

IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events

IEEE Power and Energy Society

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Transmission and Distribution Committee

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USA

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**Transmission and Distribution Committee
of the
IEEE Power and Energy Society**

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Abstract: Reliability of electric power systems remains an important societal issue. While transmission disturbances draw national attention and scrutiny, service interruptions at the distribution level are the primary concern of the end-use customer and their regulatory and governmental representatives. Much effort has been expended in developing methods to uniformly and consistently quantify the reliability of distribution service based on electric system performance. However, the results of a nationwide survey of recorded information used for calculating distribution reliability indices performed in 1998 by the Working Group on System Design (now Distribution Reliability) indicate that significant inconsistencies exist in the data, categorization of that data, and in the collection processes used within the industry. This guide discusses the collection, categorization, and use of information related to electric power distribution interruption events and will be used in the development of industry guidelines. This guide presents a minimal set of data and a consistent categorization structure that, when used in combination with IEEE Std 1366™, will promote consistency in how the industry collects data for the purpose of benchmarking distribution system performance.

Keywords: benchmarking, data collection, IEEE 1782™, outage management systems, power distribution reliability, reliability management, sampling methods

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Introduction

This introduction is not part of IEEE Std 1782™-2014, IEEE Guide for Collecting, Categorizing, and Utilizing Information Related to Electric Power Distribution Interruption Events.

This guide was initiated by the desire of members of the working group to be able to have meaningful comparisons of reliability metrics. This guide was assembled to provide information regarding the collection, utilization, and categorization of information related to electric power distribution interruption events for the specific purpose of system reliability comparisons.

The purpose of this guide is to foster uniformity and consistency of collection of data among utilities in the trending and benchmarking of electric power distribution reliability to enable meaningful assessment of the performance of different electric utilities. In addition, this guide is intended to provide education and guidance with the assessment, trending, and benchmarking practices related to electric power distribution system reliability.

There is an industry need, given the widespread attempts to benchmark and compare electric power distribution reliability and the impact of such comparisons on key stakeholders including end-use electricity customers, utility companies, and governmental entities. The guide will describe recommended data collection, utilization, and categorization practices that should be followed to ensure fair and accurate trending and benchmark comparisons.

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1. Overview

1.1 Introduction

Benchmarking of distribution reliability performance has become commonplace in the electric power industry over the past several years despite the fact that useful comparisons are often difficult to make due to the data collection methods employed, differences in system design and operation, and differences in the environments. Many benchmarking studies have been established, each with its own criteria to define how data should be provided and analyzed. In order to arrive at meaningful conclusions, consistent interruption event data and categorization of that data are desirable (Werner et al. [B9]).¹ IEEE Std 1366™ has defined a methodology that, if used, will provide a common way to segment data.² The purpose of Interruption Reporting Practices Guide is to define data collection procedures. Clearly this is a large topic; therefore, this guide has been broken into the following three issues:

- a) Data consistency and categorization for benchmarking surveys
- b) Data collection within the electric power distribution industry
- c) Data usage and practices

¹ The numbers in brackets correspond to those of the bibliography in Annex E.

² Information on references can be found in Clause 2.

1.2 Scope

This guide provides information regarding the collection, utilization, and categorization of information related to electric power distribution interruption events for the purpose of system reliability comparisons.

1.3 Purpose

The purpose of this guide is to foster uniformity and consistency of collection of data among utilities in the trending and benchmarking of electric power distribution reliability to enable meaningful assessment of the performance of different electric utilities. In addition, this guide is intended to provide education and guidance with the assessment, trending, and benchmarking practices related to electric power distribution system reliability.

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

IEEE Std 1366™, IEEE Guide for Electric Power Distribution Reliability Indices.^{3, 4}

3. Data consistency and categorization for benchmarking surveys

3.1 Overview

This portion of the guide presents suggestions on comparison of utilities based on a high-level categorization of interruption related data. It is not meant to limit how detailed the collection of data could be, or to say what must be collected, rather to define the minimum set of data collection categories required for benchmarking and to give consistency to those categories.

When performing benchmarking studies, the differences between the collection methods, the locations, and the differences in system design can make comparison difficult. Examples of the types of items that may be relevant when performing benchmarking studies are listed below.

3.1.1 Collection methods

A variety of methods available for collecting data, some listed below, could lead to issues when comparing data in benchmarking surveys.

- The differences in the interruption data collection systems (ranging from manually entered paper systems to completely automated computer-based systems)
- The ability to collect interruption data from the system (ranging from the substation level down to the customer service drop)

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- The use, or nonuse, of step restoration when collecting interruption data
- The determination of the start time
- The definition of sustained interruption may play a role (ranging from greater than 1 min to greater than 5 min)
- The definition of a customer (account, meter, premise, etc.)
- Interruption delineations (unplanned interruptions, planned interruptions, major events, etc.)

3.1.2 Location

In some cases, a difference in locale could also lead to issues when comparing data in benchmarking surveys.

- System characterization (rural, suburban, urban)
- Climatic information (hot, cold, wet, dry, lightning, etc.)

3.1.3 System design

In addition, the differences in system design could lead to issues when comparing data in benchmarking surveys.

- System layout (radial, loop, two transformer station, etc.)
- System placement (underground or overhead)

This guide includes a minimal set of data and a consistent categorization structure necessary for comparison of distribution system performance. Presented are categories for system characterization, interruption causes, responsible systems, conditions, voltages, devices, device initiation, and restorations.

3.2 Data collected during the interruption event process

As part of the interruption event collection process, the cause is collected with other pertinent information. This information should include:

- The number of customers interrupted (CI)
- The interruption durations, based on start date/time and restore date/time
- The number of customer minutes of interruption (CMI)

As the database is maintained over the years, cause information can be used in combination with the number of interruption events, the number of CI, and the number of CMI to numerous analytical ends, some of which will be discussed in this document.

3.3 System characterization

It is important to identify the composition of the utilities participating in a benchmarking study. The characterizations of the utility system are usually broken into the three categories below. The categories are defined by the customer's density as shown below.

- a) Rural (less than 31 customers per circuit kilometer or 50 customers per circuit mile)
- b) Suburban (31 through 93 customers per circuit kilometer or 50 through 150 customers per circuit mile)
- c) Urban (greater than 93 customers per circuit kilometer or 150 customers per circuit mile)

Percentages of the number of circuits are applied to each of the categories above to describe the make-up of each utility.

As observed in Table 1 below, a simple system composed of the circuits outlined below should be treated as shown below.

Table 1—System characterization example (percent number of circuits)

	Circuit length (km)	Circuit customers	Customers/circuit length (km)	Circuit designation
Circuit A	14	100	7	Rural
Circuit B	50	2000	40	Suburban
Circuit C	12	1500	125	Urban
Circuit D	20	500	25	Rural
Circuit E	27	1000	37	Suburban
	Urban	Suburban	Rural	
Percent of circuits with system designation	20%	40%	40%	

3.4 Interruption cause categories

Ten general interruption cause categories are suggested for comparison in benchmarking studies. These are intentionally broad categories that will make possible more precise benchmark comparisons between different distribution utilities. There are numerous categories that could be chosen, but with the goal of uniformity for comparison purposes, the following ten categories were chosen:

- a) Equipment
- b) Lightning
- c) Planned
- d) Power supply
- e) Public
- f) Vegetation
- g) Weather (other than lightning)
- h) Wildlife
- i) Unknown
- j) Other

The recommended categories do not prevent a utility from collecting more detailed data, and that is indeed encouraged. However, the data collected should be able to be placed into one of the ten categories recommended.

The following paragraphs describe the types of interruptions that should be put into each category. Of course, not every possible interruption can be discussed; but for most interruptions, the choice of category is apparent. The cause categories are discussed in the order as presented above.

- a) Equipment—Any piece of the distribution system equipment that is defective or fails and causes an interruption to customers should be put in the equipment category. A few examples of equipment types include controls, conductors, insulated transitions, interrupting devices, arresters, structures and supports, switches, and transformers.

- b) **Lightning**—The lightning category includes all interruptions caused by lightning. This may be by a direct stroke contacting the wires or another piece of equipment, or by a lightning-induced flashover of the wires or another piece of equipment.
- c) **Planned**—The planned category includes, but is not limited to: Road construction, maintenance and repairs, load swaps, replacing equipment, and house moves. Typically, planned interruptions are those interruptions that can be delayed by the utility personnel and performed only after the appropriate or required customer notification. Often, regulatory commissions have specified rules describing planned interruptions.
- d) **Power supply**—The power supply category includes interruptions caused by a failure in the transmission system including the transmission portion of a substation or the loss of a generating unit including those associated with distributed generation. It does not include outages due to the loss of a distribution substation component.
- e) **Public**—Any interruptions resulting as an act of the public at large should be put into the public category. Examples include: customer trouble, non-utility employee or contractor dig-in, fire/police requests, foreign contact (such as Mylar balloons, crane boom, and aluminum ladder), traffic accidents, vandalism, and fires and explosions not originating on or within utility-owned equipment.
- f) **Vegetation**—The vegetation category includes interruptions caused by falling trees or limbs, growth of trees, vines, and roots. It should be emphasized that if a tree is involved, the cause category is vegetation. This is important to note during wind storms. It may not be possible to determine that a feeder may have a forestry issue if wind is listed as the cause when actually a tree was involved.
- g) **Weather**—The category of weather should include interruptions due directly to a weather phenomenon including: wind, snow, ice, hail, and rain where the weather itself caused the interruption and exceeded the system's design limits. Wind does not include slapping or galloping conductors; those would go under the equipment category. Ice forming on conductors and tearing them down or flooding of power facilities would be included in the weather category.

NOTE— If any part of a tree is involved, it would go under the vegetation category.⁵
- h) **Wildlife**—This includes mammals, birds, reptiles, and insects, or any other non-human member of the animal kingdom. Wildlife can cause interruptions directly through contact, like snakes, mice, ants, raccoons, squirrels, or birds; or indirectly, like nests and bird excrement.
- i) **Unknown**—The unknown category includes any customer interruptions where a definitive cause cannot be determined after investigation. The level of investigation required is determined by the individual utility.
- j) **Other**—Any interruptions to customers that do not fall into any of the other cause categories should be assigned to the other category. Some examples include: errors in construction, maintenance, operating, or protecting; overload; and contamination.

3.5 Responsible system

When participating in benchmarking studies, it is useful to know the responsible system. This is defined as the portion of the system in which the fault initiated. There are several responsible system categories. These include:

- a) Distribution overhead
- b) Distribution underground

⁵ Notes in text, tables, and figures of a standard are given for information only and do not contain requirements needed to implement this standard.

- c) Generation
- d) Substation
- e) Transmission
- f) Customer equipment

The customer equipment category refers to customer-owned equipment that is an integral portion of the utility's system, and when a fault occurs on the customer owned equipment, it causes interruptions to one or more of the utility's other customers.

3.6 Conditions

The categories under conditions refer to conditions at the time of the interruption. Many times the condition may be a contributing factor to the number of customer interruptions or the time it takes to restore customers. The conditions may play an important role when analyzing benchmarking data. The proposed condition categories include:

- a) Routine (day-to-day)
- b) Major event

Routine is defined as daily conditions that do not constitute a major event day. A major event day is defined by IEEE Std 1366™ in the major event day definition. These designations would have to be added to the interruption data after the determination that a major event occurred.

Additionally, individual utilities may choose to collect other conditions, such as weather, that were present during the time of the interruption event. For example, each utility could develop a list of weather conditions based upon local climate.

3.7 Voltage level

In some benchmarking studies, information is provided using typical voltage classes (phase-to-phase) as shown in the list below. The voltage information for a customer interruption event should be based on the highest voltage level affected.

- a) Secondary/Low voltage
- b) 5 kV
- c) 15 kV
- d) 25 kV
- e) 35 kV
- f) >35 kV
- g) Transmission

3.8 Interrupting devices

Benchmarking studies may review the type of interrupting devices used, their failure rates, how many operations occurred, and the total number of devices deployed. Interrupting device is the device that initiates the start of the customer interruption. The following is the recommended list of categories of interrupting devices.

- a) Circuit breaker/substation recloser
- b) Fuse
- c) Line recloser
- d) Sectionalizer
- e) Switch
- f) Other

The following discussion centers on which particular devices should be put into each category. Of course, not every possible device can be discussed. The circuit breaker/recloser category should include circuit breakers and reclosers found in substations and those used for protection of entire feeders/lines. The fuse category should include line, tap, and transformer fuses. Reclosers located along a circuit/line should be in the line recloser category. Gang switches and blade disconnects are captured in the switch category. Any other interrupting devices not covered by the first five categories, including an open conductor, are grouped under the “other” category.

3.9 Interrupting device initiation

Another analysis of interrupting devices may include the manner in which they operated when they were opened and closed. These operations can fall into the following recommended categories:

- a) Automatic
- b) Manual

“Automatic” includes all operations without human intervention. “Manual” is any operation that involves personnel to operate the device, whether at the location of the device or from a remote location.

3.10 Customer restoration

Benchmarking studies may analyze how customers are restored after experiencing an interruption to power. There may be several ways to reenergize customers after an interruption. The suggested categories are as follows:

- a) Automatic substation transfer
- b) Automatic circuit sectionalizing
- c) Manual circuit sectionalizing
- d) Left disconnected
- e) Reenergized at station
- f) Repaired defective equipment
- g) Replaced defective equipment
- h) Replaced fuse
- i) Reset transformer breaker
- j) Installed temporary

The first category, automatic substation transfer, includes any scheme that transfers customers to an alternate supply in the event that their primary supply is interrupted. This scheme operates without any

human intervention. “Automatic circuit sectionalizing” refers to any automatic schemes outside the substation that transfer customers experiencing a power interruption to another energized circuit segment either on the same circuit or a different circuit. “Manual circuit sectionalizing” refers to any action taken by field personnel or remote operation by an operations supervisor to transfer interrupted customers to other feeders/circuits. This also includes resetting midline reclosers and operating switches to reenergize interrupted customers to another part of the same feeder/circuit. In some cases, customers will not be put back in service due to fire, flood, or some other destructive force that destroys the entity requiring power. In this case, “left disconnected” is the category.

Sometimes a feeder/circuit is locked out at the station and no cause is found. The circuit breaker or recloser is closed again (reclosed), and if it holds, the category “reenergized at station” is chosen. It may also be used for transformer or bus outages in the station. The last five categories are self-explanatory.

3.11 Equipment failure or deterioration

Benchmarking studies frequently examine equipment performance as well. This equipment is usually failed equipment that initiated the customer interruption. Typically, pieces of equipment are grouped into different categories. Data collected may be by number of interruption events, number of customers affected, or by duration of the interruption. Results from this data may reveal rates of failure for various types of equipment, if some utilities have a problem with a type of equipment as compared to other utilities, and how the use of equipment varies from one utility to another. The following is the recommended list of categories of equipment.

- a) Cable
- b) Wire
- c) Connector
- d) Control
- e) Insulated transition
- f) Interrupting device
- g) Lightning/surge arrester
- h) Other equipment
- i) Structural support
- j) Switch
- k) Transformer

The “cable” category includes all cable that is direct buried or placed in pipe or conduit or U guard. “Wire” refers to overhead strung conductors and jumpers. Connections, splices, and other hardware are not included in these two categories. The “connector” category includes connectors, insulinks, splices, etc. The “control” category contains relays, smart meters, and other control equipment. “Insulated transition” is comprised of bushings, insulators, separable connectors, polymeric terminations, potheads, stress relief cones, etc. The “interrupting device” category consists of circuit breakers, reclosers, and fused equipment. The “lightning/surge arrester” and “other” categories are self-explanatory. “Structural support” category includes anchors, poles, towers, cross arms, braces, etc. The “switch” category contains disconnect, isolation, and load break switches; solid-blade cutouts; etc. The last category, “transformer,” can include auxiliary, current, distribution, grounding, potential or voltage, power, rectifying, step-down/conversion, and voltage regulating transformers.

4. Data collection within the electric power distribution industry

4.1 Overview

It is generally accepted that in today's operating environment, utilities need to accurately capture information regarding the number of service interruptions, their duration, and the number of customers affected (Robinson et al. [B2]). Most utilities, including investor-owned, municipal, and co-operative utilities, have realized the need to capture equipment outages and the resulting customer interruptions; nearly all capture sustained interruptions. The methods and approaches vary widely depending on the existence and sophistication of installed information systems such as the customer information system (CIS), the geographic information system (GIS), the supervisory control and data acquisition system (SCADA), and the outage management system (OMS). In general, a utility's interruption reporting system uses key information from these systems to improve the completeness and accuracy of reliability information.

Comparing reliability statistics between utilities is a difficult task because of so many factors, not the least of which is differing data collection processes and procedures. During the benchmarking process, it is imperative that consideration be given to the level of data collection and the state of implementation of these systems and their associated processes. Even among utilities that have similar systems, such as an outage management system from a specific vendor, performance differences are likely to occur, due either to customization for an individual utility and/or process differences, and those differences may be significant. Without such consideration, comparison of performance will be inexact.

4.2 Manual collection systems

Typically, a utility with paper maps and little or no connectivity records will utilize a fully manual collection approach. Field personnel estimate the number of customers affected during a service interruption. Utilities couple these estimates with an estimate of the beginning time of the service interruption to determine the impact of each event on customers. This approach may be the least accurate approach of the methods that will be discussed in this guide. It is the one that forms the starting point for most utilities in their evolution to a fully connected system, as most utilities began collecting reliability performance information as a consequence of building a system to assist with quicker power restoration.

The data collected with these systems helps that utility identify and track areas on the systems that have reliability concerns. These concerns could include repeated interruptions and potentially poor customer satisfaction. Generally, the manual reporting system tracks only sustained interruptions and does not record the momentary interruptions. In utilizing this method, step restoration efforts are very difficult to track properly; specifically the customer minutes of interruption are not reduced correctly.

Without a fully connected model that provides the connectivity of each customer to the protective devices upstream on the feeder, utility staff must manually group individual customer calls (tickets) by area and then provide this information to field personnel for restoration. Using this approach may result in customers supplied through different devices being grouped together incorrectly, thereby extending the restoration time. In this case, the field personnel have to contact each customer to make sure everyone is restored with the resolution of the outage. If it is assumed everyone in the area has had service restored, then some customers may need to call back to report their continued interruption.

Typically, the interruption records are manually entered into a spreadsheet, or database, and are maintained as time allows, by available personnel, with varying degrees of timeliness. Most of these systems allow free-form text entry, thereby introducing errors into the system merely from the act of recording the data. Further, the level of detailed information captured for each interruption will be limited and may not always

include such information as the cause, the device affected, the location, and a variety of other useful types of information.

With the manual system, the input from field personnel tends to vary greatly in that they are based solely on the individual field worker's best estimate, which can be made as conservative as desired to provide an overly optimistic, or pessimistic, result. Again, the nature of this type of approach provides only general trends and should be used by the utility for internal comparison and not used to benchmark performance with other utilities unless the results are clearly identified as having been generated with a manual system.

4.3 Fully automated outage system

At the other end of the interruption data collection spectrum are systems that utilize a full connectivity model from customers to transformers, to lateral protective devices, to main line protective devices, and finally back to substation protective devices (i.e., breakers) and in some cases even through the substation and into the transmission system. In these advanced systems, the outage management system (OMS) is often based on a complete geographic information system, and in some cases, may include information provided by a real-time substation device outage reporting system via SCADA. With this fully integrated system, the utility has the potential to have an accurate count of the number of customers affected by each outage as well as the duration of each interruption of service. Beyond installing these systems, utilities must educate employees to ensure that personnel are properly operating all the new systems and understand the impact of their actions. The process is equally as important as the information technology system in obtaining accurate reliability information.

Using such systems allows for the provision of timely results of system performance metrics and performance trending. Analysis may be performed down to specific devices; in some cases to the individual customer level. With the full customer connectivity model, utilities not only will have more accurate information to build their reliability statistics, but they will have the ability to automatically group or combine individual customer calls to specific transformers or fused laterals and thereby minimize the number of tickets or equipment outages being investigated at one time. Once the problem has been resolved and the device restored, all of the customers supplied through this device are considered restored. The connectivity model allows the utility to account for the partial, or step, restoration of portions of the feeder and correctly identifies the duration of interruption experienced by each customer throughout the restoration activities.

Most utilities that have implemented a more accurate and sophisticated connectivity model and outage management system have found that their reliability statistics appear to have deteriorated. In many cases, the new systems enable full accounting of the number of customers affected by each service interruption as well as the service interruption duration because accurate start and end times for the interruptions are captured. Rather than being considered a reason to not implement such a system, the more accurate methods will provide many capabilities for the utility to develop a better picture of problem areas and the comparable magnitude of the problems for prioritization. Furthermore, these systems will help the utility optimize its spending and meet the challenges of ever increasing regulatory and customer scrutiny.

4.4 Implementation of various outage systems

The current technologies, systems, and processes used by different utilities are based on various drivers that are utility-specific and are the result of many years of operation. Until the widespread availability of outage management systems in the 1990s, it was considered adequate to operate based on a manual system. As more public service commissions and customers demanded better data, utilities have requested the development of advanced systems that they could implement. Many of these systems cost millions of dollars and take years to implement. No matter the reason for improvements in the components of the

company's outage management process, the utility should build on these advancements to provide improved accuracy and response time.

As a utility considers system enhancements to its mapping, customer information system, facilities tracking, work management, or other related systems, it should consider the added benefits and improvement that can be achieved by building up or integrating these systems with an outage management system/process.

All outage management systems rely on several key components:

- Connectivity model from customer to supply, ranging from:
 - 1) A link between transformers, devices, and customers
 - 2) A full and accurate GIS model, including phasing
- Customer interruption reporting from:
 - 1) Customer service representative contact
 - 2) Interactive voice recognition unit (IVR)
 - 3) Web applications supporting interruption reporting
 - 4) Automated outage reporting device
- SCADA
 - 1) Substation automation devices
 - 2) Distribution automation devices
- Automatic meter reading outage reporting
- Outage event report analysis or grouping capabilities, i.e., group by customer, transformer, or protective device
 - 1) Via hard copy outage tickets
 - 2) Via electronic database with input:
 - i) Via mobile data terminals
 - ii) Via manual incident entry

All of the above key components of an outage management system can be provided in many different ways, with varying levels of completeness and accuracy. Most utilities find when they implement more sophisticated models or systems, their reliability statistics worsen due to increased accuracy of data collection.

The need to have accurate maps in electronic format can be a driver for implementing new or improved interruption collection processes. With the implementation of a geographic information system (GIS), the utility can utilize this information to further improve its connectivity model and outage management process. The cost justification for the GIS, and the outage management system, is the ability to utilize the added benefits of these systems working together to improve utility efficiencies and customer service.

On the other hand, for those utilities that do not currently have or cannot justify the purchase and implementation of a GIS, establishment of the connectivity by itself may be justified based on the outage call grouping functionality that can improve the efficiency of the dispatch personnel and reduce outage restoration times.

Gathering the outage information in a timely manner is key. Even the most sophisticated, fully-computerized OMS can only analyze and group the customer interruptions entered into the system. If there

is a limit in the number of customer calls that the customer service representatives or IVR systems can enter in a given period, or, the outages calls entered are scattered throughout the territory, the OMS may not reduce the number of tickets or trouble orders for dispatching and tracking. Utilities with limited interruption reporting capabilities may easily be able to cost justify funding for an increased number of customer service representatives, or implement an IVR system.

Further, as utilities improve their connectivity model and outage reporting methods, more emphasis can be made to justify expanding their outage management system capabilities. The OMS can either be developed in-house by the utility or obtained from an OMS provider that can best utilize the utility's existing connectivity model and outage reporting processes. Purchasing a packaged OMS will probably provide the utility with included capabilities that have not been considered in-house but, as a package, can be incorporated into the cost justification for the purchase.

As each utility deals with the key components, it needs to consider the overall importance of each function to the utility and focus funding to any of the components that, if not implemented, will limit the process from meeting the utility's operations and customer reliability requirements.

4.4.1 Evaluating the impact of outage management process changes

Upon implementation of an automated outage management system, indices are likely to change reflective of the differences in measuring outage events. Thus, while index levels may indicate deterioration, this is generally the result of collecting data which was not previously collected or may reflect more accuracy in the collection process. A variety of methods have been implemented to try to measure the effect of the process change. Two specific approaches are discussed below.

4.4.1.1 Before and after OMS comparison results: OMS uplift correlations

An example approach, OMS uplift correlations, is shown below. It can be used for evaluating the impact of outage management reporting "discipline," or an automated outage management system is shown step-by-step below.

First, the prior system daily performance is assembled. Pre-arranged and customer requested outage causes were removed from the dataset. Next, the post-implementation system daily performance is assembled. Both datasets were reviewed to determine whether any "outlier" events had occurred using the application of the 2.5 beta daily screening (consistent with the method for determining the existence of a major event). For days that reached that level, they were separated out. The remaining days were summarized on a monthly basis, and trouble calls (tc) summarized for the same days and months. Trouble calls were correlated to customer interruptions and customer minutes of interruption, as shown in Table 2. Within Figure 1, visual assessment of the tabular data is depicted, whereby the OMS impact on metrics is visible. This may be considered a form of reporting "uplift." That is to say, while the system fundamentally performed the same, the impact of process results in apparently different performance metrics. In Figure 2, uplift that can be attributed to reporting discipline is shown, as is uplift attributable to network connectivity and outage management system processes.

Several key assumptions exist with this approach. First, it is assumed that there is no substantial change in real reliability before and after implementing these process changes, therefore any known improvements to the system could yield false conclusions, and need to be accounted for. Thus, if implementation occurred at a point in the year where reliability fundamentally alters (i.e., the summer for a summer-stressed system), this assumption would need to be corrected. Second, it assumes that customer trouble reporting processes before and after are materially the same. If any changes to customer call patterns could be expected (which could be due to local news, changes in call handling, changes in call centers or business offices, etc.) this assumption would likewise need to be corrected. Third, an assumption is made that outage duration, both

before and after system changes, is also approximately equal. If it is expected that a change will occur (either to lengthen or shorten duration), this needs to be factored into the calculations and correlations.

Table 2—Comparative data for assessing OMS uplift

	Trouble Calls	SAIDI Minutes	SAIFI Events	Sustained Outages	Customer Minutes Interrupted	Restated Trouble Calls	Restated SAIDI Minutes	Restated SAIFI Events	Restated Sustained Outages	Restated Customer Minutes Interrupted
Aug	1 048	12	0.13	382	556 219	1 048	12	0.13	382	556 219
Sep	481	14	0.10	325	647 933	481	14	0.10	325	647 933
Oct	384	7	0.10	245	342 794	384	7	0.10	245	342 794
Nov	267	2	0.03	138	108 734	267	2	0.03	138	108 734
Dec	333	9	0.10	158	417 303	333	9	0.10	158	417 303
Jan	414	23	0.42	157	1082 503	243	3	0.02	86	122 325
Feb	197	16	0.16	115	728 053	148	6	0.05	93	261 612
Mar	224	5	0.08	135	212 855	224	5	0.08	135	212 855
Apr	519	16	0.13	232	904 337	519	16	0.13	232	904 337
May	678	26	0.36	398	1435 332	678	26	0.36	398	1435 332

Correlations Used to Restate	
outages vs saidi post	outages vs tc post
0.75	0.83
SAIDI	
average pre saidi	8.12
average post saidi	15.85
uplift factor	1.95
SAIFI	
average pre saifi	0.10
average post saifi	0.18
uplift factor	1.86

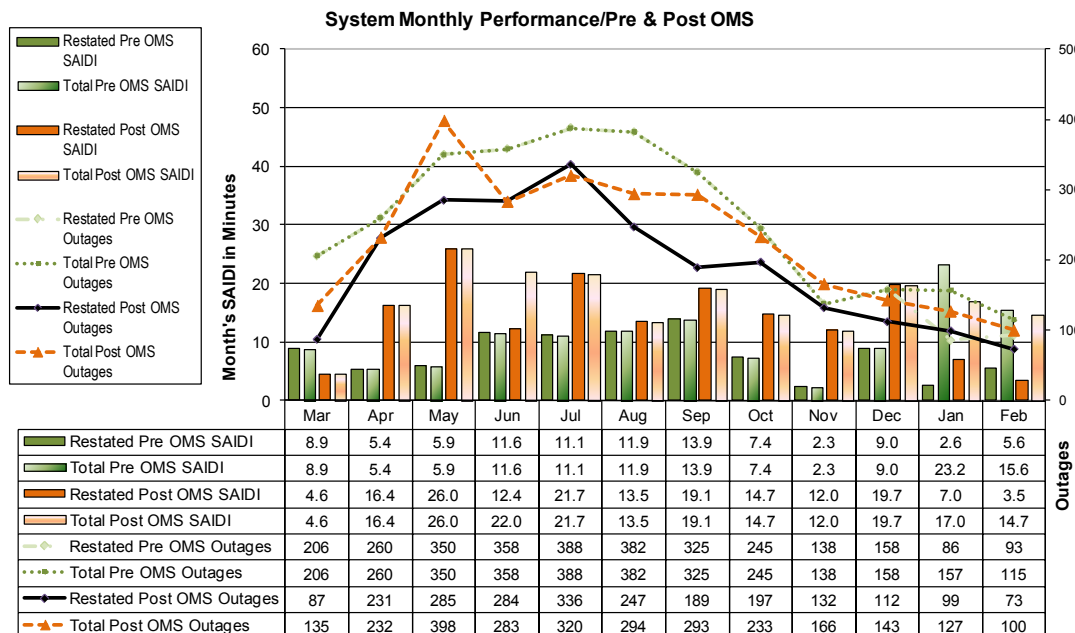


Figure 1—Monthly comparison of pre- versus post-OMS implementation: monthly SAIDI and outages

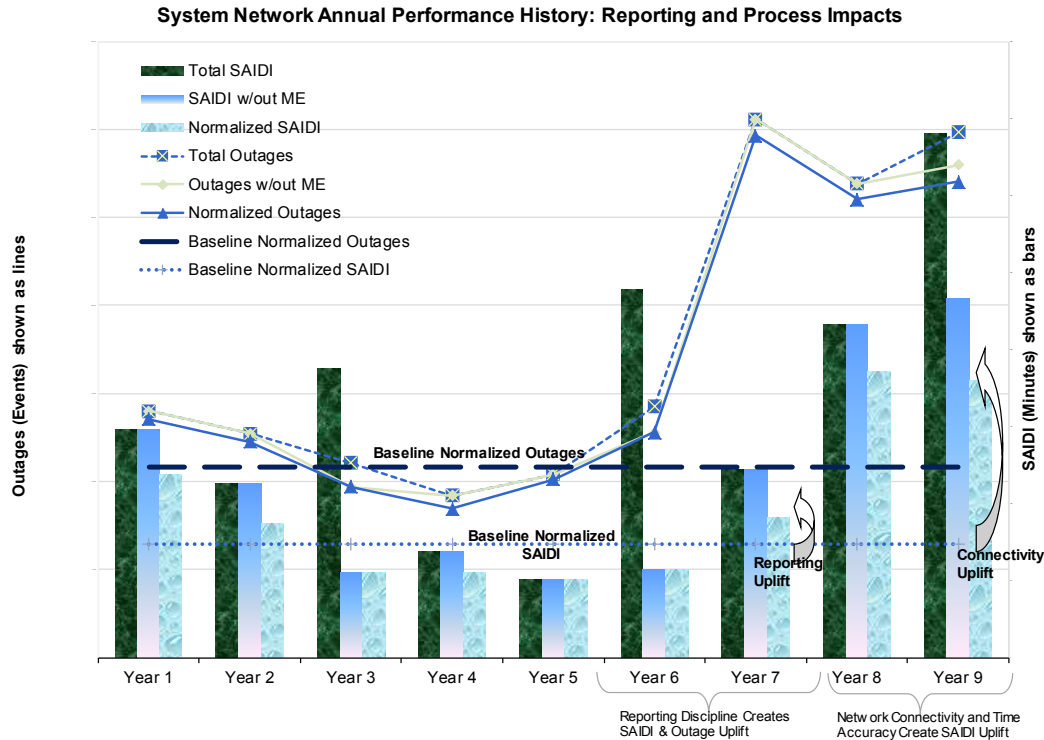


Figure 2—Summary performance history of pre- versus post-uplifted performance: SAIDI and outages

4.4.1.2 Before and after OMS comparison results: “incrementing averages”

Another method of evaluating the impact of system reporting changes, incrementing averages (Bouford and Warren [B1]), is shown in Table 3. It is founded on the premise that incrementing into a historical period, one will be able to discern the tendency of the system, whether it is based on an actual change in performance or on a change in the underlying measurement system. The running average, also called the cumulative moving average, is an unweighted average of the sequence of i values $x_1, \dots, x_i$ up to the current time, and the formula can be written as $Ca_i = (x_1 + \dots + x_i) / i$. The brute force method to calculate this would be to store all of the data and calculate the sum and divide by the number of data points every time a new data point arrived.

To use the method of incrementing averages, the running averages of annual performance are calculated through the period of record by incrementing each start year. This running average calculation is displayed in Figure 3 where there are 11 years, which are then plotted as 11 running averages as shown in Figure 5.

Table 3—Annual performance to calculate incrementing averages uplift method

SAIDI (min)	Running avg	Yr	Yr 11 start incr'd avg	Yr 10 start incr'd avg	Yr 9 start incr'd avg	Yr 8 start incr'd avg	Yr 7 start incr'd avg	Yr 6 start incr'd avg	Yr 5 start incr'd avg	Yr 4 start incr'd avg	Yr 3 start incr'd avg	Yr 2 start incr'd avg	Yr 1 start incr'd avg (same as running avg)
57.6	57.6	1											57.6
56.1	56.9	2										56.1	56.9
73.1	62.3	3									73.1	64.6	62.3
67.8	63.7	4								67.8	70.5	65.7	63.7
60.7	63.1	5							60.7	64.3	67.2	64.4	63.1
41.0	59.4	6						41.0	50.9	56.5	60.7	59.7	59.4
74.3	61.5	7					74.3	57.7	58.7	61.0	63.4	62.2	61.5
67.0	62.2	8				67.0	70.7	60.8	60.8	62.2	64.0	62.9	62.2
79.9	64.2	9			79.9	73.5	73.7	65.6	64.6	65.1	66.3	65.0	64.2
73.1	65.1	10		73.1	76.5	73.3	73.6	67.1	66.0	66.3	67.1	65.9	65.1
92.1	67.5	11	92.1	82.6	81.7	78.0	77.3	71.2	69.7	69.5	69.9	68.5	67.5

A first approach with this data is to look at an average across the entire period using the running average calculations for the first year as shown in Figure 3. The SAIDI for this company appears to be gradually deteriorating; however, no clear conclusions as to the reason can be drawn from this chart. Another way to approach the data is to gradually factor into the analysis more of the years of history as calculated in Table 3 and depicted graphically in Figure 4.

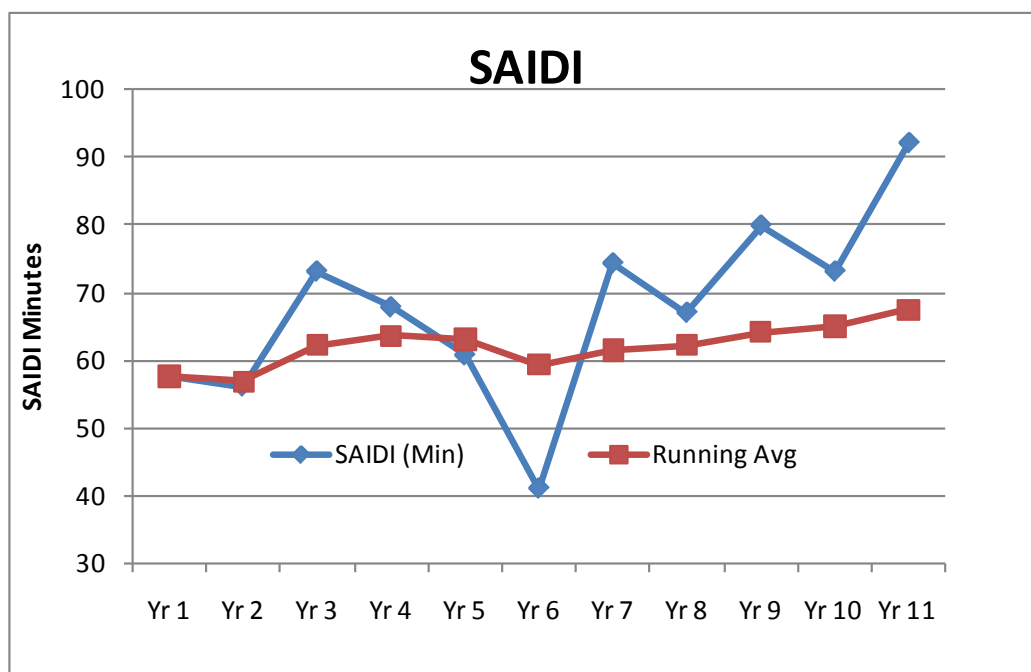


Figure 3—Running average SAIDI

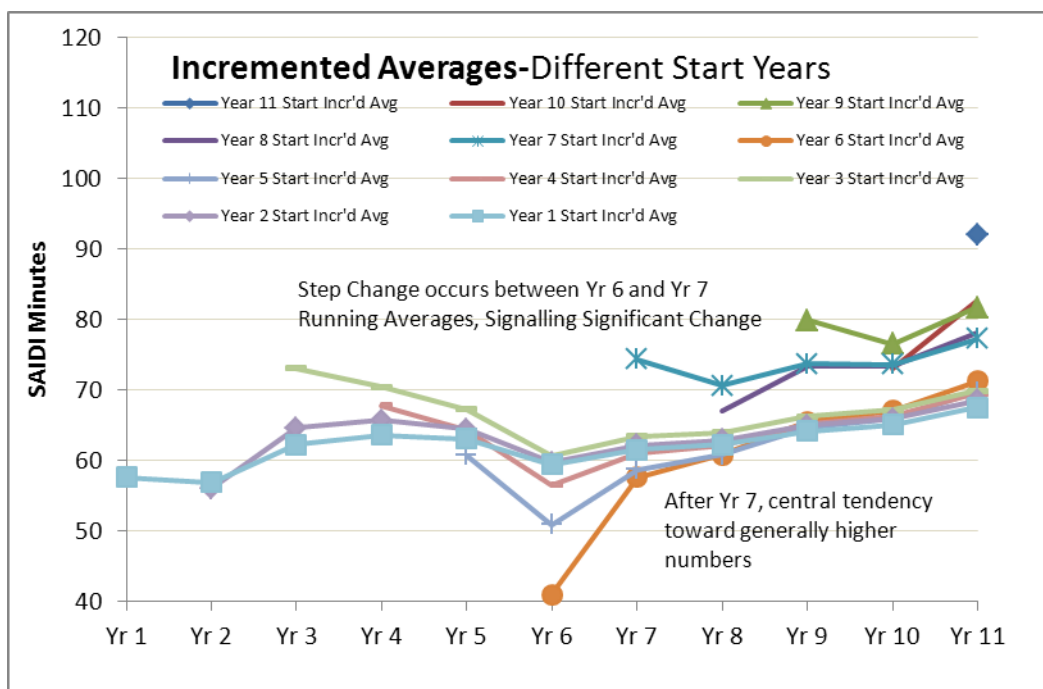


Figure 4—Incremented average SAIDI—different start years

When a substantial step increase occurs in a time series so that the average for the data after the increase is significantly different than that prior to the increase, two distinct groupings will appear when incrementing averages are applied. The magnitude of the increase in the resultant metric value can be determined by the percent difference between the averages of these two groupings of incrementing averages. When the values in the years affected by the introduction of the new data collection system are reduced by the percentage difference of the averages of the two groupings, any other factor affecting the increase will be shown in the plotting of the incrementing averages. The method will also clearly show not only the impact of changed processes/systems but also any system deterioration affects. These may be due in part to weather or other external factors.

Rather than a simple running average, a method of incrementing averages is applied to the data. This is done by incrementing the start year for a series of running averages of the SAIDI values. Figure 5 shows the results for one utility's data set. Each data point on a specific line represents the average from the start year of that line to the year represented by that data point. For example, on the light green line, the first point is the SAIDI for year 3, while the fourth point is the average from year 3 to year 6.

For the years prior to year 7, the incremented averages “track” toward the same value range through year 7, approximately 63 minutes. Even the incrementing averages starting in year 3, year 4, and year 5, which are greatly affected by the outlier value of year 6, trend toward the average of the year 1 through year 6 data set. This can be seen as a grouping of the averages at the year 7 point.

The incremented averages for post-year 6 start years are demonstrating a marked difference in value; they are tracking toward a very different value range than the pre-year 7 values. The post-year 6 averages appear to track toward approximately 78 minutes. For the subject utility, an OMS was implemented in year 7. For many utilities, this will result in a more complete dataset of outage events, more accurate calculations of customer minutes of interruption, and more certainty of the number of customers interrupted in each outage event. What is being shown by this action of the incrementing averages is that the post-year 6 data set has a different, and higher, average value than the pre-year 7 data set. It appears that the introduction of the OMS has caused the SAIDI values to be higher by some rather constant amount. The two distinct data sets have established separate groupings of their incrementing averages for this evaluation period. If the incrementing averages were carried forward for enough years, all the incrementing averages would merge to the average