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HAND DELIVERED

James A. Welch
Director of Engineering
Public Service Commission of Kentucky
211 Sower Boulevard
Frankfort, Kentucky   40601

RE: **Kentucky Power Company Distribution Vegetation Management Plan**

Dear Mr. Welch:

Enclosed please find Kentucky Power Company's filing in response to the Commission's October 26, 2006 Order in Case No. 2006-00494.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

16393:2:FRANKFORT

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COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

AN INVESTIGATION OF THE RELIABIITY)	
MEASURES OF KENTUCKY'S JURISDICTIONAL)	
ELECTRIC DISTRIBUTION UTILITIES AND)	CASE NO. 2006-00494
CERTAIN RELIABIITY MAINTENANCE PRACTICES)	

KENTUCKY POWER COMPANY

RESPONSES TO COMMISSION ORDER DATED OCTOBER 26, 2007

April 1, 2008

Kentucky Power Company

REQUEST

On a system-wide basis, provide on a calendar year (January to December) the System Average Interruption Frequency Index (SAIFI), the System Average Interruption Duration Index (SAIDI), and the Customer Average Interruption Duration Index (CAIDI):

(a)   provide information separately for calendar years 2003 through 2007,

(b)   calculated on system-wide level, using IEEE Std. 1366 guide (latest version) to define the terms used in the report, exclude Major Events, and

(c)   durations of outages measured and reported in minutes.

RESPONSE

Calculated values for each index for each of the past 5 calendar years are listed on the attached page (see Attachment A). Also, pursuant to the Commission's Order dated October 26, 2007 in Case No. 2006-00494, a copy of the current version of IEEE Std 1366-2003 is attached (see Attachment B). It should be noted that this is copyrighted material; so further use may be restricted.

WITNESS: Everett G Phillips

Kentucky Power Company

5 Year System Performance

(Excluding IEEE-defined Major Events)

Calendar Year	SAIFI	CAIDI	SAIDI
2003	2.360	236.6	558.2
2004	2.545	204.5	520.5
2005	2.576	159.3	410.4
2006	2.757	182.2	502.1
2007	2.276	146.9	334.2

1366™

IEEE Guide for Electric Power Distribution Reliability Indices

IEEE Power Engineering Society

Sponsored by the
Transmission and Distribution Committee

◆IEEE

Recognized as an
American National Standard (ANSI)

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

IEEE Guide for Electric Power Distribution Reliability Indices

Sponsor

Transmission and Distribution Committee
of the
IEEE Power Engineering Society

Approved 26 April 2004
American National Standards Institute

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.

Patents

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Interpretations

Current interpretations can be accessed at the following URL: http://standards.ieee.org/reading/ieee/interp/index.html.

Participants

At the time this standard was completed, the Working Group on System Design had the following membership:

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Acknowledgments

The following members were primary authors and data analyzers for the development of the 2.5 Beta Methodology that is used for identification of major event days:

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v

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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.

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[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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Pursuant to PSC's October 26, 2007 Order in Case No. 2006-00494
Item No. 1, Attachment B
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IEEE GUIDE FOR ELECTRIC POWER DISTRIBUTION RELIABILITY INDICES

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.

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

Pursuant to PSC's October 26, 2007 Order in Case No. 2006-00494
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IEEE GUIDE FOR ELECTRIC POWER DISTRIBUTION RELIABILITY INDICES

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).

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

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

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

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).

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

To calculate the index, use Equation (4).

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

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).

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

To calculate the index, use Equation 6.

$$CAIDI = \frac{\sum r_i N_i}{\sum N_i} = \frac{SAIDI}{SAIFI} \qquad (6)$$

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).

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

To calculate the index, use Equation (8).

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

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).

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

To calculate the index, use Equation (10)

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

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).

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

To calculate the index, use Equation (12).

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

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).

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

To calculate the index, use Equation (14).

$$CEMI_n = \frac{CN_{(k > n)}}{N_T} \tag{14}$$

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.

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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).

$$\text{MAIFI} = \frac{\sum \text{IM}_i N_{mi}}{N_T} \tag{20}$$

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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).

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

To calculate the index, use Equation (22).

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

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).

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

To calculate the index, use Equation (24).

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

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:

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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).				

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

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).

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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.

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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

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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.

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

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

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

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

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

$CTAIDI$, $CAIFI$, $CEMI_n$, 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 $CN(k > n)$, 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).
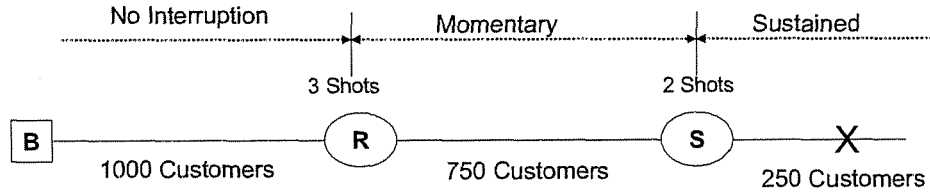
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Figure 1—Sample system 2

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.

$$SAIFI = \frac{250}{2000} = 0.125 \tag{41}$$

$$MAIFI = \frac{2 \times 750}{2000} = 0.75 \tag{42}$$

$$MAIFI_E = \frac{1 \times 750}{2000} = 0.375 \tag{43}$$

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.
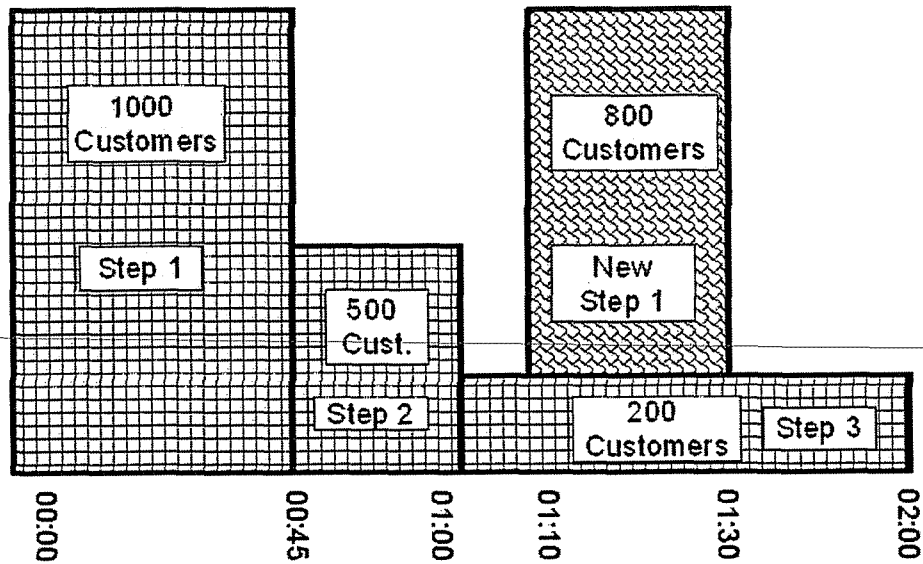

Figure 2—Step restoration time chart

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.

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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.
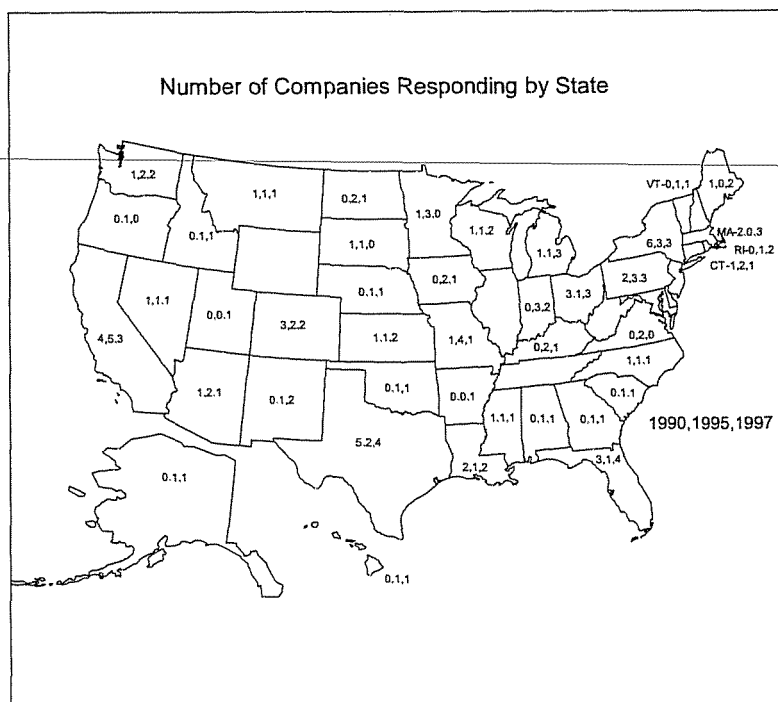

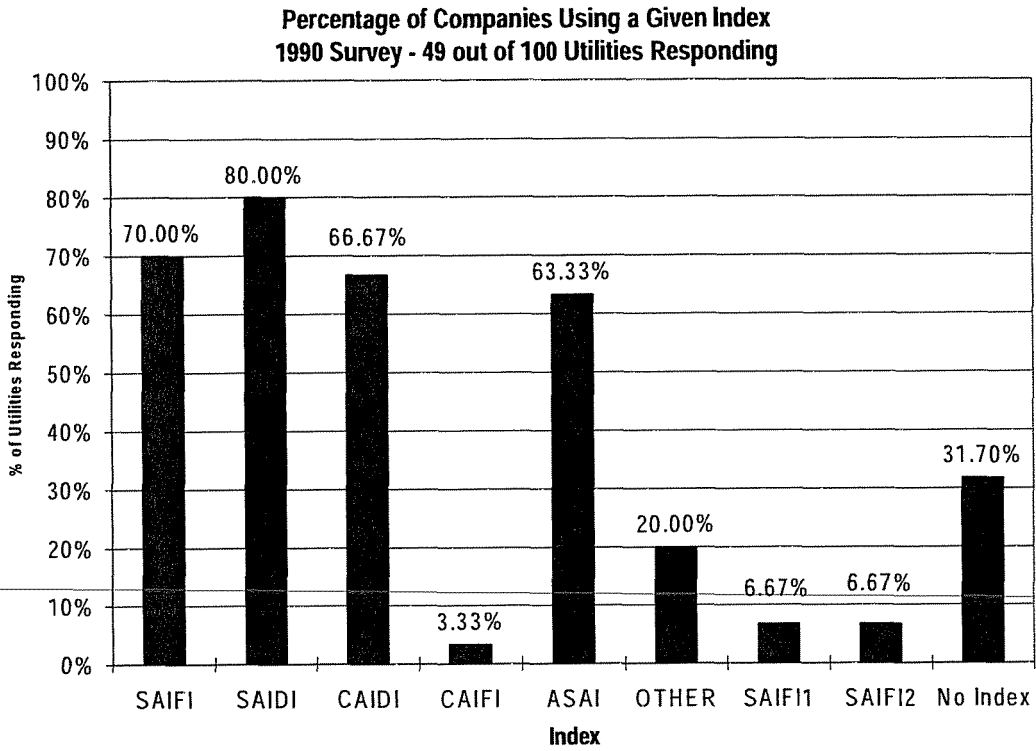**Figure A.1—Location of companies that respond to surveys**

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

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Percentage of Companies Using a Given Index
1990 Survey - 49 out of 100 Utilities Responding

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

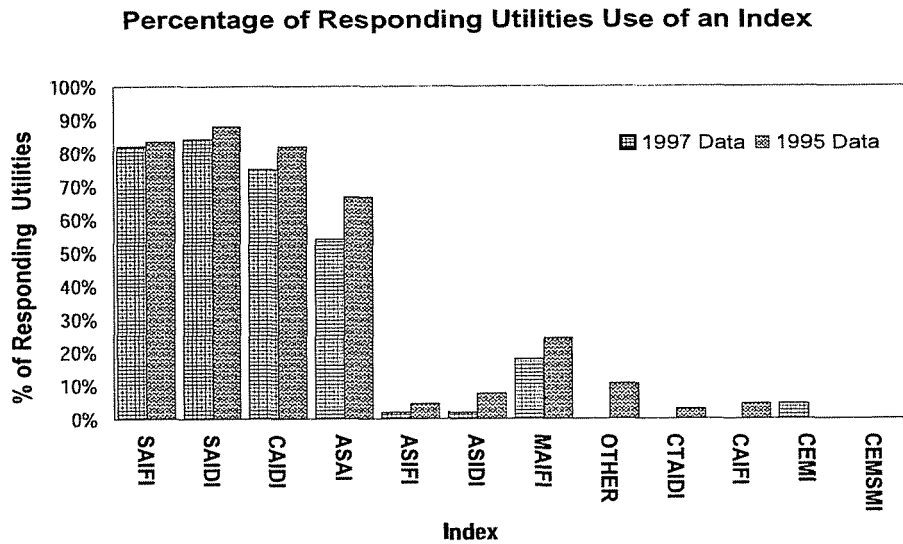**Percentage of Responding Utilities Use of an Index**

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

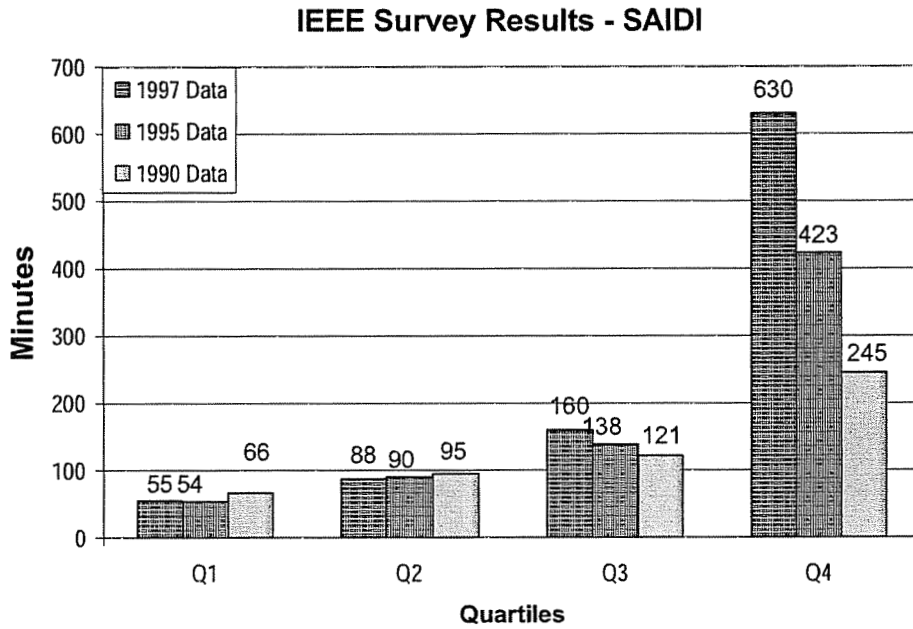## IEEE Survey Results for SAIFI
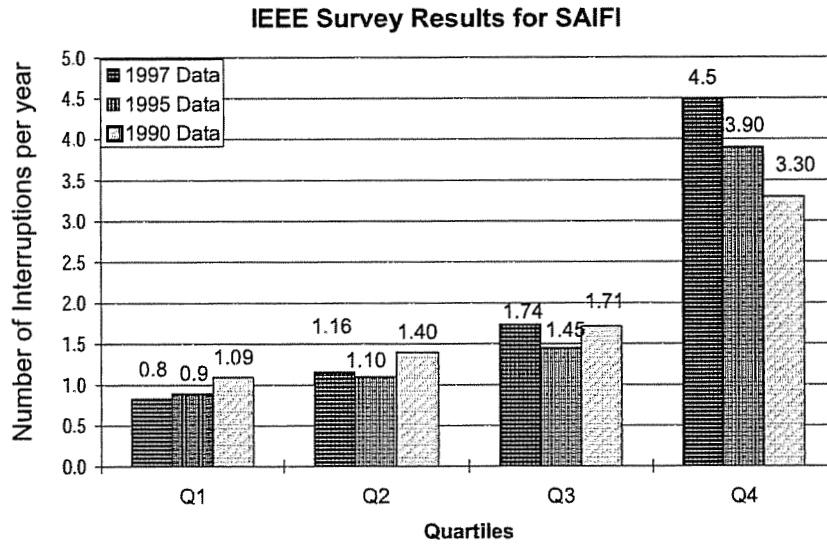
Figure A.4—SAIFI– 1990, 1995 and 1997 survey results [B1] and [B11]

IEEE Survey Results - SAIDI

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

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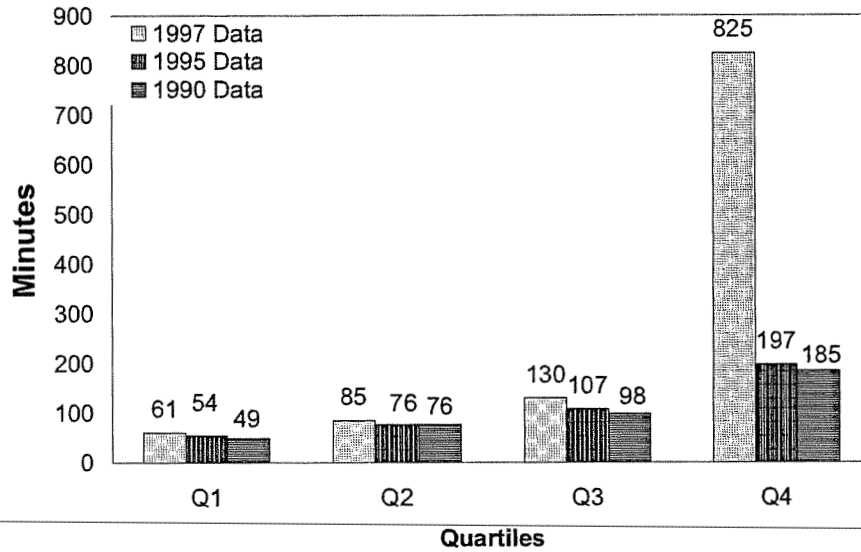
IEEE Survey Results - CAIDI

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

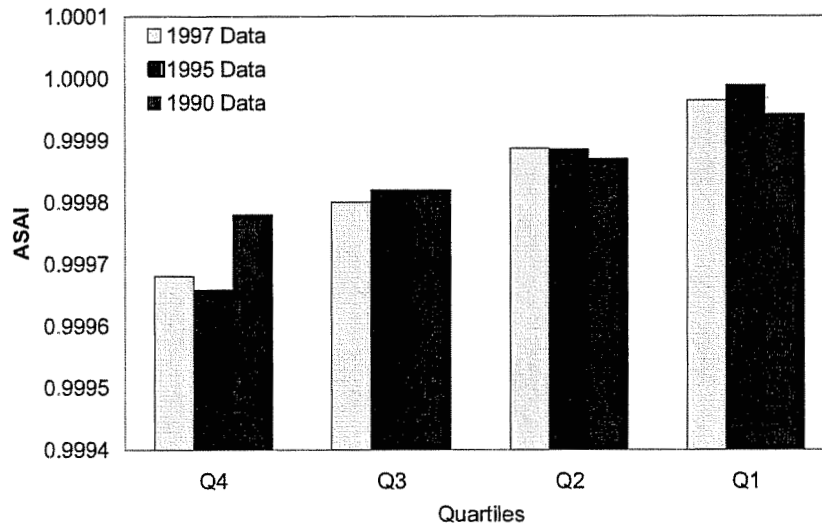## IEEE Survey Results - ASAI

Figure A.7—ASAI– 1990, 1995, and 1997 survey results [B1] and [B11]
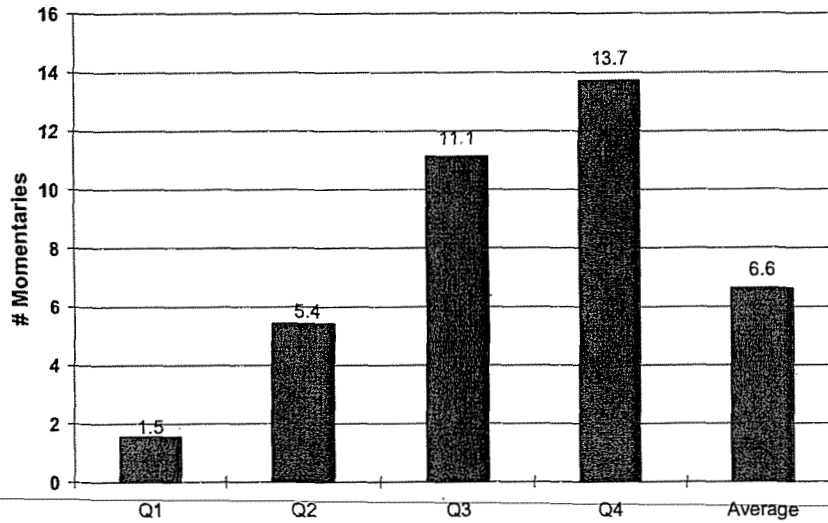
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IEEE Survey Results- MAIFI 1995

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.

% of Companies Using a Cause Code

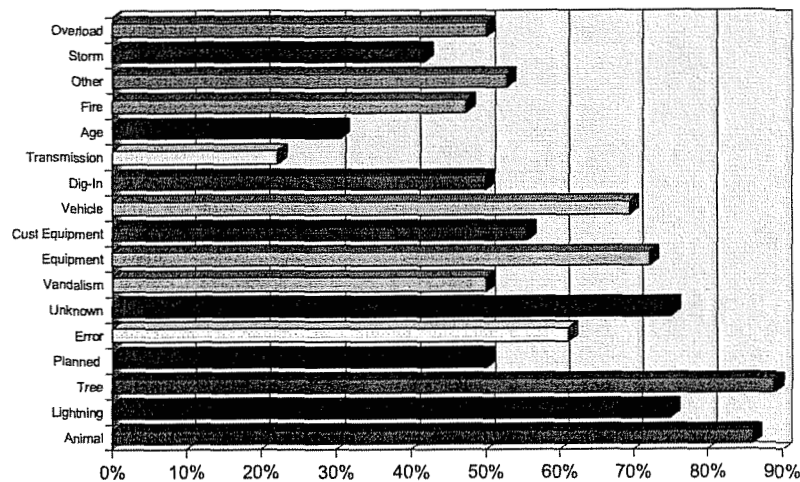**Figure A.9—1997 Cause code usage 1**
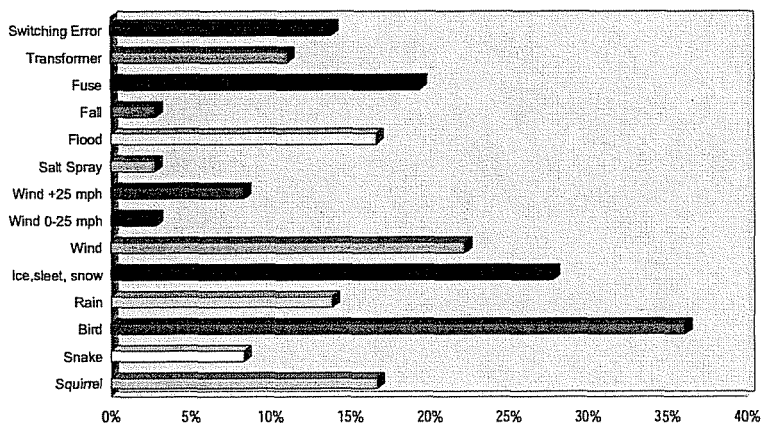
% of Companies Using a Cause Code

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.

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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.

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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.

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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

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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)

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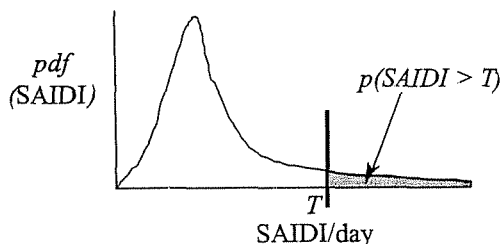
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**Figure B.1—The area under the probability density function *pdf* (SAIDI)
above threshold (T) is the probability *p* that a given day will have a
SAIDI value greater than (T)**

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.

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

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.
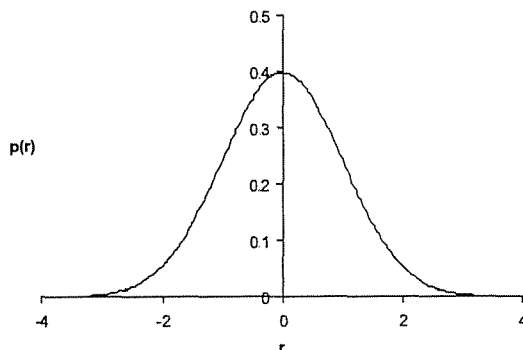

Figure B.2—Gaussian or normal probability distribution

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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.

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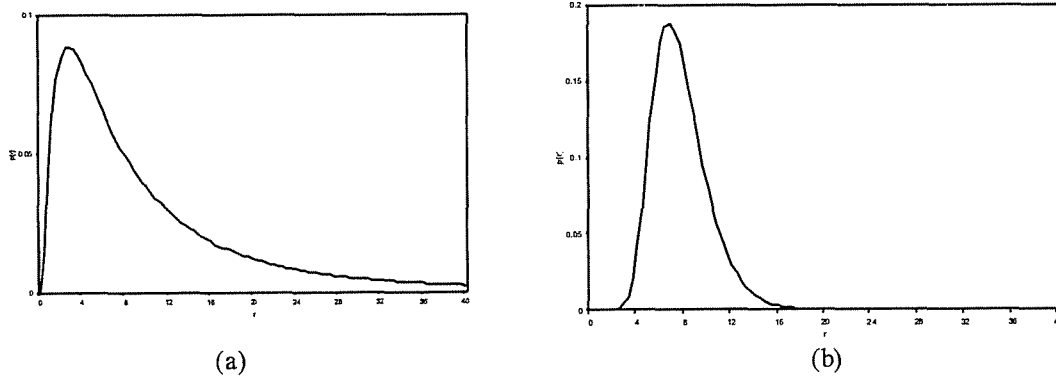
(a) Less than standard deviation.
(b) Greater than standard deviation.

Figure B.3—Log-normal distributions
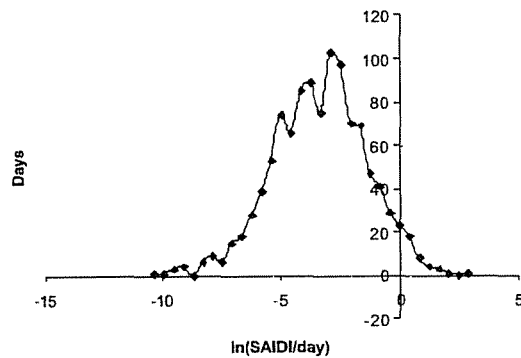
This indicates three years of daily SAIDI data from anonymous
Utility 2 supplied by the Distribution System Design Working
Group. The logs of the data are normally distributed, so the daily
data is log-normally distributed.

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 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 α and ß. Equations (B.4) and (B.5) show these concepts mathematically.

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

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.

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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 kth largest value in m samples will be exceeded f times in n future samples [B10]. It is given in Equation (B.5).

$$P_{f \backslash m, k, n} = \frac{k}{n+k-f} \frac{\binom{m}{k}\binom{n}{f}}{\binom{n+m}{n+k-f}}$$

(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.
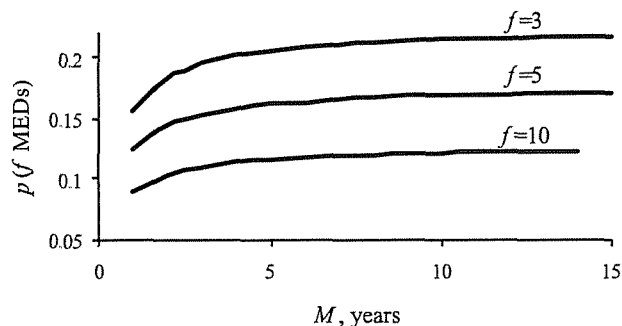

Figure B.5—Probability of exactly new MEDs in the next year of data, using *M* years of historical data

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.

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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.

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IEEE GUIDE FOR ELECTRIC POWER DISTRIBUTION RELIABILITY INDICES

Annex D

(informative)

Bibliography

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[B10] Kottegoda N. T., and Rosso R., Statistics, Probability, and Reliability for Civil and Environmental Engineers, McGraw-Hill, New York, 1997.

[B11] Marinello, C. A., "A Nationwide Survey of Reliability Practices," presented at EEI Transaction and Distribution Committee Meeting, Hershey, PA, October 20, 1993.

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[4]Available on request from christie@ee.washington.edu.
[5]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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REQUEST

For each index, provide an analysis of the contributing causes for the reporting year 2007:

(a)   list the ten most significant outage cause categories, and

(b)   the value each category contributed to the final index value.

RESPONSE

The Top Ten Outage Causes for each of the 3 major reliability indices (SAIFI, SAIDI and CAIDI) are listed on the attached pages. The value each category contributed to the final index value was a straight-forward calculation for SAIFI and SAIDI since there is only one variable involved in each of these indices. However, since CAIDI is derived from two variables, Customers Interrupted (CI) and Customer Minutes Interrupted (CMI), it was not immediately obvious how to rank the various outage causes for CAIDI. Merely listing the highest calculated CAIDI values for each individual cause produced a list that included isolated cause categories with few outages and few customers interrupted. Therefore, we chose to calculate the "percent contribution" for CAIDI outage causes by averaging the percentage of Customers Interrupted and the percentage of Customer Minutes Interrupted for each outage category. We then ranked these percent contributions to reflect the CAIDI values of the most significant outage categories.

WITNESS: Everett G Phillips

Kentucky Power Company

2007 Top Ten Outage Causes - SAIFI

(Excluding IEEE-defined Major Events)

#	Cause Description	SAIFI	Percent Contribution
1	EQUIPMENT FAILURE	0.492	21.64%
2	VEGETATION OUTSIDE R/W	0.488	21.45%
3	VEGETATION INSIDE R/W	0.264	11.61%
4	SCHEDULED	0.233	10.24%
5	TRANSMISSION	0.138	6.07%
6	STATION - DISTRIBUTION	0.110	4.82%
7	UNKNOWN (NON-WEATHER)	0.090	3.97%
8	VEHICLE ACCIDENT	0.074	3.26%
9	TREE REMOVAL (NON AEP)	0.065	2.84%
10	LIGHTNING	0.063	2.75%
	Total for Top Ten Outage Causes	2.017	88.65%
	Total for All Outage Causes	2.276	100.00%

Kentucky Power Company

2007 Top Ten Outage Causes - CAIDI

(Excluding IEEE-defined Major Events)

#	Cause Description	CAIDI	Percent Contribution *
1	VEGETATION OUTSIDE R/W	214.9	26.42%
2	EQUIPMENT FAILURE	131.6	20.51%
3	VEGETATION INSIDE R/W	166.7	12.40%
4	SCHEDULED	89.1	8.23%
5	TRANSMISSION	144.0	6.01%
6	STATION - DISTRIBUTION	106.8	4.16%
7	UNKNOWN (NON-WEATHER)	92.8	3.24%
8	VEHICLE ACCIDENT	127.5	3.04%
9	LIGHTNING	173.1	3.00%
10	TREE REMOVAL (NON-AEP)	107.4	2.45%
	Total for Top Ten Outage Causes	149.6	89.47%
	Total for All Outage Causes	146.9	100.00%

*   Calculated by averaging the percentage of Customers Interrupted and the percentage
of Customer Minutes Interrupted for each Outage Category

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2007 Top Ten Outage Causes - SAIDI

(Excluding IEEE-defined Major Events)

#	Cause Description	SAIDI	Percent Contribution
1	VEGETATION OUTSIDE R/W	104.9	31.39%
2	EQUIPMENT FAILURE	64.8	19.39%
3	VEGETATION INSIDE R/W	44.1	13.19%
4	SCHEDULED	20.8	6.21%
5	TRANSMISSION	19.9	5.95%
6	STATION - DISTRIBUTION	11.7	3.50%
7	LIGHTNING	10.8	3.24%
8	VEHICLE ACCIDENT	9.5	2.83%
9	UNKNOWN (NON WEATHER)	8.4	2.51%
10	TREE REMOVAL (NON AEP)	6.9	2.07%
	Total for Top Ten Outage Causes	301.7	90.29%
	Total for All Outage Causes	334.2	100.00%

Kentucky Power Company

REQUEST

Provide a list of the ten worst performing circuits for the reporting year 2007 for each index value. For each of the circuits provide the following:

(a)   identification of the circuit,
(b)   the index value calculated for the circuit,
(c)   major outage category contributing to circuit's performance,
(d)   an analysis of the cause of poorer performance, and
(e)   corrective actions taken or planned to improve performance.

RESPONSE

The Worst Performing Circuits for 2007 are described and explained in Attachment A. An analysis of the cause of poorer performance and corrective action plan is provided for each of Kentucky Power's service areas: Ashland District (Attachment B), Hazard District (Attachment C), and Pikeville District (Attachment D).

WITNESS: Everett G Phillips

Kentucky Power Company

2007 Worst Performing Circuits

Ranked by **SAIFI** Index

	Identification of Circuits				Performance Data	
Rank	District	Circuit #	Station Desc	Circuit Desc	Circuit SAIFI	Major Outage Category
1	Pikeville	3411401	DEWEY	INEZ	9.001	Equipment Failure
2	Pikeville	3408303	COLEMAN	PETER CREEK	7.599	Tree Inside ROW
3	Pikeville	3411801	JOHNS CREEK	META	7.339	Equipment Failure
4	Pikeville	3202202	LOVELY	WOLF CREEK	7.141	Tree Out of ROW
5	Hazard	3308001	JACKSON	SO JACKSON	6.753	Error - Field
6	Hazard	3303901	LESLIE	HYDEN	6.687	Equipment Failure
7	Pikeville	3413401	GARRETT	GARRETT	6.287	Equipment Failure
8	Hazard	3309301	VICCO	REDFOX	5.499	Equipment Failure
9	Hazard	3310501	HADDIX	QUICKSAND	5.493	Equipment Failure
10	Hazard	3303902	LESLIE	WOOTON	5.196	Error - Field

Notes: Covers period from January 1, 2007 through December 31, 2007
Based on IEEE Standard 1366-2003
Excludes Jurisdictional Major Event Days

Kentucky Power Company

2007 Worst Performing Circuits

Ranked by **CAIDI** Index

Rank		Identification of Circuits			Performance Data	
	District	Circuit #	Station Desc	Circuit Desc	Circuit CAIDI	Major Outage Category
1	Pikeville	2970603	HURLEY	RACEFORK	865.6	Scheduled Company
2	Ashland	3001102	HOODS CREEK	RURAL	643.4	Tree Inside ROW
3	Pikeville	3404002	SPRINGFORK	1PHASEDIST	614.5	Tree Out of ROW
4	Pikeville	3407101	TOPMOST	DEMA	462.4	Weather - Flood/Slide
5	Ashland	3000302	BELLEFONTE	FLATWOODS	330.3	Equipment Failure
6	Ashland	3001202	HOWARD COLLINS	29STREET	322.9	Tree Inside ROW
7	Ashland	3000802	HAYWARD	LAWTON	305.4	Tree Inside ROW
8	Pikeville	3451201	BEEFHIDE	BEEFHIDE	305.4	Tree Out of ROW
9	Ashland	3002106	TENTH STREET	FRONT STREET	302.1	Equipment Failure
10	Ashland	3117602	PRINCESS	ROUTE 180	298.6	Weather - Unknown

Notes: Covers period from January 1, 2007 through December 31, 2007
Based on IEEE Standard 1366-2003
Excludes Jurisdictional Major Event Days

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2007 Worst Performing Circuits

Ranked by **SAIDI** Index

	Identification of Circuits			Performance Data	
Rank	**District**	**Circuit #**	**Station Desc**	**Circuit Desc**	**Circuit SAIDI**	**Major Outage Category**
1	Pikeville	3404002	SPRINGFORK	1PHASEDIST	2744.8	Tree Out of ROW
2	Pikeville	3411401	DEWEY	INEZ	1505.2	Tree Out of ROW
3	Hazard	3309301	VICCO	REDFOX	1297.3	Tree Inside ROW
4	Ashland	3003703	COALTON	TRACE CREEK	1261.4	Tree Out of ROW
5	Pikeville	3411801	JOHNSCREEK	META	1189.7	Weather – Lightning
6	Hazard	3309001	JEFF	VIPER	1171.3	Tree Out of ROW
7	Pikeville	3409502	BURDINE	LEVISA	1049.2	Tree Inside ROW
8	Pikeville	3202202	LOVELY	WOLF CREEK	964.6	Tree Out of ROW
9	Hazard	3303901	LESLIE	HYDEN	933.0	Tree Out of ROW
10	Hazard	3310501	HADDIX	QUICKSAND	843.7	Equipment Failure

Notes: Covers period from January 1, 2007 through December 31, 2007
Based on IEEE Standard 1366-2003
Excludes Jurisdictional Major Event Days

Kentucky Power Company

2007 WORST PERFORMING CIRCUITS

Analysis of Causes/Corrective Actions

Ashland District

Hoods Creek Station – Rural 12kV Circuit (3001102 – CAIDI # 2)

Ashland District experienced an IEEE-defined Major Event caused by high winds and lightning on August 16, 2007. Even though only the one day qualified as a Major Event, effects of the storm continued up through August 19, 2007 causing additional outages. There were four outages that were included in the Major Event for this circuit. However, three additional outages occurred on August 17, 2007 that accounted for 57.5% of CMI for this circuit and were not included in the Major Event. One of the three outages had a large CMI as it affected 91 customers due to Tree Inside ROW. Restoration efforts were hampered due limited resources caused by the Major Event on the prior day. Tree Inside ROW was addressed before customers were restored.

On April 15, 2007, heavy rains during a spring storm caused flooding in the area. Crews were unable to get to poles due to the high water. This outage lasted over 25 hours. An additional line was constructed that will allow us to feed a portion of the customers from another direction in the event that this was to happen again. Forestry addressed some "hotspot" issues following recent windstorms in early 2008. This circuit is also scheduled to be ground sprayed with a basal application in 2008.

Bellefonte Station – Flatwoods 12kV Circuit (3000302 – CAIDI #5)

This circuit experienced 4 outages during the entire year. On June 27, 2007 a Tree Inside ROW caused an outage that lasted approximately 17 hours. This accounted for 68.7% of CMI for this circuit. Step restoration was performed in order to restore all but 10 customers. Location was inaccessible and four tree crews cleared R/W. Data shows that Cannonsburg area had 37 cases of trouble for this date which may have also lengthened the outage.

No further action is required at this time.

Howard Collins Station – 29th Street 12kV Circuit (3001202 – CAIDI #6)

Ashland District experienced an IEEE-defined Major Event caused by high winds and lightning on August 16, 2007. Even though only the one day qualified as a Major Event, effects of the storm continued up through August 19, 2007 causing additional outages. There were seven outages that were included in the Major Event for this circuit. However, two additional outages (Tree Inside ROW) occurred on August 19, 2007 that accounted for 69.3% of CMI for this circuit and was not included in the Major Event. Restoration efforts were hampered due limited resources caused by the Major Event on the prior day. Tree Inside ROW was addressed before customers were restored. If these two outages were removed from the data CAIDI would have dropped from 322.9 minutes to 121.2 minutes.

No further action required.

Hayward Station – Lawton 12kV Circuit (3000802 – CAIDI #7)

At Pole #38830271C24005, recloser cleared two outages (Tree Inside ROW and Tree Outside ROW) that accounted for 57.5% of CMI. If these two outages were taken out of the data the CAIDI would have dropped from 305.4 minutes to 209.0 minutes.

Forestry will inspect this lateral to see if any further work can be completed in advance to minimize future outages. Also, engineering will look into additional sectionalizing on tap.

Tenth Street Station – Front Street 12kV Circuit (3002106 – CAIDI #9)

On February 7, 2007 an outage occurred when a transmission static wire fell into this distribution circuit. This accounted for 83% of the CMI for this circuit. Fault was isolated and 104 of the 109 customers were restored. The remaining 5 customers experienced approximately 16.5 hour outage. This outage was lengthened as an insulator failed and burnt a transmission crossarm. Only five total outages occurred on this circuit in 2007 and the other four outages were all less than 250 minutes in duration.

No further action planned.

Princess Station – Route 180 34.5kV Circuit (3117602 – CAIDI #10)

Circuit experienced four lightning outages and one weather – unknown outage. Two of the four lightning outages occurred on June 13, 2007 and both lasted longer than 10 hours. Ashland area had a storms roll through the area and experienced 37 outages on June 13, 2007. Had one outage due to equipment failure that lasted for nearly 19 hours. Two customers were affected, one residential and one service to a barn. Once service was restored to residence, customer agreed to allow the service to the barn to be repaired the following day.

Engineering will investigate the possibility of adding lightning mitigation, especially in the station zone. Plan to investigate the use of current limiting fuses on transformers on this circuit.

Coalton Station – Trace Creek 12kV Circuit (3003703 – SAIDI #4)

Approximately 85% of the CMI for this circuit was due to Tree Out of ROW and Equipment Failure outages. Approximately 95% of the CMI for Tree Out of ROW was due to the outage on April 1, 2007. Tree fell on three phase breaking top of pole and a crossarm on an adjacent pole. The broken pole and crossarm were inaccessible and the crew requested that a bulldozer cut a road back to the location. Approximately 90% of the CMI for Equipment Failure was due to the outage on January 26, 2007. A cutout on a transformer failed and burnt pole. We experienced cold load pick-up problems trying to restore customers.

A full circuit trim is planned for this circuit and will start in early spring. Expect this to be completed in 2 years. Also, a walking inspection/repair has begun utilizing a 4 man crew. Expect the inspection/repairs to be completed during 2008.

Kentucky Power Company

2007 WORST PERFORMING CIRCUITS

Analysis of Causes/Corrective Actions

Hazard District

Haddix Station – Quicksand 34.5kV Circuit (3310501 – SAIFI #9, SAIDI#10)

This circuit has been at or near the top of our worst performing circuit list for several years and as such has been the focus of targeted reliability improvements. Because of the size of this circuit (259 line miles) and the number of customers served (over 2200) any outage on the feeder breaker or first zone reclosers will result in a high number of customer minutes of interruption (CMI). There have been intensive r/w reclearing, spraying and widening efforts over the past several years including considerable use of an aerial saw. There has also been an effort to repair or replace defective equipment on this circuit. In 2007, 47 poles were replaced with 5 being replaced so far in 2008. In 2006, 170 line cutouts were replaced, followed with 148 cutouts being replaced in 2007. Also in 2007, all six main three phase line reclosers were replaced with electronic types for better circuit coordination and to provide event recording.

Although tree related causes resulted in 20% of the total CMI for 2007, only 3% was due to trees from within the r/w. This reflects the improved r/w conditions on this circuit. There will be additional r/w widening at selected locations in the feeder breaker zone in 2008. One feeder breaker outage due to a pole fire accounted for 33% of total CMI in 2007. This was caused by a cutout failure. The cutout replacement program is an attempt to prevent/reduce this type of outage.

Including the feeder zone pole fire, equipment failures of all types resulted in 52% of the total CMI on this circuit. A detailed pole-by-pole inspection is underway to identify any additional defective equipment. The inspection is approximately 33% complete and repairs are planned to be completed in 2008.

Jackson Station – South Jackson 12kV Circuit (3308001 – SAIFI #5)

This circuit was experiencing an increasing number of primary conductor failures in 2005 and 2006. The main backbone of this circuit was 1960's era 15kV spacer cable and the polymer covering was deteriorating. The internal aluminum conductor was being eroded away at openings in the polymer covering particularly at porcelain spacers and pin insulators. A capital improvement project was prepared to replace all the 15kV spacer cable with cross arm mounted bare aluminum and aluminum alloy conductor. This work was completed in the fall of 2007.

There were five complete circuit outages that accounted for 77% of all of the CMI in 2007. These also contributed 5.0 to the overall SAIFI of 6.7 for this circuit for 2007. Two of the circuit outages resulted from new conductor pulling operations associated with the spacer cable replacement project. One was due to a direct lightning strike to the circuit near Jackson Station during a severe lightning storm. One was due to a station voltage regulator failure (subsequently replaced). One was due to a subtransmission line outage caused by a tree falling from outside the 69kV line r/w on the southern feed of Jackson Station. A subsequent relay failure on the northern feed of Jackson Station resulted in a total loss of subtransmission feed to Jackson Station. Subtransmission service was restored manually and the relay problem was promptly corrected.

Three of the circuit outages (the regulator failure, the lightning strike and the subtransmission outage) are the type of event that are unlikely to occur again. With the completion of the circuit reconductoring, it is expected that the reliability of this circuit will be improved in 2008.

Jeff Station - Viper 12kV Circuit (3309001 – SAIDI #6)

This circuit experienced three complete feeder outages that accounted for 74% of the CMI in 2007. One particularly long feeder outage (627 minutes) was caused by a large tree that fell from outside the r/w that broke three poles in the breaker zone. This one outage alone accounted for 57% of the CMI. Two other feeder outages that accounted for 17% of the CMI were caused by a contractor felling trees onto the conductor in the breaker zone. This contractor was clearing r/w for a major highway relocation project that followed the path of the circuit. A large portion of this circuit was relocated in 2006 to accommodate the highway project. One scheduled outage accounted for another 17% of the CMI. This scheduled outage (254 minutes) was required to replace a bad pole that was in an inaccessible location.

The r/w in the breaker zone was widened in 2007 to reduce the threat from trees from outside the r/w. This work was completed along a steep hillside above the feeder. Additional r/w clearing was completed along the route of the highway relocation. With this r/w work accomplished and the highway clearing work completed, it is expected that the reliability for this circuit will be improved in 2008.

Leslie Station - Hyden 34.5kV Circuit (3303901 – SAIFI #6, SAIDI #9)

This circuit is another of our worst performers that is a large circuit with 124 line miles serving 1360 customers. There has been significant r/w reclearing work on this circuit over the past few years. Although tree related causes contributed to 40% of the total CMI in 2007, only 4% of the total CMI was due to trees in the r/w. That leaves 36% of the total CMI due to trees from outside the r/w. Equipment failures contributed to 28% of the total CMI in 2007 with 20% attributed to only two separate events. One was due to an insulator failure in the breaker protection zone and the other was due to a splice failure on a large three phase tap. This is one of the circuits designated by local management to be targeted to reduce outages caused by equipment failures. A detailed pole-by-pole inspection is underway to identify any additional defective equipment. The inspection is approximately 90% complete and repairs are planned to be completed in 2008.

In 2007 a large capital improvement project, established the new Stinnett Station - Wendover 34.5kV Circuit. Approximately 14 miles of primary line with 368 customers were transferred to this new circuit from the Hyden Circuit.

Leslie Station - Wooton 34.5kV Circuit (3303902 – SAIFI #10)

This is a large circuit with 133 line miles serving 1859 customers. This circuit has historically been one of our worst performers. Of the total CMI in 2007, 23% was due to trees in the r/w and 21% was due to trees outside the r/w for a total of 44%. This circuit was targeted for a total circuit r/w reclear in 2007. The aerial saw was used to widen existing r/w and to cut difficult to access overhanging limbs. There were several outages caused by the aerial saw activities which added up to 19% of the total CMI in 2007. Considering the three causes (trees in, trees out and the aerial saw), vegetation management/tree causes resulted in 63% of the total CMI.

The r/w reclearing work is on going in 2008 and selected sections of the circuit will be targeted for widening of the r/w. As the r/w maintenance work is completed, we expect the reliability of this circuit to improve.

Vicco Station - Redfox 34.5kV Circuit (3309301 – SAIFI #8, SAIDI #3)

During 2007, this circuit had total customer minutes of interruption (CMI) of 745,927. Two events accounted for 55% of these minutes. One outage on 7/11/2007 was caused by a combination of events. A tree fell onto an unfused tap off of the main three phase line beyond the first line recloser. The main feeder breaker failed which caused the station to trip out. Restoration was attempted from the other feeder breaker and it also locked out. The main line recloser was also suspected to have failed. After the tap was isolated, the main feeder breaker repaired and the recloser was bypassed, the feeder was restored to service. The recloser was replaced. This one event was responsible for 39% of the circuit CMI. Another event caused by a broken pole during a storm was responsible for 16% of the circuit CMI. This was in a difficult location across Carr Fork Lake.

There is a large project scheduled for this circuit in 2008 that is required to serve increased load for a coal company. Approximately, 19kFT of the main feeder will be upgraded from 1/0AA conductor to 4/0AA conductor, including replacement of cross arms and insulators. There will be some right of way reclearing associated with this work. This project will improve the reliability of the circuit. There were six insulator failures on this circuit that contributed to 14% of the total CMI.

Kentucky Power Company

2007 WORST PERFORMING CIRCUITS

Analysis of Causes/Corrective Actions

Pikeville District

Dewey Station – Inez 34.5kV Circuit (3411401 – SAIFI #1, SAIDI #2)

Approximately 24% of the customer minutes of interruption were due to 2 outages due to failed station equipment. One outage was due to a failed lightning arrestor and the other due to a failed power transformer requiring a mobile installation. Over the past 3 years we have worked to multiphase some long single phase taps at the far end of the circuit in order to better balance loading on the transformer and circuit. By switching more customers to additional phases, fewer customers are outaged when there is a single phase fault. In 2007 we continued cutout replacement on this circuit. We have done a detailed inspection of the station zone. The right of way has been re-cleared in the station zone and inspection aimed at danger trees in the station zone is planned for 2008. The distribution loop around Inez itself is scheduled for reclearing in 2008 along with 70 acres of ground spray. Most significant is the planned distribution automation project scheduled to go in service this spring that will use Lovely-Lovely circuit as an alternate feed when Dewey-Inez is out.

Johns Creek Station – Meta 34.5kV Circuit (3411801 – SAIFI #3, SAIDI #5)

One station outage due to lightning accounts for 32% of the total customer minutes of interruption. Another 10% of the total minutes are due to equipment failure inside the station. Repairs were made in the station during each of these outages. This circuit has been targeted for the past 2 years for cutout replacement. Right of way has been checked and hotspot reclearing has been done in the 3rd zone during 2007. Additional sectionalizing was done in 2007 to install reclosers to create another zone near the end of the circuit reducing exposure by breaking a larger protective zone into 2 equal parts.

Coleman Station – Peter Creek 34.5kV Circuit (3408303 – SAIFI #2)

Trees in and out of right-of-way make up 60% of the outage minutes for this circuit. In 2007 we focused on aerial saw reclearing in inaccessible locations. The station and 2nd zones will be recleared in 2008. Cutout failures added another 19% of outage minutes. This circuit has been targeted for the past 2 years in our cutout replacement program. A current project to serve a new gas compressor customer will split the existing circuit into 2 halves with a new circuit breaker added. A major part of one branch of the circuit will be converted from 12 kV to 34.5 kV and additional sectionalizing will be added resulting in reduced exposure to customers on these circuits. Some load balancing is also scheduled on one tap.

Lovely Station – Wolf Creek 34.5kV Circuit (3202202 – SAIFI #4, SAIDI #8)

A majority of outage minutes are due to trees in or outside of the right of way (62%). The aerial saw was used here in 2007. Five miles of this circuit are scheduled for reclearing in 2008 along with 50 acres of ground spray. Another 14% of outage minutes were due to one incident where a cut control cable on a 3-phase recloser just outside the station kept the recloser from operating properly. The cable was replaced and it is not known if this was the result of vandalism or an accident.

Burdine Station – Levisa 12kV Circuit (3409502 – SAIDI #7)

Trees in or outside of right of way make up 82% of the customer outage minutes for this circuit. Crews have worked in the station zone and the second zone in 2007. The whole circuit is scheduled for reclearing in 2008. We have multiphased and added additional sectionalizing in recent years in an area where we were experiencing increased tree outages. A group of deteriorated poles were changed in the station zone in 2007.

Garrett Station – Garrett 12kV Circuit (3413401 – SAIFI #7)

Right of way reclearing was done in several locations on this circuit in 2007. Trees continued to contribute 42% of the total customer outage minutes on this circuit. It is scheduled for a complete reclear in 2008. Additional switches to allow better sectionalizing during trouble were added during 2007. Equipment failure makes up 35% of the total outage minutes. Failure of a three phase sectionalizer caused 2 outages in one day before it was determined to be faulted. These outages represent 15% of the total minutes. The sectionalizer was removed from service and later replaced. A rotten pole fell causing a loop to burn open on one phase resulting in another 7.4% of the total time.

Topmost Station – Dema 12kV Circuit (3407101 – CAIDI #4)

One outage due to a pole washout during flood conditions made up 66.5% of the customer outage minutes for this circuit.   This is a new circuit created within the past 2 years due to 2 large customer loads requiring station and circuit improvements. The original circuit serving this area was split into two circuits with station reclosers on each, reducing the total exposure to customers in both areas. No additional line work is planned here. Right of way work by ground spraying is planned for 15 acres of this circuit in 2008.

Spring Fork Station – One Phase 12kV Circuit (3404002 – SAIDI #1, CAIDI #3)

Trees out of right of way and lightning were major causes for this circuit in 2007. This area will be patrolled in 2008 to look for danger trees, hotspots, and defective hardware. This circuit has a small number of customers and is very remote. It takes a crew or servicer at least one hour of travel to get to it when there is an outage. If a crew is required to make repairs (as was the case on the tree outages - due to broken poles) then additional outage time occurs as the crew is dispatched and travels to the site.

Hurley Station – Race Fork 12kV Circuit (2970603 – CAIDI #1

Ninety-six Kentucky customers are fed from this Appalachian Power Company station and circuit located in Virginia. Almost 100% of the customer outage minutes were due to a scheduled transmission line outage last year. The Kentucky part of this circuit will be patrolled for danger trees, hotspots, and defective hardware in 2008.

Beefhide Station – Beefhide 34.5kV Circuit (3451201 – CAIDI #8)

One cutout failure contributed over half the outage minutes for this circuit. The time to patrol and find the problem was longer than usual due to the location and terrain involved. This circuit runs along a ridge top and strip mining operation and is not readily accessible. Due to the low number of customers served here the duration for this one outage has skewed the data. One outage cause by a tree out of right-of-way contributed 40% of the outage minutes. Last year there were 32 acres of ground spray done on this circuit. This circuit will be patrolled to check for danger trees and hardware problems in 2008.

Kentucky Power Company

REQUEST

A copy of Kentucky Power Company's Distribution Vegetation Management Plan (VMP) was filed with the Commission on December 21, 2007. Please describe how well KPCo implemented its vegetation management plan, and what changes to the Plan will be implemented in the coming year.

RESPONSE

Since the 2008 Vegetation Management Plan (VMP) was filed with the Commission in December of 2007, the plan is presently being implemented on schedule without modifications. Through February, KPC has spent $1,463,556 in O&M (19.3% of budget) and $392,401 in Capital (14.6% of budget) on the VMP and has completed maintenance on 135 miles of distribution line. Only 5.2% of the total VMP cost has gone to reactive maintenance.

The VMP is intended to be flexible and can be altered to adjust to changing environmental conditions and developing vegetation-related reliability issues as needed throughout the year. Actual adjustments to the 2008 plan over the course of the year will be detailed in the report filed in 2009.

WITNESS: Everett G Phillips