mathrm{CEMI}_5 = \frac{350}{2000} = 0.175 \quad (37)$$

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

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

$$\mathrm{CEMSMI}_5 = \frac{750}{2000} = 0.375 \quad (40)$$

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).

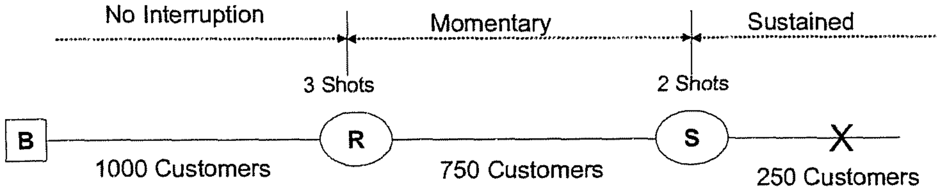


Figure 1—Sample system 2

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.

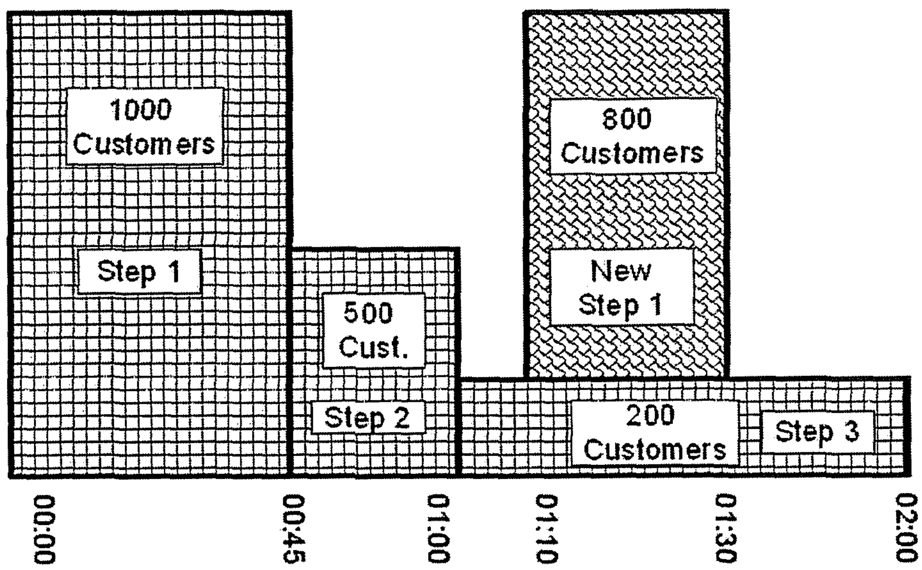


Figure 2—Step restoration time chart

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. Newer surveys are being performed by Edison Electric Institute (EEI). The data provided is not comparable because utilities provided whatever information was easily obtainable.

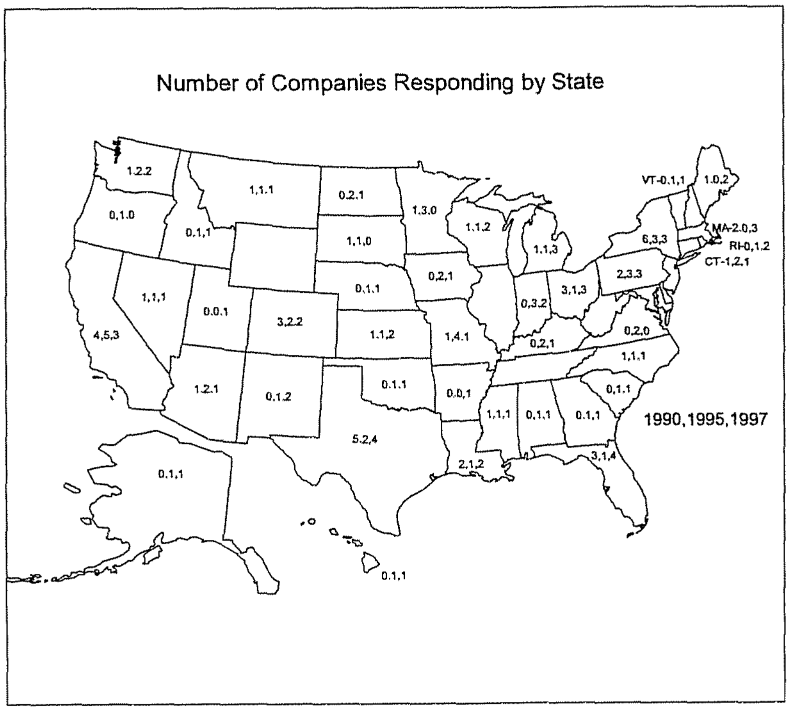


Figure A.1—Location of companies that respond to surveys

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

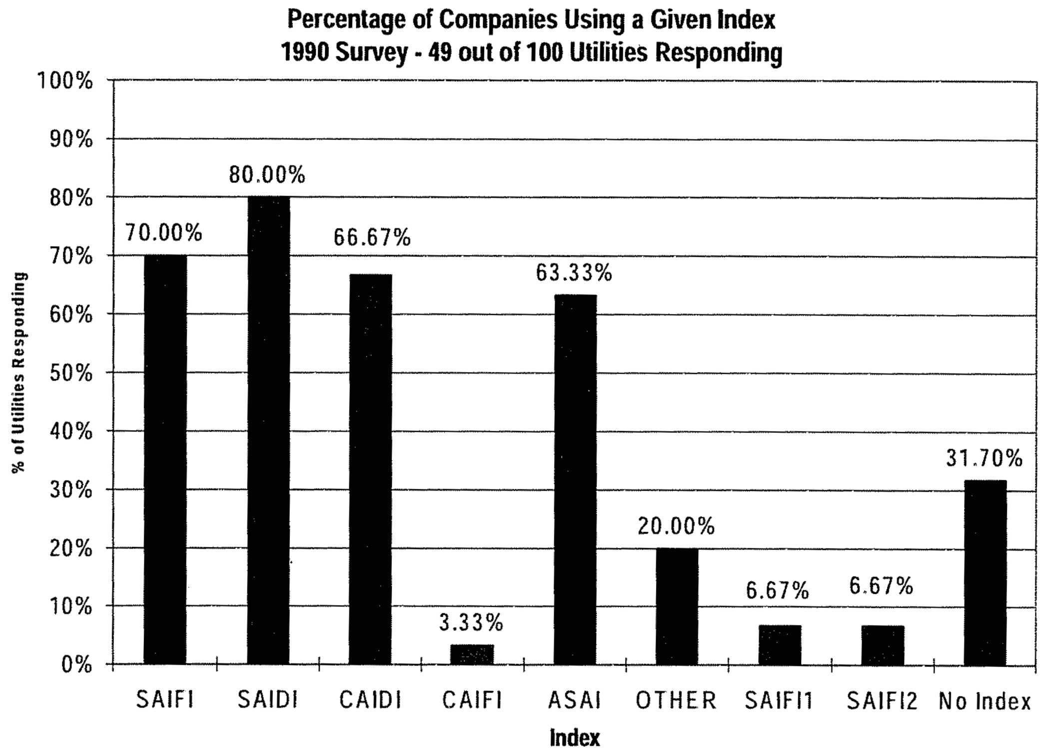


Figure A.2—Percentage of companies using a given index reporting in 1990 (49 out of 100 utilities responding) [B11]

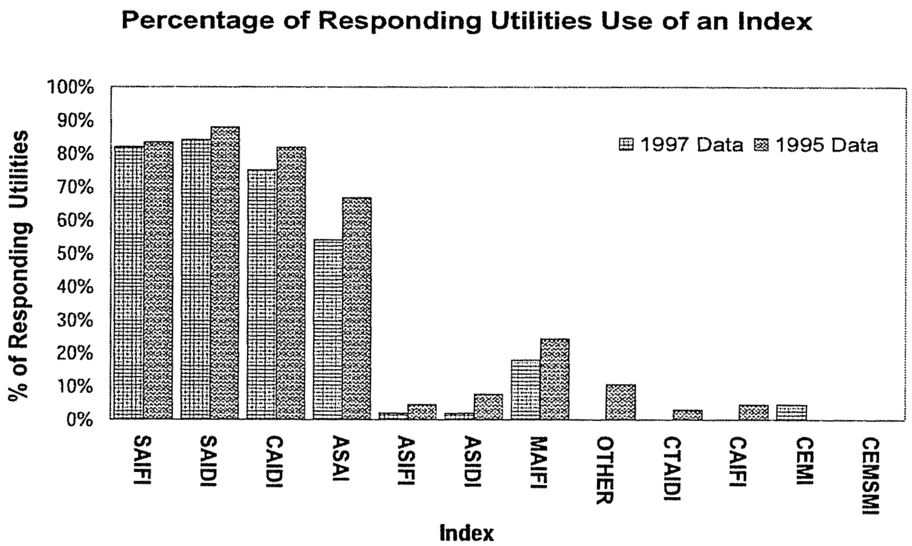


Figure A.3—Percentage of companies using indices reporting in 1995 and 1997 [B1]

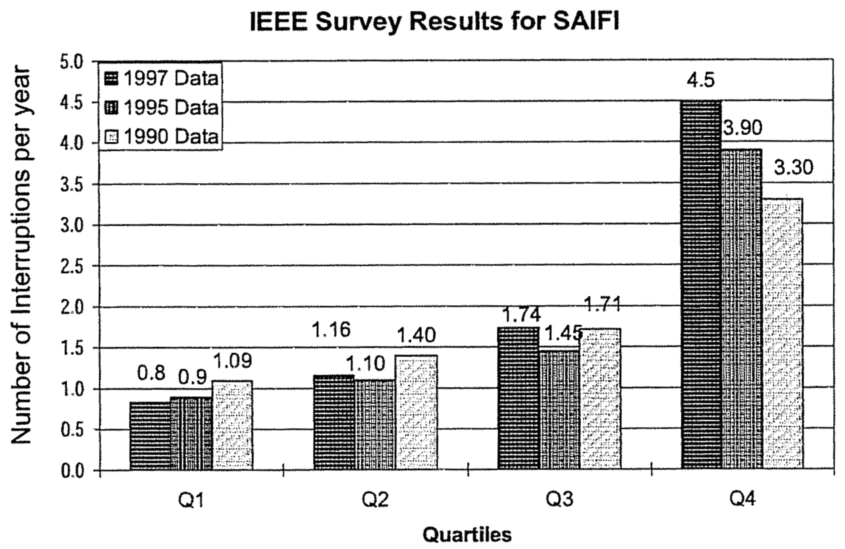


Figure A.4—SAIFI– 1990, 1995 and 1997 survey results [B1] and [B11]

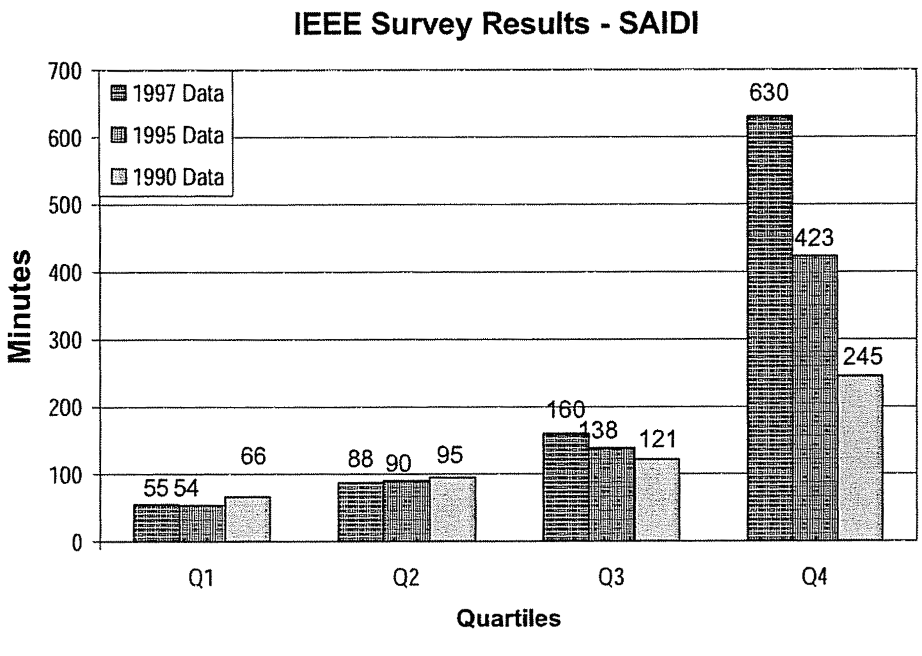


Figure A.5—SAIDI– 1990, 1995, and 1997 survey results [B1] and [B11]

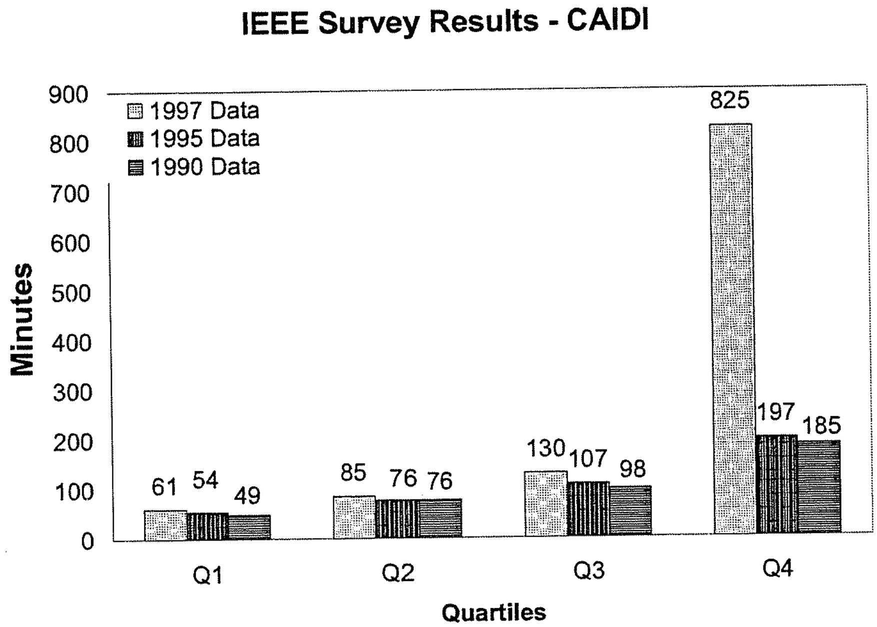


Figure A.6—CAIDI– 1990, 1995, and 1997 survey results

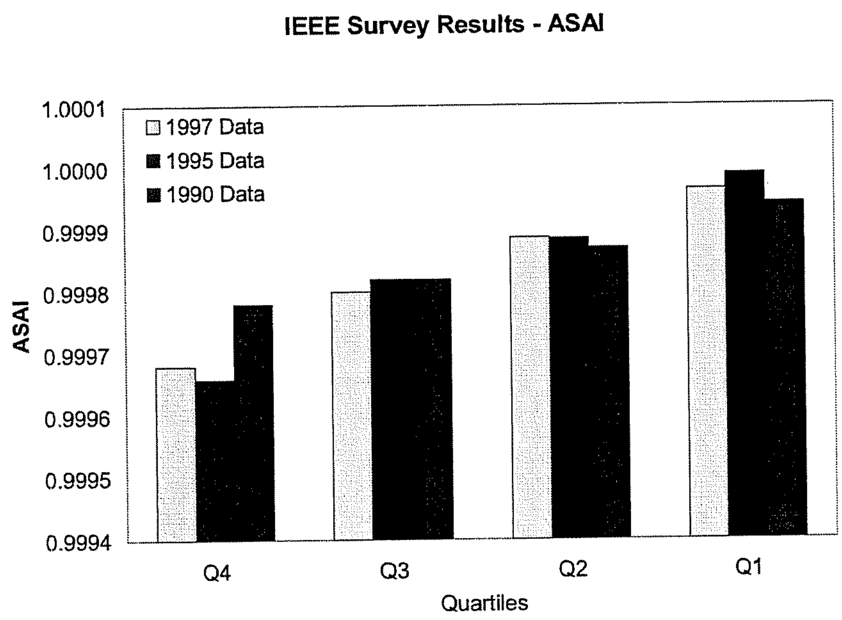


Figure A.7—ASAI– 1990, 1995, and 1997 survey results [B1] and [B11]

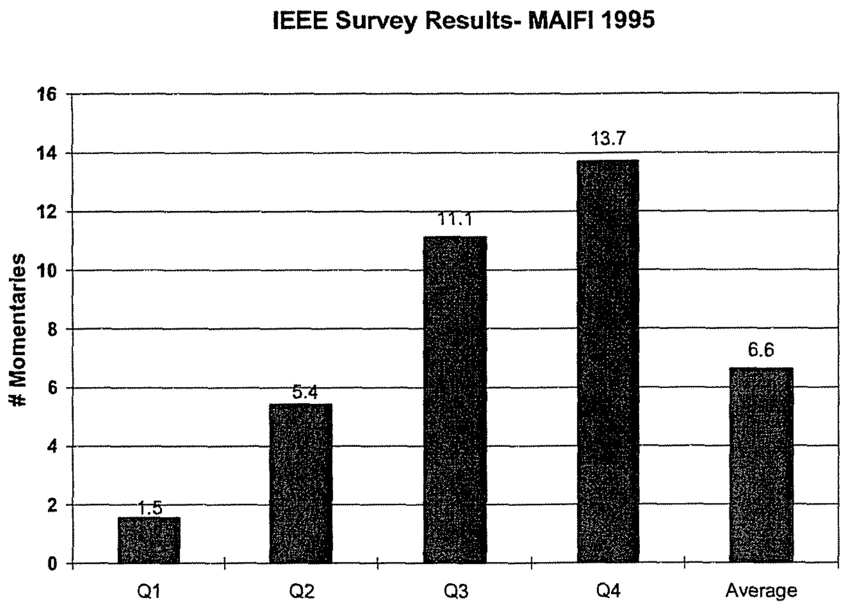


Figure A.8—MAIFIQ– 1995 survey results (1990/7 data not available) [B1]

A.1 Cause codes

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

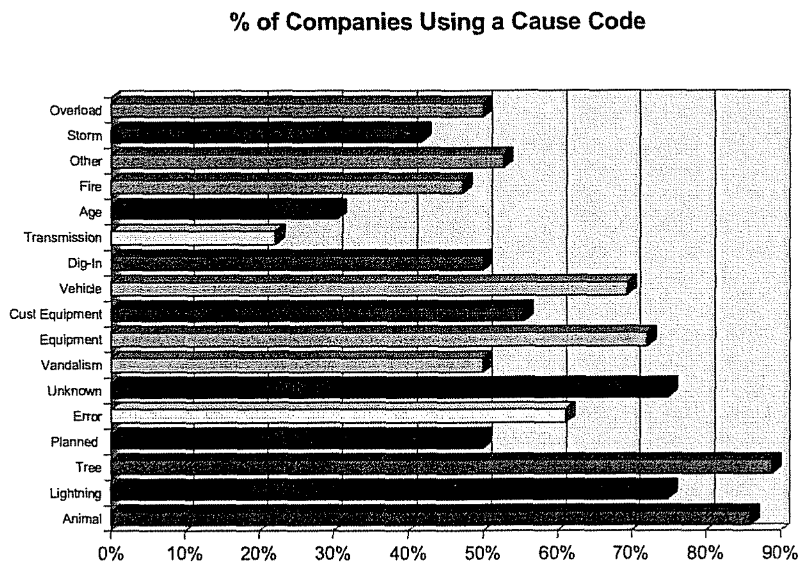


Figure A.9—1997 Cause code usage 1

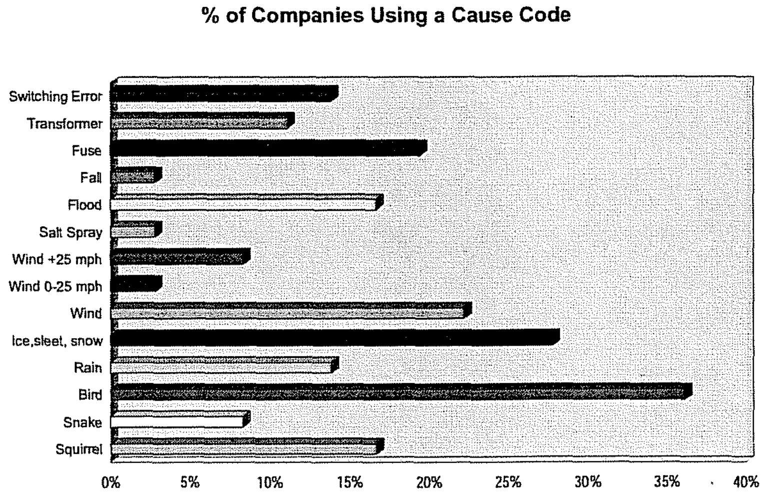


Figure A.10—1997 Cause code usage 2

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 the effects of changes in reliability practices in the reported results, and also to limit the amount of data which must be archived.

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 2.5β method of identifying MEDs in distribution reliability data. The 2.5β 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).

$$p(\text{ SAIDI} > T) = \int_{T}^{\infty} pdf(\text{ SAIDI})d\text{SAIDI} \tag{B.1}$$

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

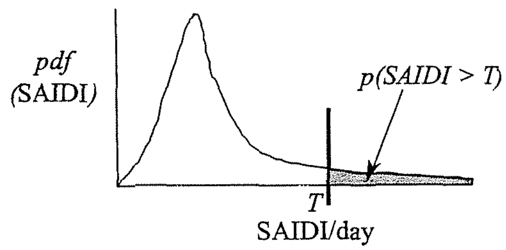


Figure B.1—The area under the probability density function *pdf* (SAIDI) above threshold (T) is the probability *p* that a given day will have a SAIDI value greater than (T)

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.

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

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.

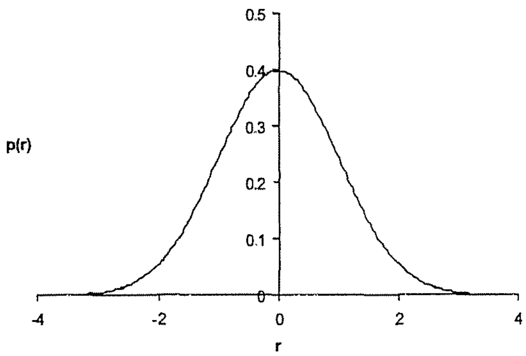


Figure B.2—Gaussian or normal probability distribution

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.

$$T_{MED} = \mu + n\sigma \tag{B.3}$$

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.

Table B.1—Probability of exceeding a threshold for the Gaussian distribution

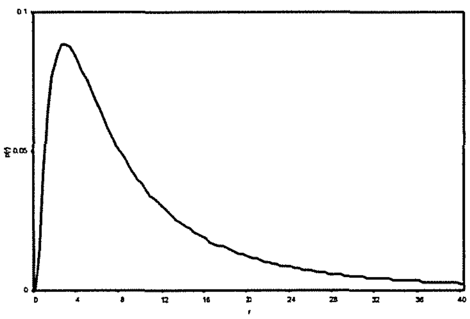
k	p
1	0.15866
2	0.02275
3	0.00135
6	9.9×10^{-10}

B.4.3 Three sigma

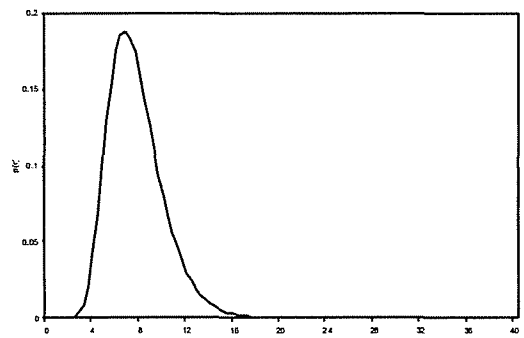
The term "Three Sigma" is often used loosely to designate a rare event. It comes from the Gaussian probability distribution. As Table B.1 shows, the probability of exceeding a threshold that is three standard deviations more than the mean is 0.00135, or one and a half tenths of a percent. If daily SAIDI 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 $-\infty$ 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.



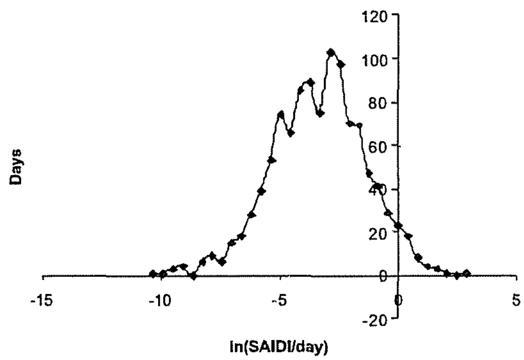
(a)



(b)

(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 β, or Beta, then α and β 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 α and β. Equations (B.4) and (B.5) show these concepts mathematically.

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

and

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

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*.

Table B.2—Probability of exceeding T_{MED} as a function of multiples of BETA

k	*p*	MEDs/yr
1	0.15866	57.9
2	0.02275	8.3
2.4	0.00822	3.0
2.5	0.00621	2.3
3	0.00135	0.5
6	9.9×10^{-10}	3.6E- 07

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).

$$p_{f\backslash m,\,k,\,n} = \frac{k}{n+k-f}\frac{\binom{m}{k}\binom{n}{f}}{\binom{n+m}{n+k-f}} \tag{B.5}$$

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.

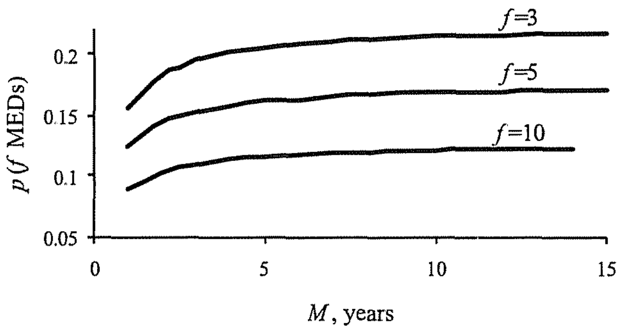


Figure B.5—Probability of exactly new MEDs in the next year of data, using *M* years of historical data

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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