INTER COUNTY
ENERGY COOPERATIVE

A Touchstone Energy Cooperative

March 9, 2009

RECEIVED
MAR 1 0 2009
PUBLIC SERVICE
COMMISSION

Mr. Reggie Chaney
Director of Engineering
Kentucky Public Service Commission
P. O. Box 615
Frankfort, KY 40602-0615

Re: ADMINISTRATIVE CASE NO. 2006-00494 – AN INVESTIGATION OF THE RELIABILITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABILITY MAINTENANCE PRACTICES

Dear Mr. Chaney:

Enclosed is Inter-County Energy Cooperative's Annual Report of Reliability pursuant to the Public Service Commission's Order dated October 26, 2007 for Case No. 2006-00494.

If you have any further questions or comments, please direct those to Marvin Graham, Vice-President of Operations. His direct line is 859-936-7815 or email to marvin@intercountyenergy.net.

Sincerely,

James L. Jacobus
President/CEO

INTER COUNTY

ENERGY COOPERATIVE

A Touchstone Energy Cooperative

Administrative
Case No. 2006-00494

INTER-COUNTY ENERGY
COOPERATIVE CORPORATION
P.O. Box 87 • Danville, KY 40423-0087
Phone: (859) 236-4561 • Fax: (859) 236-3627

INTER-COUNTY ENERGY COOPERATIVE

Administrative Case No. 2006-00494

CONTENT

EXHIBIT1 Electric Distribution Utility Annual Reliability Report

- Contact Information
- Report Year
- Major Event Days
- System Reliability Results
- Outage Cause Categories
- Worst Performing Circuits
- Vegetation Management Plan Review
- Utility Comments

EXHIBIT 2 The Institute of Electrical and Electronic Engineers Standard Number IEEE Std 1366 Guide (Latest Version)

RECEIVED
MAR 1 0 2009
PUBLIC SERVICE
COMMISSION

Electric Distribution Utility Annual Reliability Report

SECTION 1: CONTACT INFORMATION

UTILITY NAME	1.1	Inter-County Energy
REPORT PREPARED BY	1.2	Marvin Graham
E-MAIL ADDRESS OF PREPARER	1.3	Marvin@intercountyenergy.net
PHONE NUMBER OF PREPARER	1.4	859-236-4561 ext. 7815

SECTION 2: REPORT YEAR

CALENDAR YEAR OF REPORT	2.1	2008

SECTION 3: MAJOR EVENT DAYS

T_{MED}	3.1	12.302475
FIRST DATE USED TO DETERMINE T_{MED}	3.2	Jan. 1, 2003
LAST DATE USED TO DETERMINE T_{MED}	3.3	Dec. 31, 2007
NUMBER OF MED IN REPORT YEAR	3.4	4

NOTE: Per IEEE 1366 T_{MED} should be calculated using the daily SAIDI values for the five prior years.

SECTION 4: SYSTEM RELIABILITY RESULTS

Excluding MED

SAIDI	4.1	96.66
SAIFI	4.2	1.2388
CAIDI	4.3	78.027

Including MED (Optional)

SAIDI	4.4	182.9
SAIFI	4.5	2.0599
CAIDI	4.6	88.83

Notes:

1) All duration indices (SAIDI, CAIDI) are to be reported in units of minutes.
2) Reports are due on the first business day of April of each year
3) Reports cover the calendar year ending in the December before the reports are due.
4) IEEE 1366 (latest version) is used to define SAIDI, SAIFI, CAIDI, and T_{MED}

Electric Distribution Utility Annual Reliability Report

SECTION 5: OUTAGE CAUSE CATEGORIES

Excluding MED

CAUSE CODE DESCRIPTION		SAIDI VALUE	CAUSE CODE DESCRIPTION		SAIFI VALUE
high wind	5.1.1	26.68	lightning	5.2.1	0.322
lightning	5.1.2	24.85	high wind	5.2.2	0.2606
rain, ice and snow, or 1	5.1.3	9.9	equipment failure	5.2.3	0.1182
equipment failure	5.1.4	6.47	rain, ice an rain, ice an	5.2.4	0.0971
trees	5.1.5	6.11	trees	5.2.5	0.0653
deteriated installation	5.1.6	4.16	caused by others	5.2.6	0.0438
animals	5.1.7	2.4	animals	5.2.7	0.0433
caused by others	5.1.8	2.29	deteriated installation	5.2.8	0.0371
cars and trucks	5.1.9	1.59	cars and trucks	5.2.9	0.0095
equipment overload	5.1.10	0.18	equipment overload	5.2.10	0.0023

SECTION 6: WORST PERFORMING CIRCUITS

CIRCUIT IDENTIFIER		SAIDI VALUE	MAJOR OUTAGE CATEGORY
Little South - Peytons Store	6.1.1	321	Cars and Trucks
Preachersville - Gooch	6.1.2	316.2	Lightning
Fairgrounds - Gooch	6.1.3	274.2	Lightning
Dixville - T. Adams	6.1.4	210.6	Caused by Others
Jacktown - PeytonsStore	6.1.5	186	High Wind
Battlefield - Perryville	6.1.6	185.4	Lightning
Lancaster - Gooch	6.1.7	177	High Wind
Calvery - Marion Industrial	6.1.8	171.6	Trees
Harrodsburg - Perryville	6.1.9	153	High Wind
Crab Orchard - Gooch	6.1.10	130.8	Deteriorated Installation

CIRCUIT IDENTIFIER		SAIFI VALUE	MAJOR OUTAGE CATEGORY
Preachersville - Gooch	6.2.1	3.6021	Lightning
Fairgrounds - Gooch	6.2.2	3.5131	Lightning
Calvery - Marion Industrial	6.2.3	3.3698	Trees
Lancaster - Gooch	6.2.4	3.3425	High Wind
Little South - Peytons Store	6.2.5	2.5688	Cars and Trucks
Gilberts Ck. - Lancaster	6.2.6	2.1072	Lightning
Raywick - Sulphur	6.2.7	2.0545	High Wind
New Hope - Sulphur	6.2.8	1.8452	equipment failure
Battlefield - Perryville	6.2.9	1.7937	Lightning
Crab Orchard - Gooch	6.2.10	1.7462	Deteriorated Installation

Electric Distribution Utility Annual Reliability Report

Additional pages may be attached as necessary

SECTION 7: VEGETATION MANAGEMENT PLAN REVIEW

Inter-County Energy completed 20 percent of its 5 year vegetation management plan. Inter-County Energy is on schedule to complete its 5 year vegetation management plan within the 5 year plan period.

SECTION 8: UTILITY COMMENTS

Data supplied for the Inter-County Energy system to the PSC in 2008 for the years 2007 and before ranked circuits by multipling SAIDI times CAIDI. PSC did not supply guidence on how it wanted outages reported until after the outage data was sent at the beginning of 2008. I believe the multiplication SAIDI times CAIDI is a better way to rank circuits because it takes both the outage and the recovery time into consideration. It also gives one list of ten worst preforming circuits. Section 4 and section 5 excludes MED and Power Supply.

IEEE Standards

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

1366™

IEEE Guide for Electric Power Distribution Reliability Indices

IEEE Power Engineering Society

Sponsored by the
Transmission and Distribution Committee

Published by
The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

14 May 2004

Print: SH95193
PDF: SS95193

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

The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

Print: ISBN 0-7381-3889-4 SH95193
PDF: ISBN 0-7381-3890-8 SS95193

Introduction

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

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

Patents

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

Notice to users

Errata

Errata, if any, for this and all other standards can be accessed at the following URL: http://standards.ieee.org/reading/ieee/updates/errata/index.html. Users are encouraged to check this URL for errata periodically.

Interpretations

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

The following members of the balloting committee voted on this standard. Balloters may have voted for approval, disapproval, or abstention.

William Ackerman
Paul Anderson
Gregory Ardrey
Ignacio Ares
Kraig Bader
John Banting
Lina Bertling
Edward Bertolini
David Blew
Math H. J. Bollen
James Bouford
Joseph F. Buch
James J. Burke
William Burley
James Cheney
Ali Asraf Chowdhury
Michael Clodfelder
Larry Conrad
Tommy Cooper
John Dagenhart
Ronald Daubert
Frank Denbrock
Andrew Dettloff
John Doering
Gary Donner
Randall Dotson
Robert C. Doyle
Stephen Early
Amir El-Sheikh
Alexander Emanuel
Gary Engmann
Marcel Fortin
Fredric Friend
Keith Frost
Manuel M. Gonzalez
Thomas Grebe
Charles W. Grose
Randall Groves
Erik Guillot
Donald Hall
Kenneth Hall
Dennis Hansen
David Haynes
Charles R. Heising
Richard Hensel
James Hettrick
Philip Hopkinson
Edward Horgan, Jr.
David Jackson
George Kalacherry
George Karady
Mark J. Kempker
Gael R. Kennedy
Mort Khodaie
David Krause
Frank Lambert
Lawrence Larson
Roger Lawrence
Jim Lemke
Gene Lindholm
Gregory Luri
Faramarz Maghsoodlou
John McDaniel
Mark McGranaghan
Gary Michel
Abdul Mousa
Frank Muench
George Niles
Gregory L. Olson
Robert Oswald
Paulette Payne
Daniel Pearson
Carlos Peixoto
Michael Pehosh
Charles Perry
Paul Pillitteri
Orville Plum
Percy Pool
John Redmon
Joseph Renowden
Rodney Robinson
James Ruggieri
Daniel Sabin
Bob Saint
Surya Santoso
David Schepers
Neil Schmidt
Ken Sedziol
Tom Short
Chris Siebenshuh
H. Jin Sim
Cameron Smallwood
James Smith
Devendra K. Soni
Keith Stump
Malcolm Thaden
Elisabeth Tobin
Hahn Tram
Mani Venkata
Joseph Viglietta
Carl Wall
Daniel Ward
Cheryl A. Warren
Lee Welch
Val G. Werner
Charles Williams
James Wilson

CONTENTS

3. Definitions

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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).

To calculate the index, use Equation (8).

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

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).

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

To calculate the index, use Equation (10)

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

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).

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

To calculate the index, use Equation (12).

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

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).

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

To calculate the index, use Equation (14).

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

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

4.4.2 Momentary average interruption event frequency index ($MAIFI_E$)

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

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

To calculate the index, use Equation (22).

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

4.4.3 Customers experiencing multiple sustained interruption and momentary interruption events ($CEMSMI_n$)

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

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

To calculate the index, use Equation (24).

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

4.5 Major event day classification

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

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

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

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

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).

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

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

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

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

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

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

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.

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

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

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

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

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

5.3 Examples

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

5.3.1 Momentary interruption example

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

Figure 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.

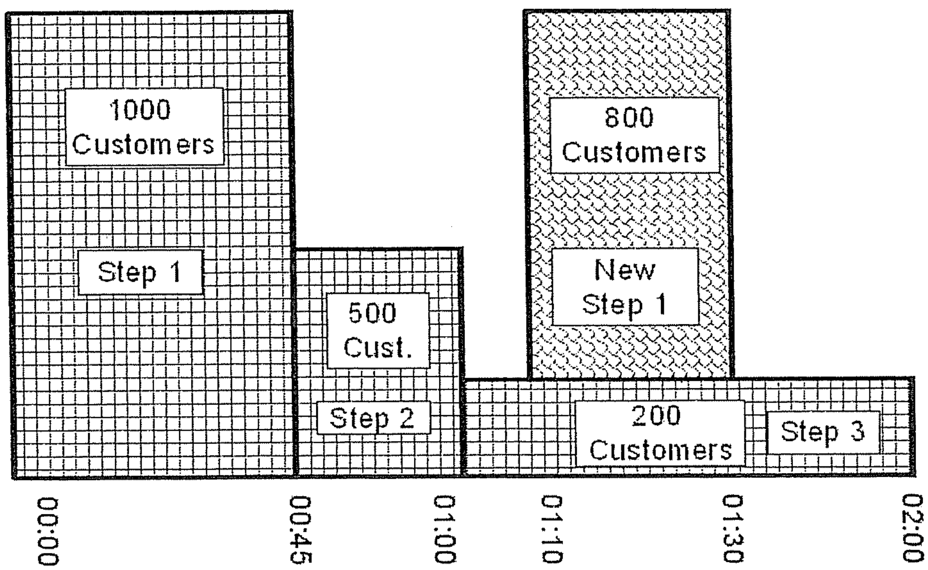

Figure 2—Step restoration time chart

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	01:10–01:30	800	16 000
Total customer for SAIFI count (Only step 1's)		1800	
Total CMI			80 500

Annex A

(informative)

Survey of reliability index usage

The Working Group on System Design conducted three surveys on distribution reliability index usage. The first one was completed in 1990 and the second was completed in 1995 and the third one was completed in 1997. The purpose of the surveys was to determine index usage and relative index values. In 1990, 100 United States utilities were surveyed, 49 of which responded. In 1995, 209 utilities were surveyed, 64 of which responded. In 1997, 159 utilities were surveyed and 61 responded. Responding utility locations are shown by state in Figure A.1. Newer surveys are being performed by Edison Electric Institute (EEI). The data provided is not comparable because utilities provided whatever information was easily obtainable.

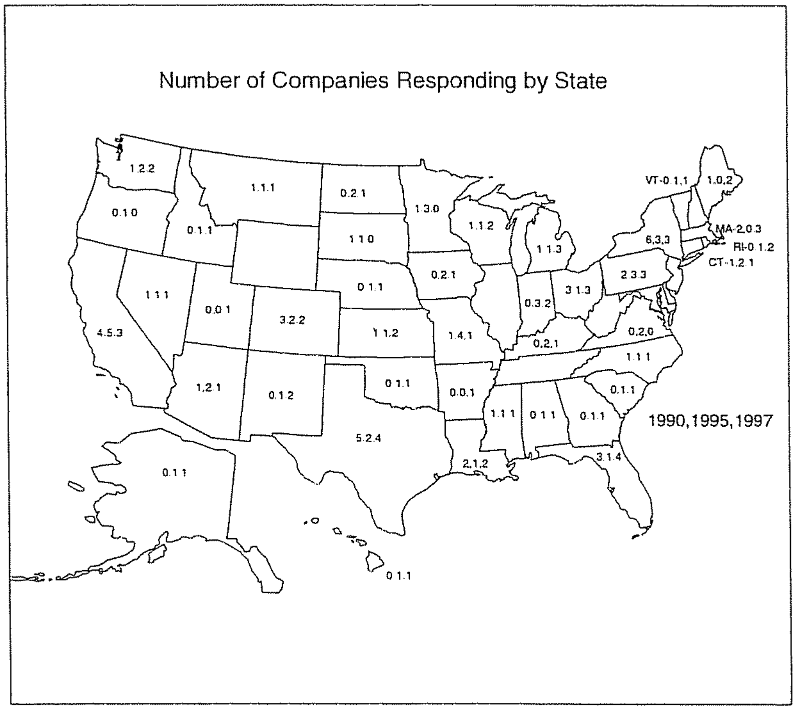

Figure A.1—Location of companies that respond to surveys

All surveys showed that the most commonly used indices are SAIFI, SAIDI, CAIDI, and ASAI. Figure A.2 shows the percentage of companies using specific indices in 1990. Figure A.3 shows the same information for 1995 and 1997. Figures A.4–A.8 show data on the most commonly used indices given by quartiles where Q1 is the top quartile. The data shown in the Q1 column means that 25% of utilities have an index less than the value shown. For further clarification:

Q1: 25% of utilities have an index less than the value shown

Q2: 50% of utilities have an index less than the value shown (the median value)

Q3: 75% of utilities have an index less the value shown

Q4:100% of utilities have an index less the value shown

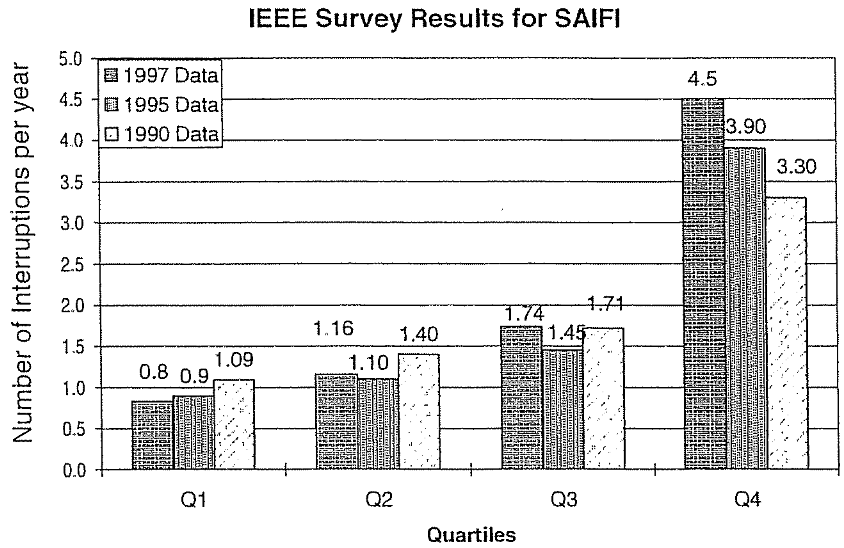

Figure A.4—SAIFI– 1990, 1995 and 1997 survey results [B1] and [B11]

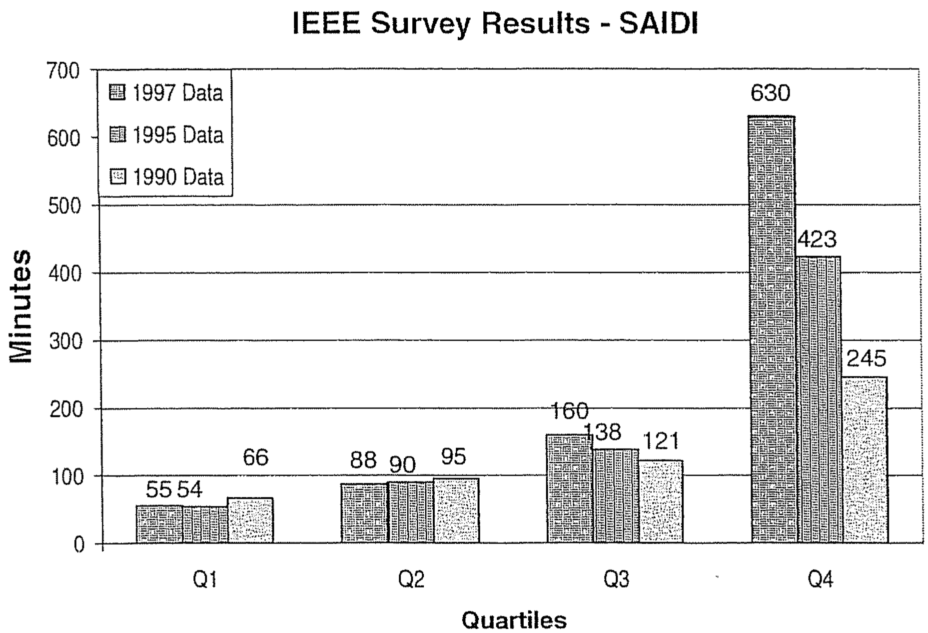

Figure A.5—SAIDI– 1990, 1995, and 1997 survey results [B1] and [B11]

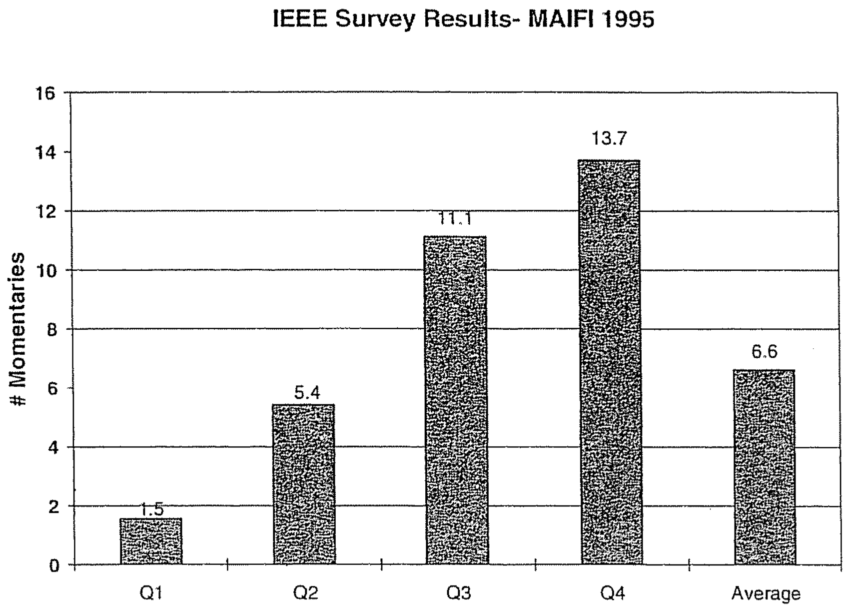

Figure A.8—MAIFIQ-- 1995 survey results (1990/7 data not available) [B1]

A.1 Cause codes

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

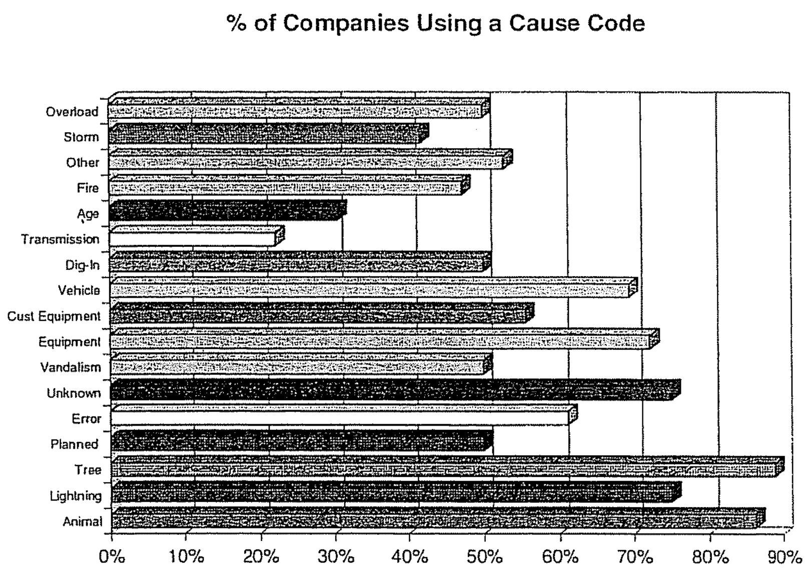

Figure A.9—1997 Cause code usage 1

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.

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

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).

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

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

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.

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

and

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

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

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 2.5β 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.

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.