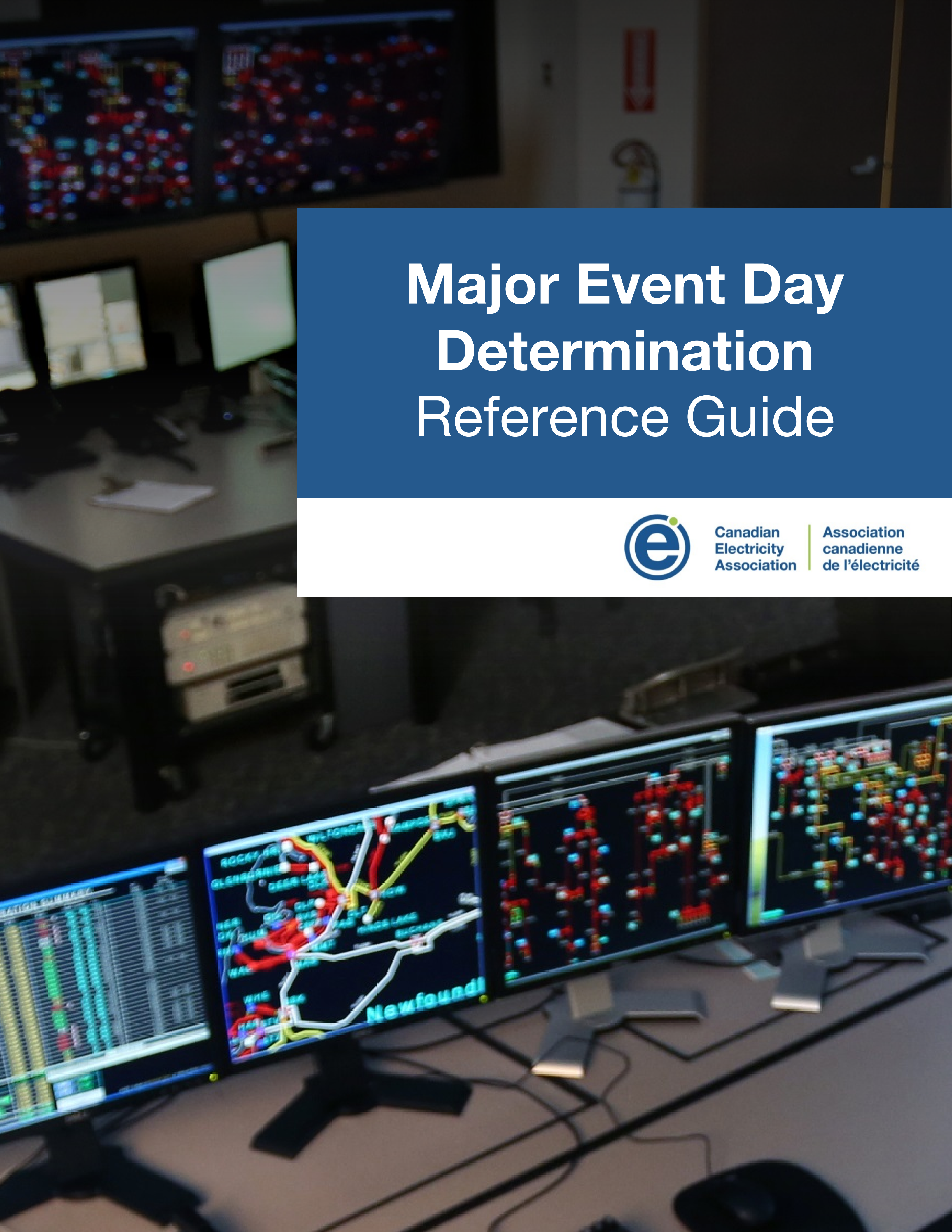

Major Event Day Determination
Reference Guide

Canadian Electricity Association | Association canadienne de l'électricité

Acknowledgements

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About the Canadian Electricity Association (CEA)

A safe, secure, reliable, sustainable and competitively priced supply of electricity is essential to Canada's prosperity.

CEA members generate, transmit and distribute electrical energy to industrial, commercial, residential and institutional customers across Canada every day. Members include integrated electric utilities, independent power producers, transmission and distribution companies, power marketers and the manufacturers and suppliers of materials, technology and services that keep the industry running smoothly.

About the Service Continuity Committee (SCC)

The Service Continuity Committee is recognized as a trusted forum in distribution reliability practices through shared experiences and data analysis. The Committee provides a mechanism to collect, analyze and report system distribution outages data, processes and functions in order to encourage members to gain and share insights and benefits through a community of practice.

The Service Continuity Committee collects, analyzes and reports on a comprehensive set of system reliability and performance data. CEA's Service Continuity Reporting System was inaugurated on January 1, 1986. The databases have evolved over time to the current web-based system. The system is based on definitions that have now been accepted as industry standards.

In 2003, SCC began collecting data on Major Event Days (also referred to as Most Prominent Events (MPE) in SCC). SCC also identifies 'significant events' (or catastrophic events); these are MEDs that are deemed so large that they impact the Canadian Index values.

Recommended citation: "Major Event Day Determination Reference Guide," Canadian Electricity Association, 2015.

Cover photo courtesy of Newfoundland Power Inc.

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Contents

Preamble

A discussion on the use of the IEEE 2.5 Beta (β) method took place at the May 2014 Service Continuity Committee (SCC) workshop in Fredericton, New Brunswick.

Workshop attendees reviewed a proposed modification to the IEEE 2.5β method that would compensate for the fact that data becomes distorted when a 24-hour period is used. The presentation highlighted using a longer period than 24 hours to calculate individual SAIDI values. The proposed period was a two-day rolling methodology.

Based on interest from those attending the workshop, a task force was formed to review the IEEE 2.5β method and identify which method should be incorporated into utility reporting.

Using data from a number of utilities, it was determined that the two-day rolling method did not fit well for all utilities.

Over a period of several months, a total of three methods were examined to determine their effectiveness with utility data. An additional methodology is identified and included in Appendix A.

Reviewed Methods

- IEEE 2.5β
- Two Consecutive Rolling Calendar Days
- Fixed Percentage Based System Average Interruption Duration Index (SAIFI) Threshold

Supplemental Methodology

- Box-Cox Transformation (See Appendix A)

Background

System reliability analyses are a vital part of system planning and of customer service performance metrics for electric utilities. These analyses shed light on system performance trends and identify key areas for utility improvement, including:

- Investing more in aging infrastructure;
- Increasing vegetation management;
- Mitigating climate change scenarios; and,
- Researching new equipment technologies or standards.

To ensure these analyses accurately reflect the typical performance of a utility, extenuating circumstances which can significantly skew the results must be removed. This is typically done by identifying Major Event Days (MED).

"Major Events" are defined by the "IEEE Guide for Electric Power Distribution Reliability Indices" (1366-2012) as:

"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".

The IEEE standard (1366-2012) further defines a Major Event Day (MED) as:

"A day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold value. 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 during severe weather). Activities that occur on Major Event Days should be separately analyzed and reported."

There have been several articles which highlight the fact that when the SAIDI distribution is not normally distributed, the resulting number of Major Event Days is unusable data for utilities.[1]

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[1] N. Hann and C. Daly, "Investigation of the 2.5 Beta Methodology", IEEE, 2011.
R. Billinton and J. Acharya, "Major Event Day Segmentation", IEEE Trans. Power Systems, Vol 21, no 3. Pp. 1463-1464, Aug. 2006.
R. D. Christie, "Statistical Classification of Major Event Days in Distribution Systems Reliability", IEEE Trans. Power Del., vol. 18, no.4, pp.1336-1341, Oct. 2003

A spring storm in southern Alberta causes significant damage to a FortisAlberta Inc. power line. *Photo courtesy of FortisAlberta Inc.*

In addition, the IEEE standard (1366-2012) uses a 24-hour window in which to calculate SAIDI. The following is an excerpt from the IEEE standard 1366-2012 guide, identifying the known inaccuracy of this methodology:

"When a major event occurs that lasts through midnight (for example, a six hour hurricane which starts at 9:00 p.m.), the reliability impact of the event may be split between two days, neither of which would exceed the T_{MED} and therefore not be classified as a MED. This is a known inaccuracy in the method, which 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 MED identification threshold was set by trading off between the desire to reduce statistical variation in the threshold (for which more data is better) and the desire to see the effects of changes in reliability practices in the reported results, and to limit the amount of data which must be archived."[2]

This document will attempt to explore various alternate methods of reporting Major Event Days (MED) and determine the feasibility of using a consistent method of MED calculations.

[2] IEEE Std 1366-2012, "IEEE Guide for Electric Power Distribution Reliability Indices", IEEE, May 2012

IEEE 2.5β Method

The IEEE standard 1366-2012 uses the '2.5β method' to determine the number of Major Event Days. The rationale for this method is as follows:

- For some variable, X, which has a mean, a, and a standard deviation, b, a threshold T is defined which is 2.5 standard deviations above the mean of the distribution, so T = a + 2.5 b.
- We can do this for any variable with any distribution (provided a and b exist).
- The IEEE Working Group used a Gaussian (or normal) distribution to do their calculations. They chose the 2.5 multiplier so that the probability of exceeding T was 0.000621, or 2.3 days/year. This choice was based on consensus reached among the Distribution Design Working Group members on the appropriate number of days that should be classified as Major Event Days.

Pros	Cons
• Given a large enough data set, the data set is more likely to follow a normal distribution. • SAIDI-based calculation considers both the number of customers interrupted, as well as the duration of interruption, and thus the full extent of the impact. • This method is used by many utilities in North America.	• For smaller utilities with fewer interruption events, the data will not conform to a normal distribution. • Even in the best cases, the data will likely not pass the p-test for normality. This is mostly due to days with low or high SAIDI that skew the results of the p-test. • Events that run over the end of day create inaccuracies in the overall identification of MEDs, since such events could be missed. • Other characteristics may impact potential **log-normal distribution** such as geographic size and/or percentage of underground network.

If the data is not log-normal, the IEEE 2.5β method is not advisable. The definition of log-normal can be described in the following manner:

"A log-normal distribution is a continuous probability distribution of a random variable whose logarithm is normally distributed."[3]


Photo courtesy of Saint John Energy.

Example data

Below are two charts visualizing two datasets (2010-2014). The first graph (Figure 1.0) illustrates the raw data distribution and the second (Figure 2.0) illustrates the IEEE 2.5β method daily SAIDI.

The data in the figures was calculated using 321,285 outages.

Mean = -1.31

Standard deviation = 1.08

Threshold = $\left(e^{(\text{mean}+2{,}5*(\text{Standard deviation}))}\right) = 4.04$

Number of days in 2014 > 4.04 = 8, down from 15 in 2013, which was a very active year.

[3] Log-Normal Distribution, Wikipedia, 2015. Available from http://en.wikipedia.org/wiki/Log-normal_distribution

Figure 1.0: Raw Data Distribution (2010-1014)

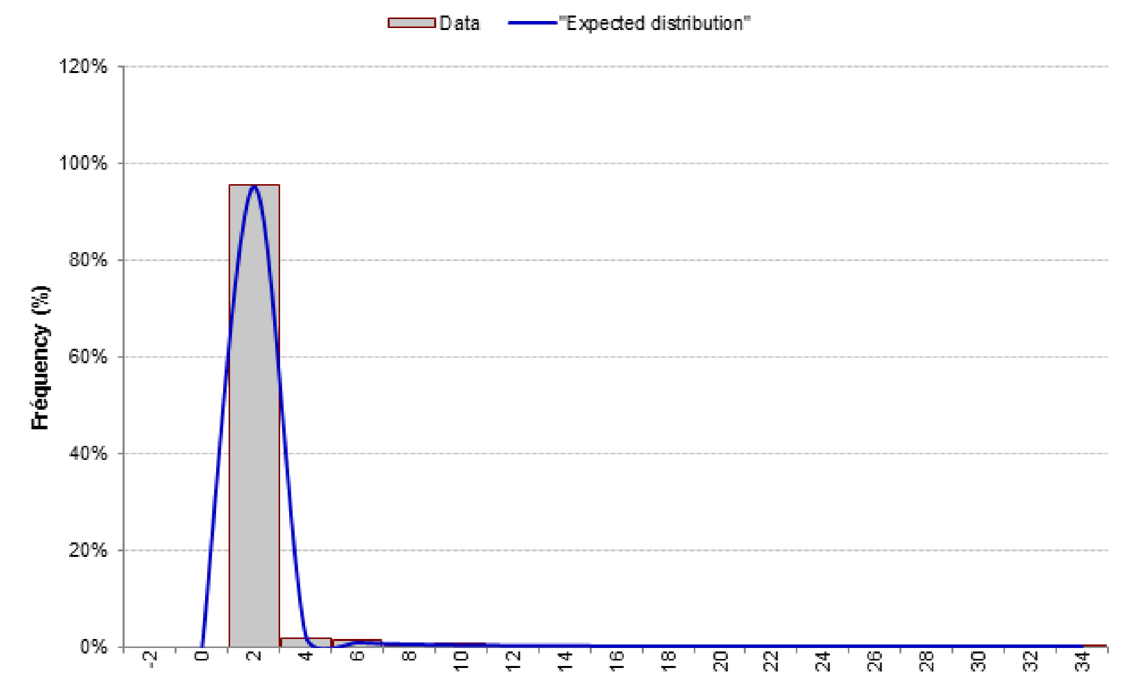
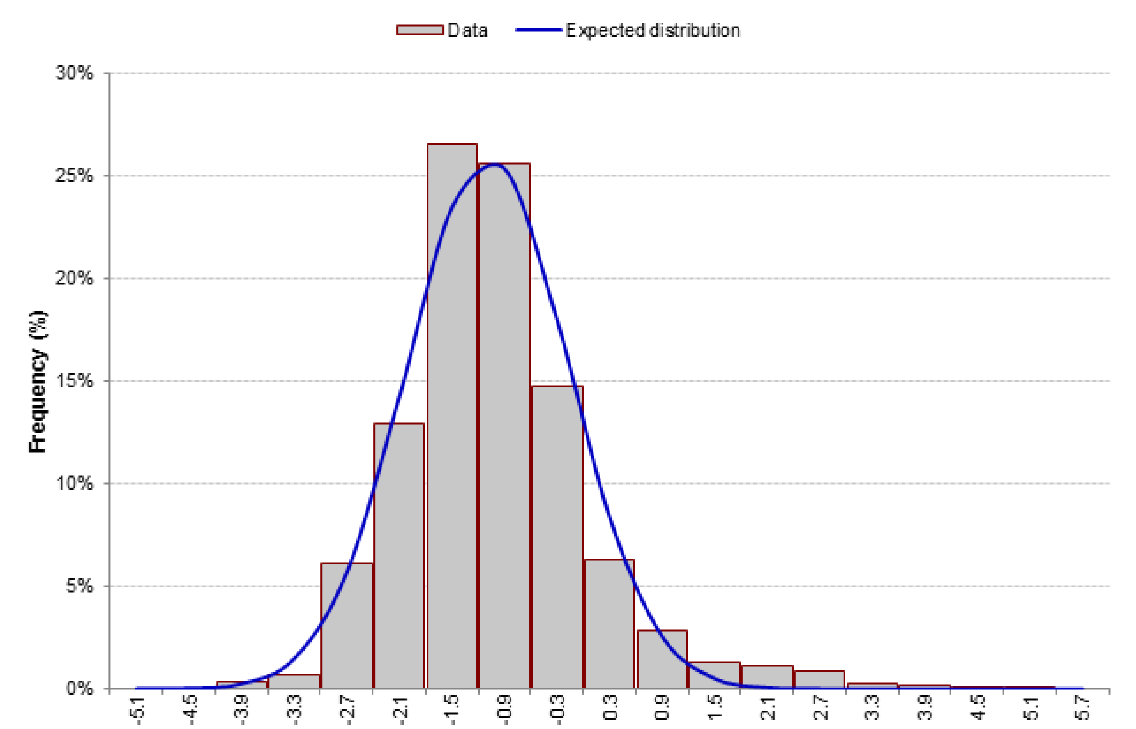


Figure 2.0: IEEE Distribution for Daily SAIDI (2010-2014)



Other considerations

That same utility used the IEEE 2.5β method on a subset of the utility; they selected an urban centre.

Below are the daily SAIDI results for the Urban Centre.

Based on 35 741 outages from 2010 to 2014.

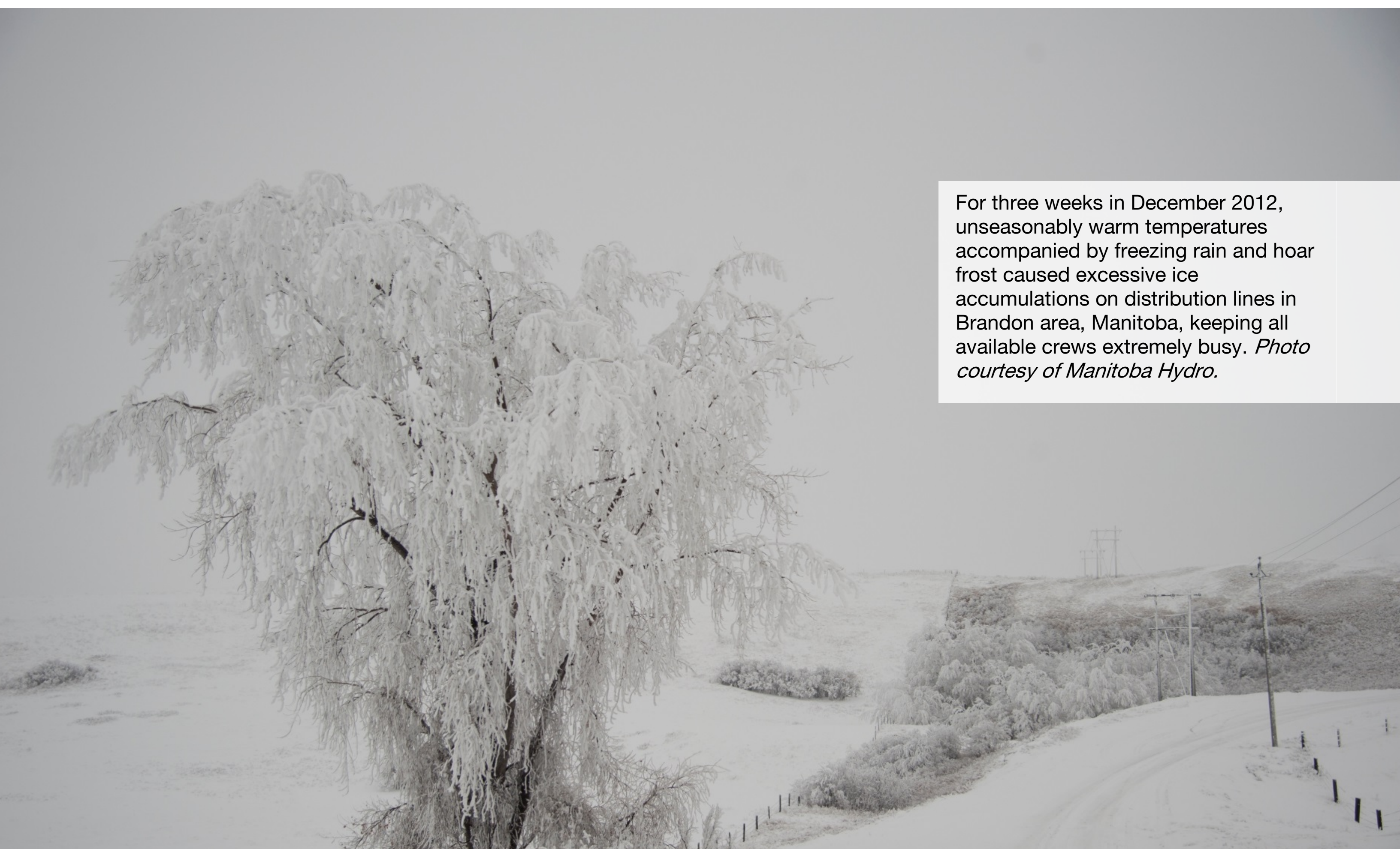
Mean = -2.86

Standard deviation = 1.31

Threshold = $(e^{(\text{mean}+2.5*(\text{Standard deviation}))})$ =1,51

2 days > 1,51 in 2014 against 8 when it includes the whole province.

As we can see, geography (i.e. size and climate) proves to be a factor. Other factors also significantly impact the IEEE usage, as we can see in Figures 3.0 and 4.0. Over 40% of this urban centre's distribution system is underground compared to ≈4% for the rest of the province.



For three weeks in December 2012, unseasonably warm temperatures accompanied by freezing rain and hoar frost caused excessive ice accumulations on distribution lines in Brandon area, Manitoba, keeping all available crews extremely busy. *Photo courtesy of Manitoba Hydro.*

Figure 3.0: Raw Data Distribution of Urban Centre

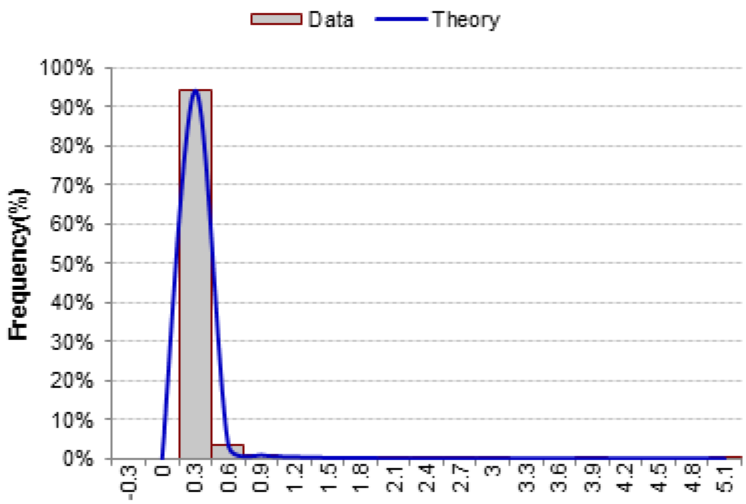
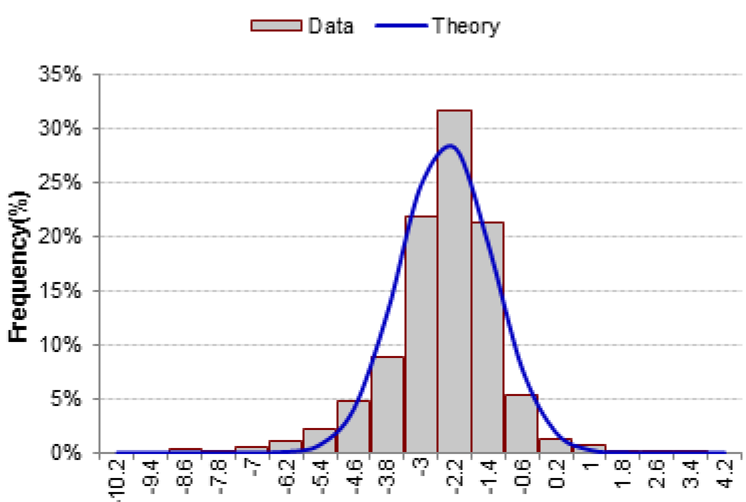


Figure 4.0: Daily SAIDI Distribution of Urban Centre



Noted failings of IEEE 2.5β

Australian Experience

The Australian Energy Regulator (AER) has implemented Performance Based Ratemaking in Australia using the IEEE standard for identification of Major Event Days. Utilities have discovered their event data does not fall into a log-normal distribution. They recommend that the IEEE 2.5β not be used for Performance Based Ratemaking and/or used in calculation of Major Event Days.[4]

IEEE Working Committee Statement

Even IEEE has commented on the failings of IEEE 2.5β:

"It is recommended that the identification and processing of catastrophic events for reliability purposes should be determined on an individual company basis by regulators and utilities, since no objective method has been devised that can be applied universally to achieve acceptable results."[5]

Recommendation

The validity of the IEEE 2.5β method, as described by the standard, depends on a normal distribution of log (SAIDI). IEEE 1366-2012 assumed that SAIDI has a log-normal distribution and hence log (SAIDI) would have a normal distribution, and the probability calculations would apply to it.

The use of a mathematical probability distribution such as the normal or log-normal distribution to describe the actual distribution of some variable is valid as long as the distribution matches the dataset. Therefore, the working group advises that use of the IEEE methodology be restricted to utilities that have a normal distribution of their datasets.

If a dataset does not fall into the log-normal distribution that is required for IEEE 2.5β, then it is advisable to seek another solution for allowable MEDs.

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[4] SA Power Networks, 2014, "Proposed Amendment to STPIS Guideline". Available from http://www.aer.gov.au/sites/default/files/SAPN%20-%2023.14%20PUBLIC%20-%20SAPN%20Proposed%20amendment%20to%20STPIS%20Guideline.pdf

[5] IEEE Std 1366-2012, "IEEE Guide for Electric Power Distribution Reliability Indices", IEEE, May 2012

Two Consecutive Rolling Calendar Days

Many Canadian weather events span multiple days; hence, a variation in methodology is required.

A variation to the IEEE methodology is proposed by spreading the events over two or more days. This is achieved by using a period longer than 24 hours to calculate individual SAIDI. If the number of customers remains the same, the SAIDI for a two-day period is the sum of the two days' SAIDI values.

The "two days" method is calculated using a rolling two days, (i.e. Jan01 and Jan02, Jan02 and Jan03, Jan03 and Jan04 etc.).

Pros	Cons
• By taking the average, the data in general becomes more normal as large variations are normalized. • This method normalizes SAIDI data to a meaningful degree and addresses events which are spread over two days.	• The averaging of two days of SAIDI is statistically arbitrary. We are no longer looking at identifying Major Event Days, but rather Major Event Averaged Days. In this case, how do we go about determining which events are considered part of a Major Event Day if the result was derived from an average? • The data distribution becomes smoother as the average number of days for the calculation increases. • This method is not an international standard by a recognized body.

A sample utility dataset for five years of SAIDI will explain how the adoption will result in improving the IEEE methodology. Figures 5.0 and 6.0 show the daily SAIDI for a period of five years and the resulting distribution.

The mean of the daily SAIDI data is -3.30 while the median is -3.20. The skew is -0.37 with a 95% confidence interval. This data is not log-normal, so applying IEEE 1366 methodology would create inconsistencies. In fact, by using this methodology, the utility in the example did not have any MED days for one year, yet it is expected that the utility should have at least 2.3 days as MED based on the definition and methodology.

Figure 5.0: Five Year Utility Data for SAIDI

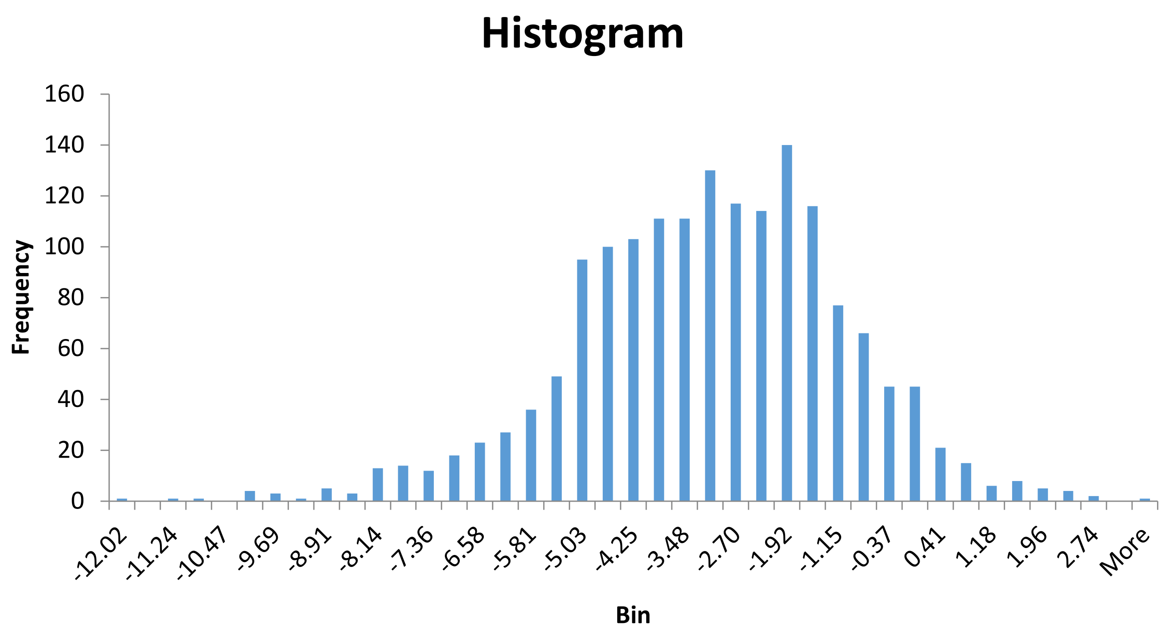
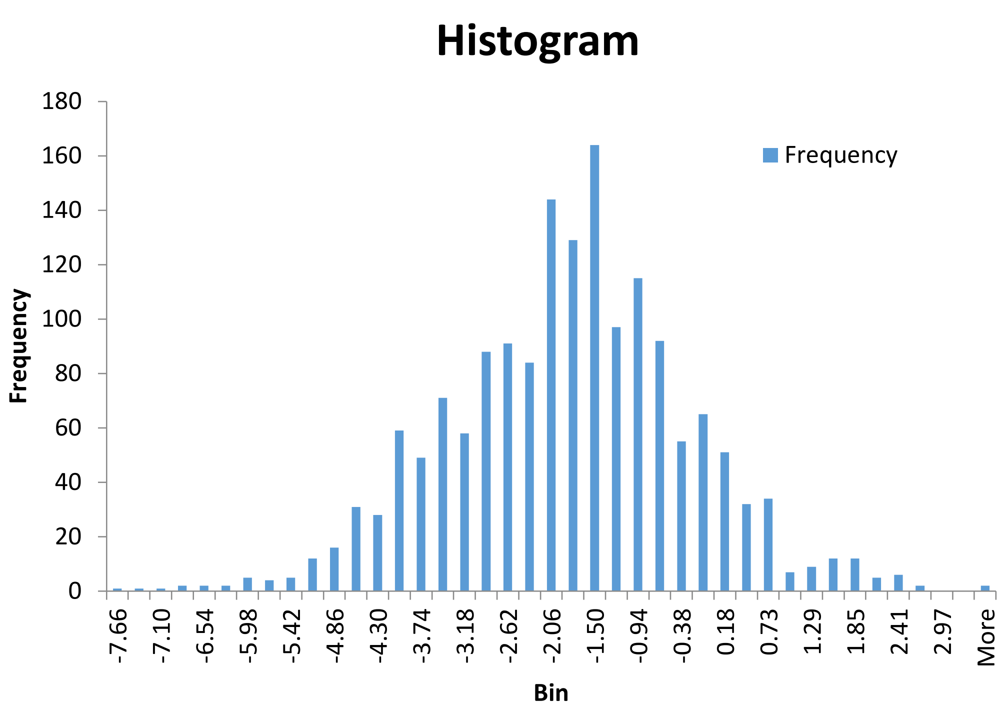


Figure 6.0: Five Year Utility Data for Rolling 2 Day SAIDI



The mean of the rolling two-day SAIDI data is -1.98 while the median is -1.90, and the skewness is reduced to -0.07 with 95% confidence. The distribution approaches normal distribution; however, it is more peaked than normal distribution.

The resulting calculation of MED with the IEEE 2.5β and the modified IEEE 2.5β using rolling SAIDI is shown in Table 1.0.

Table 1.0: Comparison of Calculation of MEDs Using IEEE 2.5β and Modified IEEE 2.5β Two-Day Rolling Period.

Method	Natural log – average(α)	Standard Deviation (β)	T_{MED}	Resulting Major Event Days
IEEE 2.5β	-1.98	1.55	6.23	7
Modified IEEE 2.5β	-3.30	1.94	6.70	11

The modified IEEE 2.5β does normalize SAIDI data to a meaningful degree and addresses events which are spread over two days. This method is very convenient in application; however, there are other transformations which will normalize the data even further.

Recommendation

This method holds true for some utilities looking at calculating the allowable days for Major Event Days; however, not all utilities can use this methodology. During verification of data it was discovered that for utilities with high volumes of outages or large geographies, their data could not be normalized into the two-day rolling model.

However, a number of utilities found the results of the two-day rolling methodology increased the allowable MEDs to a realistic extent (by varying degrees) compared to the IEEE 2.5β Method. Those utilities may consider evaluating and implementing this methodology.

Fixed Percentage Based SAIFI Threshold

Several utilities look at fixed percentage amounts that indicate a Major Event Day. The percentage is generally small. For the purposes of this document, 10% has been used, and this number can vary by utility. These events are classified under three categories:

- *Force Majeure* (Most Prominent Event)
- Storm Days
- Non-Storm Events (Blue Sky Days)

Fixed Percentage Classifications

Force Majeure Days (Most Prominent Event)

Distribution utilities deem a *Force Majeure* to have occurred when 10% or more of total distribution customers have been interrupted by an event. The cause of a *Force Majeure* may be a storm (the most common cause), a blackout, or any other event that interrupts 10% or more customers and causes a change in the normal restoration business process.

All distribution customers interrupted throughout the duration of the *Force Majeure* event—while normal restoration business processes are suspended—are counted in the determination of the numerator of the percent of customers interrupted. The denominator is the total number of customers served at the end of the month when the *Force Majeure* occurred.

For the Canadian Electricity Association (CEA), this type of event is also called a Most Prominent Event (MPE). IEEE identifies them as Major Event Days. Extreme *Force Majeure* Events are further deemed as Significant Events (SE) CEA. IEEE identifies SEs as catastrophic events.

In this methodology, we see storm events and non-storm events as subsets of *Force Majeure* Days.

Storm Events/Days

Distribution utilities deem a storm day to have occurred based on two major conditions:

- Magnitude of the interruptions; and,
- Verification from weather data and reported magnitude of the interruptions.

There are two possible sets of criteria for identifying storm events:

1. The number of interruptions on a day met or exceeded 5% of the monthly average number of interruptions for the past five years.
    a. Calculation: The numerator is the total number of interruption on the day. The denominator is the monthly average number of interruptions for the past five years.
2. A minimum 4% of total distribution customers have been interrupted.
    a. Calculation: All distribution customers interrupted throughout the duration of the storm event—while normal restoration business processes are suspended—are counted in the determination of the numerator of the percent of customers interrupted. The denominator is the total number of customers served at the end of the month when the storm occurred.

Verification from weather data and magnitude reports:

If the Event (Days) meet the above criteria, and the weather data and report (e.g. weather data from Environment Canada, internet sources, control center weather, and field reports) support that a storm occurred prior, on, or after the date, the Event (Days) is deemed as a Storm Event (Days).

Each day is evaluated under both conditions to be confirmed as a storm day.

An event may go over two or more calendar days, when a storm starts before and concludes after midnight.

This information is then confirmed by data available through weather maps from varied sources (i.e., internet), in addition to line crew reports, weather office reports, and news reports.

Non-Storm Events/Days (Blue Sky Days)

Distribution utilities deem a non-storm day as one that is neither a *Force Majeure* nor a storm day. Non-storm days experience no obvious storm events; however, power outages may still take place.

Pros	Cons
• This method will always capture events that impact a large portion of the customers. This will help reduce the impact of high SAIFI, low SAIDI events that other metrics do not consider MED, e.g. a system-wide interruption of five minutes. • This method provides flexibility of MED declaration based on event analysis.	• A SAIFI-based threshold does not consider the length of an outage, and thus ignores the full extent of the impact of minor outages. • This method does not consider the historical impacts of outages to a utility. For example, If a utility has a daily outage affecting X% or more customers per year, those events should not necessarily be excluded from a benchmarking study due to the fact that the event occurs so commonly. There is the question of how to determine the percentage to use as the threshold.

Photo courtesy of FortisAlberta Inc.

Table 2.0: Utility Fixed Percentage Sample Data

Sample Calculation for Fixed Percentage Method										
Last 5 Years' Average Monthly # of Interruptions (Monthly # of Int):				3069	Total Customer Served:	1288283				
Month	Date	# of Int	Customer-Interruptions	$\frac{\#\ of\ Int}{Monthly\ \#\ of\ Int}$	Meet Storm Threshold (5%)	$\frac{Customer - Interruptions}{Total\ Customer\ Served}$	Meet Storm Threshold (4%)	FM Check (10%)	Weather Report confirmed	MED
11	1	51	6384	1.7%	N	0.5%	N			Non-Storm
11	2	46	18934	1.5%	N	1.5%	N			Non-Storm
11	3	55	14182	1.8%	N	1.1%	N			Non-Storm
11	4	77	9630	2.5%	N	0.7%	N			Non-Storm
11	5	96	4058	3.1%	N	0.3%	N			Non-Storm
11	6	49	898	1.6%	N	0.1%	N			Non-Storm
11	7	56	2577	1.8%	N	0.2%	N			Non-Storm
11	8	46	1504	1.5%	N	0.1%	N			Non-Storm
11	9	54	8823	1.8%	N	0.7%	N			Non-Storm
11	10	80	1847	2.6%	N	0.1%	N			Non-Storm
11	11	46	1389	1.5%	N	0.1%	N			Non-Storm
11	12	107	15572	3.5%	N	1.2%	N			Non-Storm
11	13	50	5850	1.6%	N	0.5%	N			Non-Storm
11	14	63	11458	2.1%	N	0.9%	N			Non-Storm
11	15	49	3056	1.6%	N	0.2%	N			Non-Storm
11	16	47	26886	1.5%	N	2.1%	N			Non-Storm
11	17	74	17247	2.4%	N	1.3%	N			Non-Storm
11	18	185	66109	6.0%	Y	5.1%	Y		Y	Storm
11	19	76	5613	2.5%	N	0.4%	N			Non-Storm
11	20	99	13224	3.2%	N	1.0%	N			Non-Storm
11	21	54	6428	1.8%	N	0.5%	N			Non-Storm
11	22	49	5077	1.6%	N	0.4%	N			Non-Storm
11	23	44	12111	1.4%	N	0.9%	N			Non-Storm
11	24	1094	210701	35.6%	Y	16.4%	Y	18.5%	Y	FM
11	25	665	27000	21.7%	Y	2.1%	N		Y	FM
11	26	138	5518	4.5%	N	0.4%	N			Non-Storm
11	27	70	4351	2.3%	N	0.3%	N			Non-Storm
11	28	54	6074	1.8%	N	0.5%	N			Non-Storm
11	29	66	8139	2.2%	N	0.6%	N			Non-Storm
11	30	51	4888	1.7%	N	0.4%	N			Non-Storm

Recommendation

This methodology provides a unique look at the data, and the utility can adjust the fixed percentage internally. The fixed percentage may vary amongst utilities that use this methodology. This is based on a few factors including utility size and weather patterns that affect the utility. Some utilities are more prone to storm effects than other utilities based on geographic location, grid configuration, and more. Fixed percentage is a viable option for utilities with data that does not fit into either the IEEE methodology or the two-day rolling average methodology.

A Newfoundland Power vehicle assesses damage on Ruby Line during Tropical Storm Leslie. Photo: The Telegram. *Photo courtesy of Newfoundland Power Inc.*

Conclusion and Recommendations

The point of determining MED is to identify those events that are outside the control of the utility. Removing those numbers provides the utility with a level of performance that is more acceptable than when incorporating MED data.

Changing weather patterns, aging infrastructure, various climates and geographies, as well as utility customer, employee, and grid size all play a role in the utilities' datasets, from restoration times to frequency outages. It can be argued that regulator activities play a role in outages as well. Regulatory decisions that withhold rate increases may force utilities to maintain continually aging equipment that will eventually fail.

There is a growing desire amongst government bodies, including regulatory agencies, to blanket the industry in a one-size-fits-all model for topics from customer service to reliability and expenses. Such blanket models are not considered to be in the best interest of the utility nor the utility rate-payers.

In the context of identifying major event days with a standard formula, it is recommended that all utilities not use the same formula. Each utility must analyze its datasets first, and then determine the best method. A utility that spans over 60,000 square kilometers will not have the same dataset as one that spans 400 square kilometers or one that spans 800,000 square kilometers.

Where the IEEE 2.5β method works for a number of utilities, it may not work for other utilities. The same bodes true for the other methods identified in this reference guide.

In conclusion, utilities must be flexible in their operations in order to meet growing markets and demand. In addition to changing loads, changing weather, and changing technology, they must contend with aging infrastructure and the aging workforce. Furthermore, they must be ready for challenges within their local political and economic environments. As part of this operational flexibility, utilities must be able to use their best judgement to choose their own method for identifying Major Event Days.

Exploring the various MED methodologies raises another avenue of thought. We must ask the following question:

"What's the practical purpose to pre-determine the amount of Major Event Days?"

Regardless of the applied model, is it not possible for a utility to exceed the allowable amount of MED days in a given year simply because Mother Nature is working overtime. Surely Hurricane Sandy, Hurricane Arthur, and the 2013 Ice Storm have taught us that.

The following flowchart identifies potential solutions if utilities must identify allowable major event days for a year.

1 IEEE 2.5 β → 2 2-Day Rolling Average → 3 Fixed Percentage

Initially, utilities may wish to use the IEEE methodology. If the data is not log-normal then go to step 2 and apply the 2-Day Rolling Average methodology. If the data does not fall into either solution, then move to the third solution of using a Fixed Percentage.

If none of those are acceptable, then an examination of other solutions may be advisable. Several European nations say that utilities identify their Major Event days on a case-by-case basis (See Appendix B).

As discovered from trials in Australia, there should never be penalties if a utility exceeds the allowable amount of MEDs based on a given formula. A number of Australian utilities have gone back to their regulator and identified that their data is not log-normal and should not be penalized because their regulator requires them to use the IEEE 2.5β methodology.

Regardless of the selected solution for MED identification, the task group has determined that the utility must remain historically accurate and must be consistent from year to year. If a utility must change methodology, they must have justification to change. If one method is adopted, the task group also advises that performing calculations on a second methodology is advisable in order to highlight any differences between the methods and the results.

Photo courtesy of Columbia Power Corporation.

Appendix A: Box-Cox Transformation

The Box-Cox transformation is recognized as an alternative method. However, no dataset has undergone sampling for the purposes of this document because of the complexity of the formula.

Data transformation, and particularly the Box-Cox power transformation, is a remedial action that may help to make data normal. By understanding the concept of transformation and the Box-Cox method, the user will be able to apply the methodology.

Transforming data means performing the same mathematical operation on each instance of original data. Some transformations are called linear transformations because a mathematical function is used, such as multiplying or dividing by a coefficient. The linear transformations do not change the shape of the data distribution and do not change the underlying distribution.

The Box-Cox transformation is a particularly useful family of transformations, and it is used to normalize the data.

The variable X is defined as:

X(λ) = (Xλ – 1) / λ for λ ≠ 1, and X(λ) = log(X) for λ = 0.

The Box-Cox normality plot is a plot of these correlation coefficients for various values of the λ parameter. The value of λ corresponding to the maximum correlation for each iteration is an optimum choice for λ.

In this particular instance, the SAIDI data is used to estimate λ. The transformed SAIDI is represented as:

SAIDI(λ) = (SAIDI λ – 1) / λ

Calculation of λ and SAIDI(λ) are completed using standard programs.

Using this transformation, α and β (the mean and standard) of the transformed data is obtained as follows:

α= mean(SAIDI(λ)) and β = sd(SAIDI(λ)),
TMED = α + 2.5 β

Then any day where SAIDI(λ) > T_{MED} is defined as a Major Event Day.

The SAIDI threshold value equivalent to T_{MED} is found by inverting the transformation, thus:

SAIDI(MED) = (λ SAIDI(λ) + 1)1/ λ

The iteration is then carried out to find a stable value of T_{MED}. This involves recalculating λ and SAIDI(λ) at each stage.

Appendix B: International Sample

Jurisdiction	Major Event Day Methodology[6]
Australia	Varies by province: IEEE 2.5β; natural major event SAIFI based, on a once in a 5 year occurrence;
China	None, one is forthcoming in 2016-2017
Denmark	Exceptional Events: Hurricanes and floods
France	Exceptional event as defined by simultaneous interruption of service to more than 100,000 end users; caused by a climatic event whose probability of occurrence is less than 1/20 years
Germany	Interruptions caused externally as a result of elemental natural forces or by actions of third parties (terrorism, war) which cannot be foreseen
Hungary	Exceptional events as defined by service interruptions that affect more than 50,000 customers; caused by system collapse , terror attacks, etc.
Norway	Extraordinary situations defined on a case-by-case basis , but these are not usually excluded from reliability metric calculations
Slovenia	Force majeure: outage caused by a force that exceeds system design limit
Sweden	None
United Kingdom	Exceptional events: weather events that result in more than eight times the daily average fault rate on higher voltages and non-weather related events that are outside of the DSOs control that result in more than 25,000 customers interrupted and/or 2 million customer-minutes lost
United States	Varies by state: IEEE 2.5β; Major Storm Events; Fixed Percentage; events that impact both distribution and transmission

[6] Pacific Economics Group Research LLC, May 2010, “System Reliability Regulation: A Jurisdictional Survey”