Evaluation of Data Submitted in APPA's 2018 Distribution System Reliability & Operations Survey

NOTE

American Public Power Association staff has used a high degree of care in developing this report. However, APPA does not accept any liability resulting from the use of this publication or from its completeness and fitness for any particular purpose.

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INTRODUCTION

The 2018 Distribution System Reliability and Operations Survey was developed by the American Public Power Association (APPA) to assist members in their individual efforts to understand and analyze the issues that arise from maintaining and operating an electric distribution system. By asking members to identify and document existing reliability and operations-related metrics, the survey intended to shed light on general factors used by different utilities in their decision-making processes. Since the type of data collected in the survey is not commonly available to utilities, this report intends to serve as a supplemental tool to expand industry-wide understanding of the operations, procedures and practices that lead to distribution system reliability.

This report does not address reliability of the bulk power system. The bulk power system is defined by the Federal Energy Regulatory Commission and is subject to reliability standards established through the North American Electric Reliability Corp. (NERC).

In many cases, municipally owned utilities are not subject to federal or state laws regarding the reliability of their distribution systems. This makes decisions regarding utility distribution system operations and the resultant degree of reliability inherently local. To help members understand the technical issues surrounding reliability in more detail, APPA publishes and sells several tools such as, the eReliability Tracker Service. These products focus on the practical aspects of operating a distribution system and have served as a good starting point for many electric distribution reliability programs. The general information on distribution system operations contained in this report is designed to provide municipal electric utilities with a broader base of knowledge for formulating easy-to-administer and sound day-to-day practices.

Each section of this report summarizes survey results with graphics that illustrate how participants responded to any given question. The organizational flow of the report corresponds to the order of questions as they appeared in the survey (a copy of the survey questionnaire is included in Appendix A).

In the survey, there were calls for certain confidential or proprietary information that may be sensitive. All responses included in this report have been aggregated to ensure confidentiality.

DISCUSSION

The discussion in this report strives to set the context for understanding the analysis of data presented and addresses a few of the fundamental questions surrounding distribution system reliability.

SYSTEM RELIABILITY

Reliability, from a system engineering perspective, is the ability of an electric system to perform its functions under normal and extreme circumstances. Reliability indices help engineers and other operations personnel understand and demonstrate the interconnected nature of the many independent system components that make up an electric distribution system. This connection makes apparent the fact that overall system design, including construction practices, impacts fundamental reliability. From substation and distribution design to fusing schemes, various physical factors of system design impact system reliability.

Among the commonly considered factors are: system voltage, feeder length, exposure to natural elements (overhead or underground conductor routing), sectionalizing capability, redundancy, conductor type/age, and number of customers on each feeder.

Since resources are typically limited, reliability-related system improvement decisions involve trade-offs. In some cases, improving system redundancy is the most important enhancement that can be identified through reliability studies. Additional redundancy can lead to resiliency, or the ability to withstand and/or recover from larger shocks to the system, which can improve reliability numbers during extreme events and catastrophes. In preparation for these events, key engineering-level tradeoffs are made between cost, transport efficiency (e.g. line-losses), and fault tolerance.[1] Knowing where to start when making these important decisions can be a difficult task. At a utility where reliability indices are collected, engineers and/or other operations personnel will have better data to help choose a reasonable starting point for improvement.

When designing lines, utility staff constantly consider the trade-offs involved. For instance, when looking at line voltage, if an engineer decides to use a lower 4-kilovolt (kV) line voltage, he or she may experience fewer outages from line contact with vegetation. However, with lower voltage, the thermal line losses will be greater and the system will be less thermally efficient. On a line designed to operate in a higher 25-kV range, thermal line losses will be reduced, but a vigilant tree trimming program will be required to reduce the increased potential for ground fault by contact with vegetation. Reliability data can help an engineer make these types of decisions by revealing potential areas of improvement. Operations personnel are also challenged to address the negative influence of weather-related variables like ice, wind, and heat.

Power quality is another important aspect of reliability. Typically described in terms of voltage flicker, transient sag and swell, harmonic duration of currents or power quality is a significant concern for utility engineers. Delivery of high-quality, flicker-free power is especially important to many large industrial loads. A momentary interruption can cause electronic industrial equipment to trip off, leading to costly production losses. To improve the power quality and reliability for industrial customers, a utility may track

[1] Atsushi Tero, Et al. Rules for Biologically Inspired Adaptive Network Design, Science, Jan 2010

its voltage transients and employ transient voltage surge suppression, VAR support, or other remediation. There are several resources available to help with this task.[2,3]

RELIABILITY STATISTICS AND THEIR USES

Reliability statistics are the quantitative basis for good decision making and come in many forms. Overall, reliability statistics are excellent for self-evaluation. That's not to say utility-to-utility comparisons cannot be made, but differences specific to each electrical network, such as weather conditions, number of customers served, customer willingness to pay for reliability, and equipment used, limit the value of such comparisons. Some regulators take the perspective that standardized metrics are paramount for cross-utility comparison. While such comparisons have benchmarking value, the metrics are most useful when examined from period-to-period (week, month, or year) for a single electric system. The data can help each utility make the best decision possible in light of its specific circumstances.

STARTING POINTS FOR RELIABILITY

When evaluating utility reliability, a good place to start is with the industry standard metrics found in the IEEE 1366 guide. These metrics were designed by utility personnel to be an integral part of the framework for internal reliability benchmarking and external utility comparison. To benchmark internally or externally, statistics should be collected and evaluated for at least five years. After review of the 1366 document and its metrics, a utility may find that not all of the calculations it recommends will help in making better decisions. Where this occurs, it is important to decide which metrics would be best for your utility's particular circumstances.

The IEEE 1366 guide was developed to help create a general, uniform and understandable set of metrics for measuring electric distribution system service reliability. IEEE standards are tools to help guide decision making. They are developed as consensus documents by the IEEE societies and approved by the American National Standards Institute (ANSI). Due to the disagreement over the best ways for utilities to track and report reliability data, it took many years of debate before the first 1366 standard was released in 1998. The most current standard was released in 2012. It is important to note that the 1366 standard is not a design standard. In addition, the standard acknowledges that some utilities may not possess the tools necessary to calculate some of the indices. To help small utilities with reliability metrics, APPA provides a service called eReliability Tracker[4]. In addition, APPA's Demonstration of Energy and Efficiency Developments (DEED) program offers members the opportunity to apply for research-related grants, which could help small or large utilities in their efforts to advance public power technologies in all areas, including reliability.[5]

Calculating reliability metrics is a part of the pathway to continued exceptional performance. APPA's RP_3 (Reliable Public Power Provider) program designates 25 percent of its points for reliability. The growing number of utilities applying to this program shows increasing utility interest in tracking and establishing reliability indicators based on sound metrics. APPA staff highly recommends getting involved in the RP_3 program. For more information regarding the program, visit www.PublicPower.org/RP3.

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[2] IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems, IEEE Std 142-2007

[3] IEEE Guide for Identifying and Improving Voltage Quality in Power Systems, Revision of IEEE Std 1250-1995

[4] Visit the eReliability Tracker website for more information: http://www.publicpower.org/reliability

[5] Visit the DEED website for more information: http://www.publicpower.org/deed

WHY RELIABILITY INDICES?

Reliability indices are significant components of any utility's ability to measure long-term electric service performance. The 1366-defined indices have a general level of acceptance, which makes them useful as benchmarks and as long-term average system performance measures. The idea is that indices, such as the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), Momentary Average Interruption Frequency Index (MAIFI), and Average System Availability Index (ASAI) provide a comprehensive indicator of the total reliability of a utility's electric distribution system when viewed holistically. For definitions of SAIDI, SAIFI, CAIDI, MAIFI, and ASAI please see Appendix B.

WHAT DOES A NUMBER MEAN IN THE CONTEXT OF RELIABILITY INDICES?

Reliability metrics are one indicator of system health or condition. The same way many complex systems have their own level of health, these indicators let a utility know if the system is getting better or worse over time. Since all systems are different and stressed by different factors, it can be very hard to make a legitimate comparison between two systems. This means reliability indices are situational in nature and will present different baselines depending on the many intrinsic factors affecting the system.

There are differing philosophical approaches to the collection of reliability data. For example, a utility manager under the philosophy that all outages can be addressed or minimized may choose not to remove any outage events while computing indices. This approach has some merit. It allows higher emphasis on post-storm restoration and puts more accountability for restoration after major events on the utility manager. Alternatively, the IEEE 1366 standard strives to allow managers to remove major event days and analyze them separately from the other normal 99 percent of the data set. However, when it comes to getting the lights back on, allowing large events to be treated differently in terms of management response comes with its own set of hazards. It may be useful to use both types of reliability measurements: removing the major events in long-term analysis and including them, where possible, with descriptions, for a detailed look at the way a utility handles its major events.

Since there are different methodologies for extracting and calculating major event days, it is also important for a utility to consider its controllable service quality results.[6] That is, what can a utility impact in terms of reliability, or where is the "juice worth the squeeze?" In times of extreme events, it may be unreasonable or impossible to keep track of customer outages. During and immediately after these events, the sole focus of every person in the utility is restoring electricity service. Little attention is paid to data collection when the lights are out.

The IEEE 1366 calculation of Major Event Days (MEDs) is an industry standard used to evaluate major event days, such as severe weather due to a tornado or hurricane, which can lead to unusually long outages in comparison to the distribution system's typical outage. The 2.5 beta method calculation emerged from a heuristic process designed to seek the relative proportion of MEDs that needs to be removed in order to make a long-term reliability trend visible. The separation of event data allows for long-term trend evaluation as well as assessment of outage data in two frames: crisis and normal.[7]

[6] Joseph H. Eto, et al., Lawrence Berkeley National Laboratory, Tracking the Reliability of the U.S. Electric Power System, 2008
[7] IEEE 1366-2003, B.5.1

Outside of major events, some outages, such as planned outages, give a utility a high degree of data certainty. At the time of an outage, a utility can record planned outages as a part of its statistics or separate planned outage minutes into a different category for analysis. This separate category can help a utility see how much down time is caused by its operations. Reliability indices can be useful for many decision-making processes. Some utilities have suggested that reliability indices should form the basis for review of daily operational effectiveness and decision making. The degree to which your management and operations techniques rely on reliability indices will be impacted by how much confidence you have in the validity of the data you are collecting. Collecting useful data may involve using standardized reporting metrics, such as those used by the APPA eReliability Tracker Software.

Furthermore, it is important to do more than simply track and record outage data. In operations, it is also up to each utility to decide the useful frequency of data evaluation and to set goals that make sense. Many utilities evaluate this information on a monthly basis.

This report attempts to present the survey data in a fashion that will help those utilities wishing to create benchmarks from it. Utilities can use this report's data to help improve their performance. If a utility is looking for one place to start, it would be best to measure its System Average Interruption Duration Index (SAIDI) over the course of the year. This IEEE 1366 metric is both size-independent and the best indicator of system stresses.[8]

OVERALL SURVEY INFORMATION

The data presented in this report are based on APPA's 2018 Distribution System Reliability and Operations Survey. The data reflect activity from January 1, 2017 to December 31, 2017. Any additional data presented are limited to specific reliability indices collected in the previous biennial surveys. Many respondents did not answer all of the survey questions. Many questions were multiple-choice and, in many cases, a utility could select more than one option. In such an instance, the count of total responses to the question can be greater than the number of total survey participants. However, the count of responses to one option within the question cannot be greater than the total number of survey participants. For example, in a question where participants can check all that apply, the total count of responses to the question as a whole can be greater than 161, which is the total number of survey respondents for 2018. Alternatively, if the question only enables the respondent to select one option, the total number of responses to the question cannot be greater than 161.

The adverse part of conducting a survey with voluntary participation is the possibility of reporting bias. Though APPA feels that the participating utilities are reporting the data with honest intentions, there is always the possibility of non-intentional skewing of the overall data set. Beyond reporting bias, there are regional dissimilarities. For instance, extreme weather is a regionalized and localized phenomenon. Areas hit with severe floods or storms will typically report comparatively worse reliability numbers. This will be especially true for utilities that do not exclude major event days. As with opposing reporting biases, the possibility of varied national weather can provide some balance. However, it is important to note that extreme weather events included in a survey with this sample size could influence the overall reliability numbers.

[8] Cheryl A. Warren, Measuring Performance of Electric Power Distribution Systems – IEEE Std. 1366-2003, Feb 13, 2005

Figure 1: Geographical map of APPA Regions

Region 1: Wyoming, Colorado, New Mexico, Utah

Region 2: Indiana, Illinois, Michigan, Ohio, Wisconsin

Region 3: Minnesota, Iowa, Missouri, Kansas, Nebraska, North Dakota, South Dakota

Region 4: Oklahoma, Arkansas, Texas, Louisiana

Region 5: Maryland, Delaware, West Virginia, Virginia, North Carolina, South Carolina, Georgia, Florida, District of Columbia

Region 6: Nevada, Arizona, California

Region 7: Kentucky, Tennessee, Mississippi, Alabama

Region 8: Maine, New Hampshire, Vermont, Connecticut, Rhode Island, Massachusetts, New Jersey, New York, Pennsylvania

Region 9: Montana, Idaho, Washington, Oregon, Alaska

Region 10: Puerto Rico, American Samoa, Guam, Virgin Islands

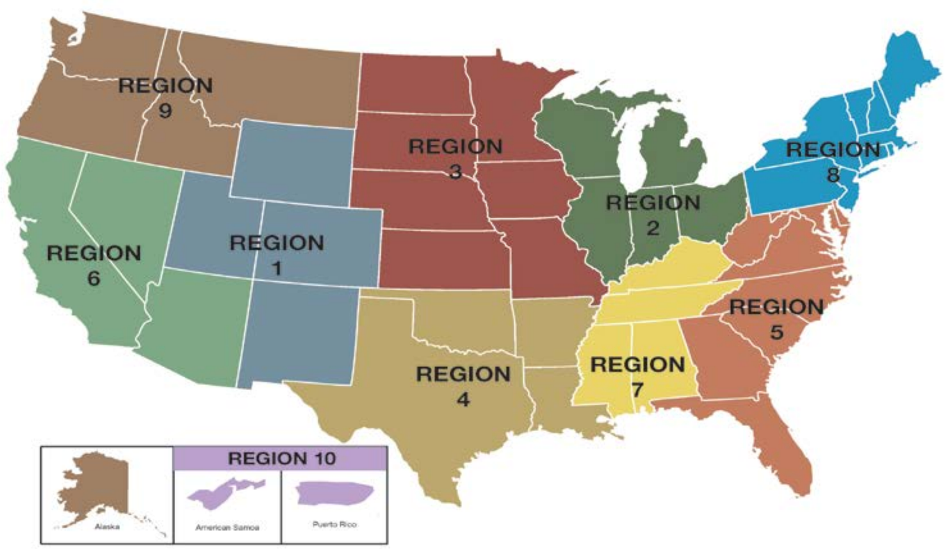
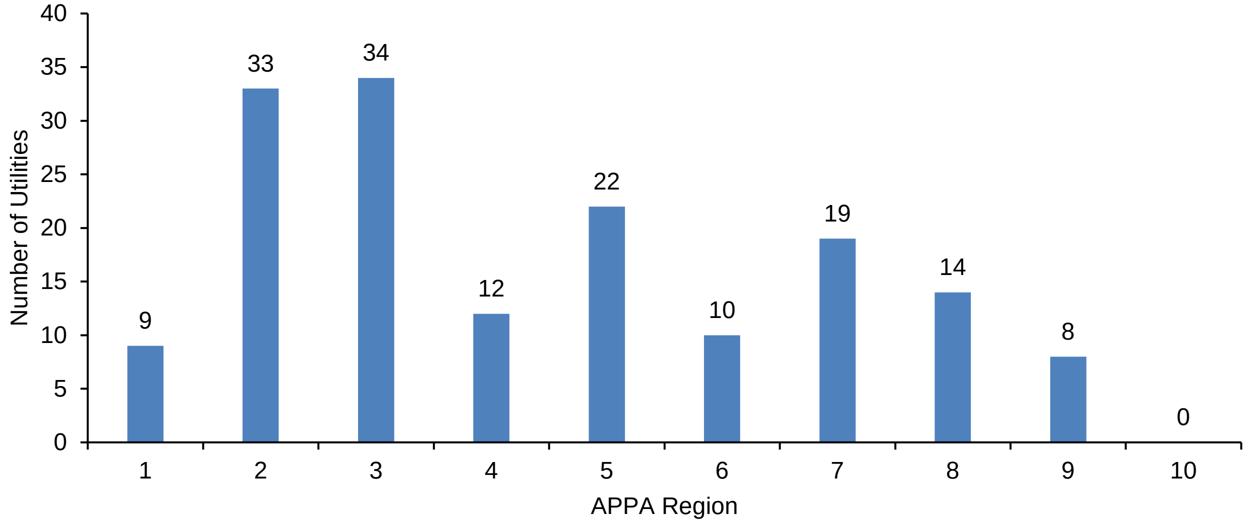
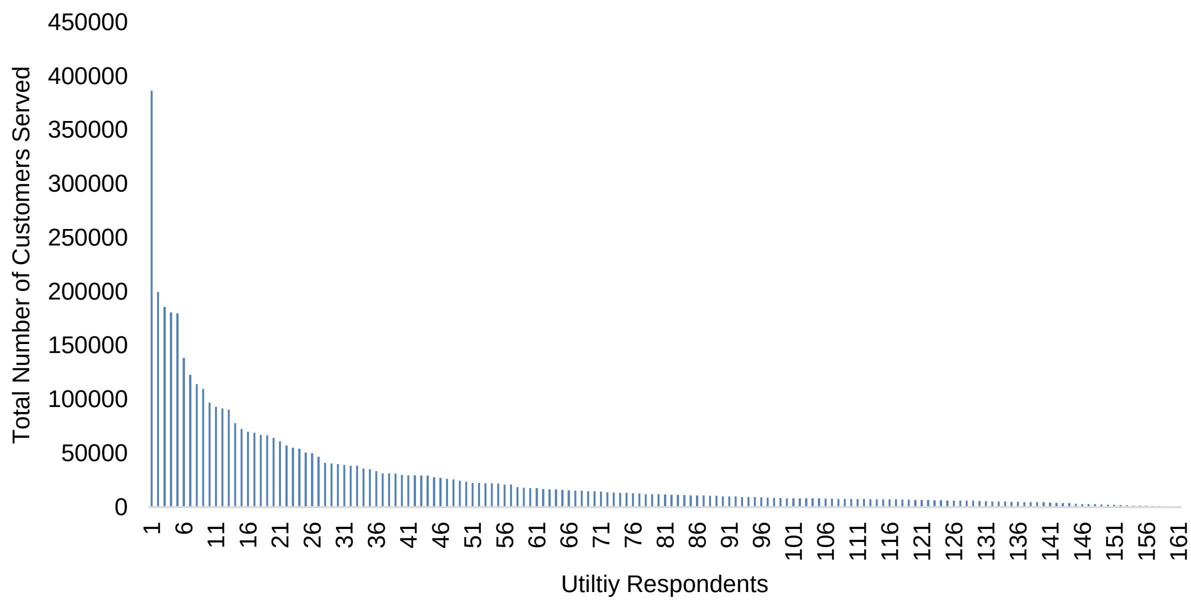


Figure 2: Count of utilities by APPA region



In total, 161 utilities from nine APPA regions participated in the 2018 reliability survey. A graphical visualization of the different APPA regions can be seen in figure 1. As can be seen in figure 2, the highest concentration of participants is from regions two and three.

Figure 3: Utility respondents arranged in order of total number of customers served



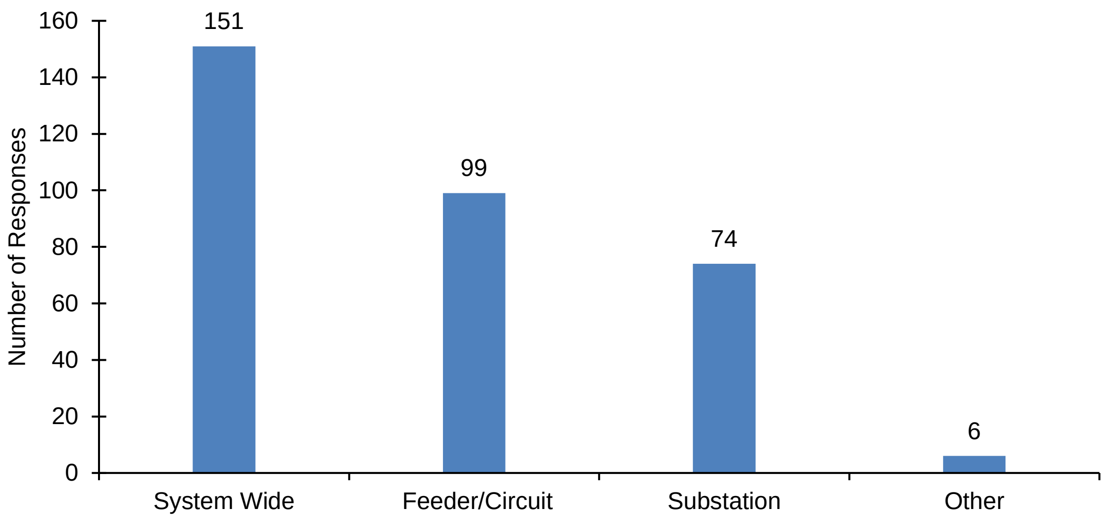
In figure 3, the number of customers for each utility that participated in the survey is shown in order of decreasing customer size.

SECTION I: OUTAGE TRACKING

Equipment failure, extreme weather events, wildlife and vegetation contact are some of the most common causes of electric system outages. Electricity service interruptions are costly for both utilities and communities.[9] Tracking helps utilities understand and reduce outages. Yet, to track outages successfully, a utility must classify them. This section looks at utility outage tracking practices, such as technologies used and tracking/recording approaches.

Like previously discussed, utilities choose differing methods to track outage data. Some prefer to only collect sustained outages, while others will collect both types. In addition to classifying outages based on time, utilities have the decision of where to apply their reliability indices. Most utilities choose to calculate indices on a system wide basis to capture the overall health of the system. Many will decide to dig deeper by calculating indices by feeder/circuit, substation, or some other level in the system. Applying indices at multiple levels allows utilities to have a general outlook as well as hone in on the specific areas of the system that may need more attention than others.

Figure 4: Count of utility respondents applying reliability indices at particular system levels



Participants were asked to indicate the technologies they use to track outages. Within a technology category, such as SCADA, there are different levels of data acquisition systems. As shown in Table 1 many SCADA systems can report only on certain key points, leaving a utility to rely on customer call-ins to report outages.

Table 1: Count of respondents that reported using outage tracking/recording technologies

eReliability Tracker Software	109
SCADA System	93
Paper Records	59
Outage Management System	54

[9] Understanding the Cost of Power Interruptions to U.S. Electricity Consumers, Kristina Hamachi LaCommare and Joseph H. Eto, Lawrence Berkeley National Laboratory, 2003

Spreadsheet	41
Database	41
Smart Grid/Smart Meters/ Automated Metering Infrastructure	30
Other	5

Participants were asked if they calculated major outage events for separate analysis. Respondents were instructed to check all methods for calculating major events that applied at their utilities. The method for excluding major events can have a significant impact on a utility's reliability indices. Therefore, analyzing both indices including and excluding major events allows a utility to see the overall system trends. As shown in Figure 5, methods to remove major events vary significantly among utilities. Some utilities apply "other" methods, such as excluding outages based on severity of weather events.

Figure 5: Count of respondents per method for calculating major events

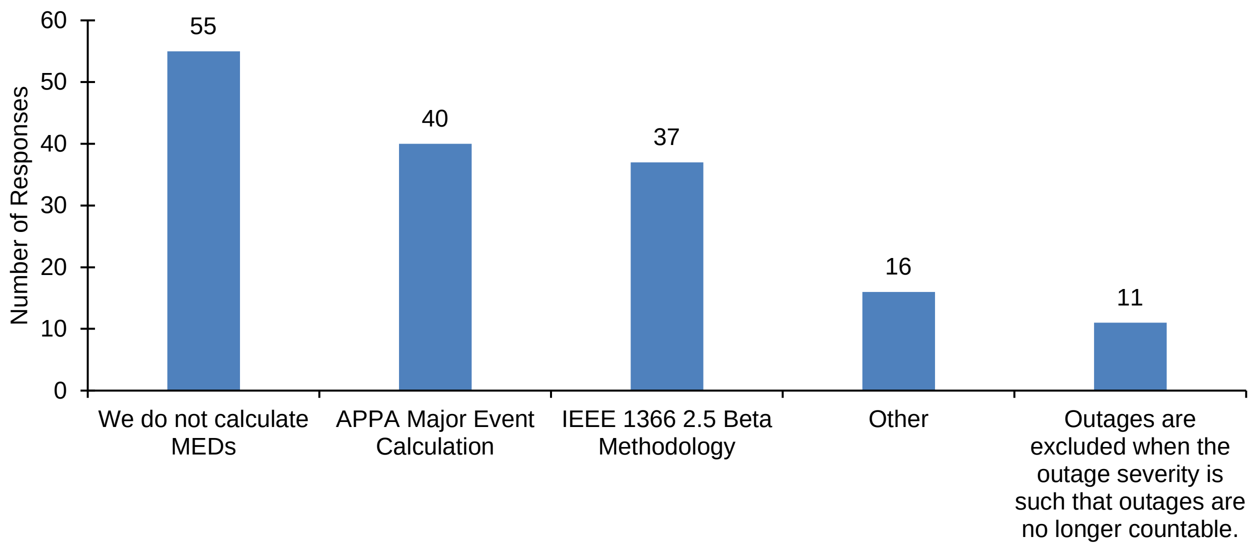


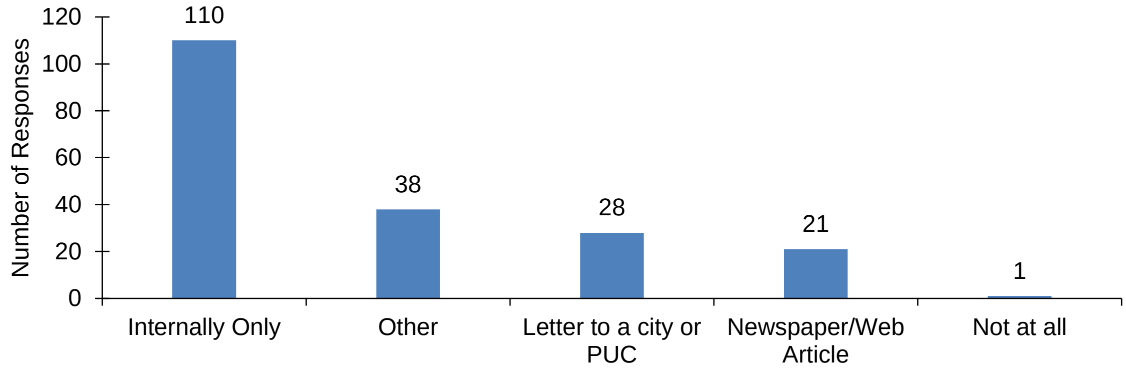
Table 2 shows the way in which utilities treat their planned outages and major event days when calculating reliability statistics.

Table 2: Count of practices used for calculating and reporting reliability indices

	Yes	No
Does your utility generate reliability reports?	151	10
Do you exclude Major Event Days in the analysis?	104	55
Are you required by your state utility commission or public service commission to track/report reliability?	31	127

Calculating reliability statistics alone is not enough to aid in the improvement of your system. To do a proper analysis and gain an understanding of any distribution system, reliability reports should be generated. As can be seen in Figure 6 many utilities choose to share their reports internally, publicly through newspaper outlets and articles, or even share the information with their board or PUC.

Figure 6: Methods used by respondents to share reliability reports



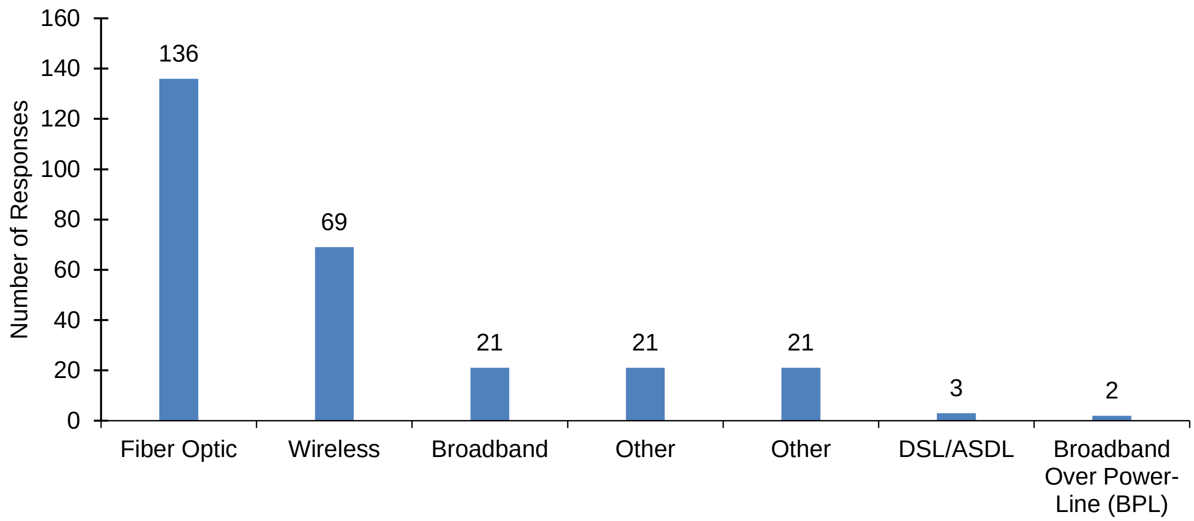
In the following sections, this report makes a distinction between sustained and momentary outages. However, depending on the configuration of a circuit, including breakers, reclosers and sectionalizers, it is possible for customers to experience both momentary and sustained interruptions on the same circuit and during the same outage event. Further, some customers can have power restored before other customers on the same circuit. The ability of a utility to capture this data can cause significant variations in final reliability statistics.

Table 3: Count of responses indicating implementation of an automated switching scheme

	Yes	No
Has your utility implemented an automated switching scheme?	129	33

Due to the growing presence of technology in the industry, it is important for utilities to assess the different available technologies used for retrieving distribution system information. Figure 7 shows which system technologies are used by respondents.

Figure 7: Count of responses indicating communication technologies used for retrieving distribution system information



The survey dove a little deeper for the utilities selecting wireless technologies in order to illustrate which wireless technologies are used for retrieving distribution system information. Table 4 below shows which wireless technologies are used by respondents. Often these wireless technologies are used in combination with the other technologies listed above.

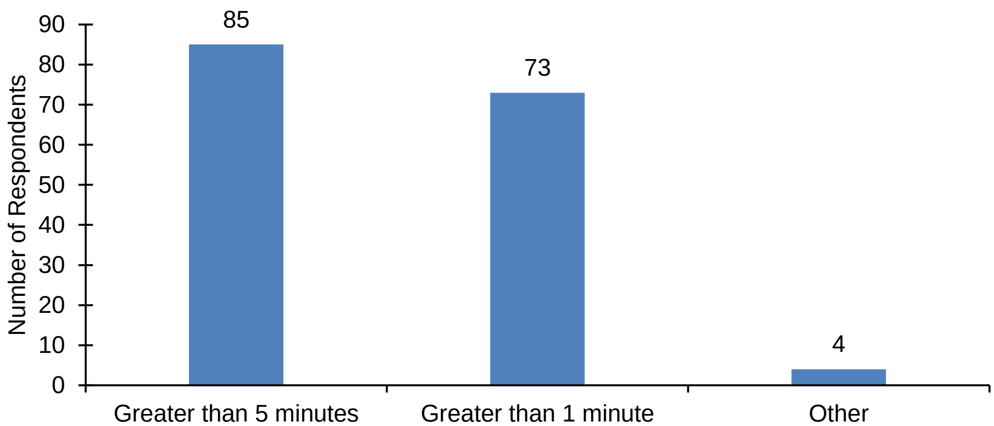
Table 4: Count of utilities using different wireless technologies

Radio-Licensed spectrum	21
Cellular (2G, 3G, 4G, LTE)	11
Mesh (Wi-Fi)	8
Microwave	5

SECTION II: SUSTAINED OUTAGES

Sustained outages are the most commonly tracked outage type. When tracking outages, many utilities exclude scheduled outages, partial power, customer-related problems, and qualifying major events from the reliability indices calculations. While excluding these events in final reported statistics may be appropriate, all data should be reviewed internally for utility-level decision making. In this section, we evaluate participant outage definitions, reliability statistics and common causes of sustained outages.

Figure 8: Count of respondents' definition of a sustained outage



In the survey, utilities were asked for sustained outage reliability statistics collected from January 1, 2017 to December 31, 2017. These metrics take the form of System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI) and Average System Availability Index (ASAI). Definitions for the calculation of these indices appear in Appendix B of this report.

SAIFI is reported in average interruptions per year for all customers connected to the system. SAIDI is reported as the average duration in minutes of the interruptions. CAIDI is reported as the average length of time in minutes that a customer outage lasts. ASAI is the percentage of time that the system was available to deliver power per year.

Table 5 displays the quartiles and averages for the reliability statistics that were reported. Many readers will notice the inconsistency between the SAIDI and SAIFI calculations and the related CAIDI. In mathematical terms, CAIDI is SAIDI divided by SAIFI; however, the data reported do not always show that relationship.

For comparison, similar average statistics from the survey years 2005, 2007, 2009, 2011, 2013, and 2015, which represent data from years 2004, 2006, 2008, 2010, 2012, and 2014, respectively--are included in Table 7. No clear pattern or trend emerges from the analysis of the data sets over the years.

Table 5: Summary statistics of the 2017 reliability data submitted to the 2018 survey

	SAIFI	SAIDI	CAIDI
Minimum	0.03	0.38	0.08
First Quartile	0.36	20.84	42.25
Median Quartile	0.69	42.31	71.33
Third Quartile	1.17	84.86	106.00
Maximum	9.60	487.66	292.33
Average	0.99	60.02	82.40

Table 6: Summary statistics of the 2017 reliability ASAI data submitted to the 2018 survey

	ASAI (%)
Greatest	99.9996
First Quartile	99.9949
Median Quartile	99.9900
Third Quartile	99.9785
Least	98.9580
Average	99.9510

Table 7: Average reliability statistics from previous surveys

Survey Year	SAIFI	SAIDI	CAIDI	ASAI (%)
2005	1.60	54.03	65.91	99.79
2007	4.18	69.8	90.06	99.97
2009	0.88	68.98	86.75	99.90
2011	0.81	46.36	73.86	99.86
2013	1.11	58.49	96.47	99.87
2015	0.91	62.53	78.80	99.91
2018	0.99	60.02	82.40	99.95

Figures 9 – 12 show the average values for SAIFI, SAIDI, CAIDI and ASAI by APPA region. Since not all states had a utility submitting data for the survey, APPA regions were considered the most appropriate scale for display and analysis. For a list of states in each region, see Appendix C.

Figure 9: Average SAIFI by APPA Region

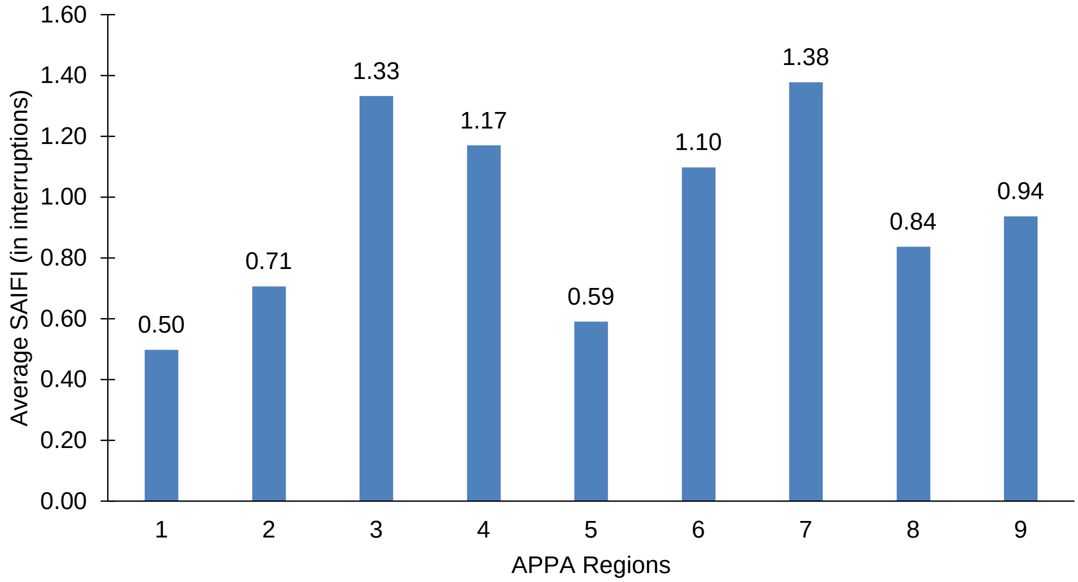


Figure 10: Average SAIDI by APPA Region

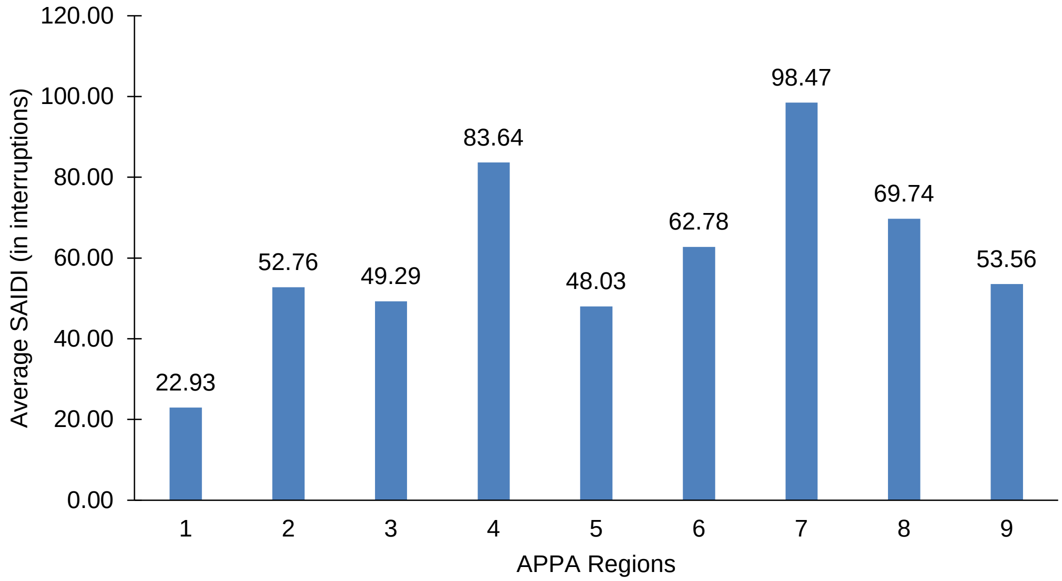


Figure 11: Average CAIDI by APPA Region

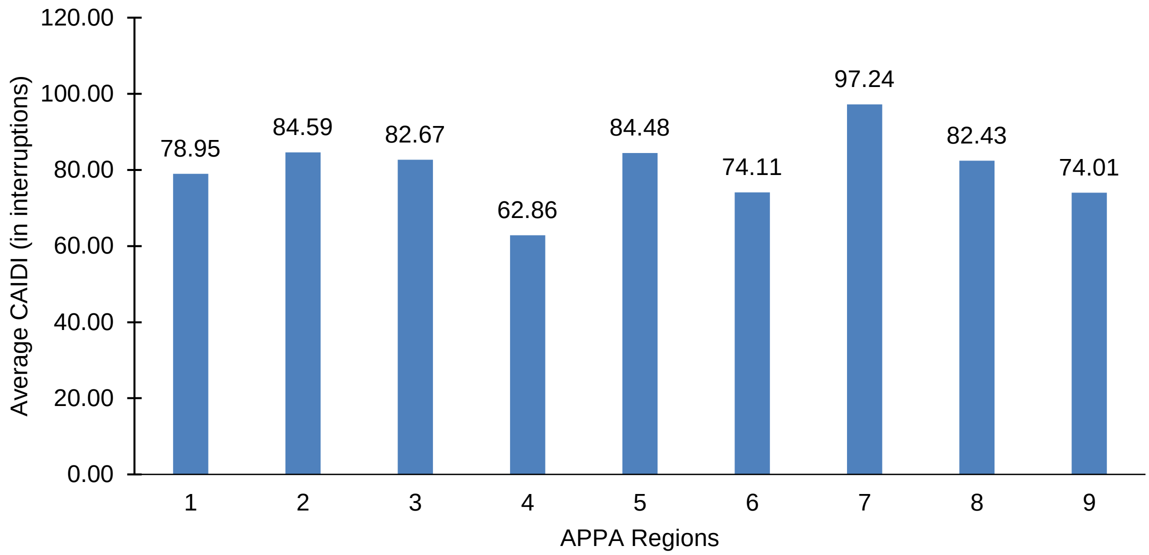
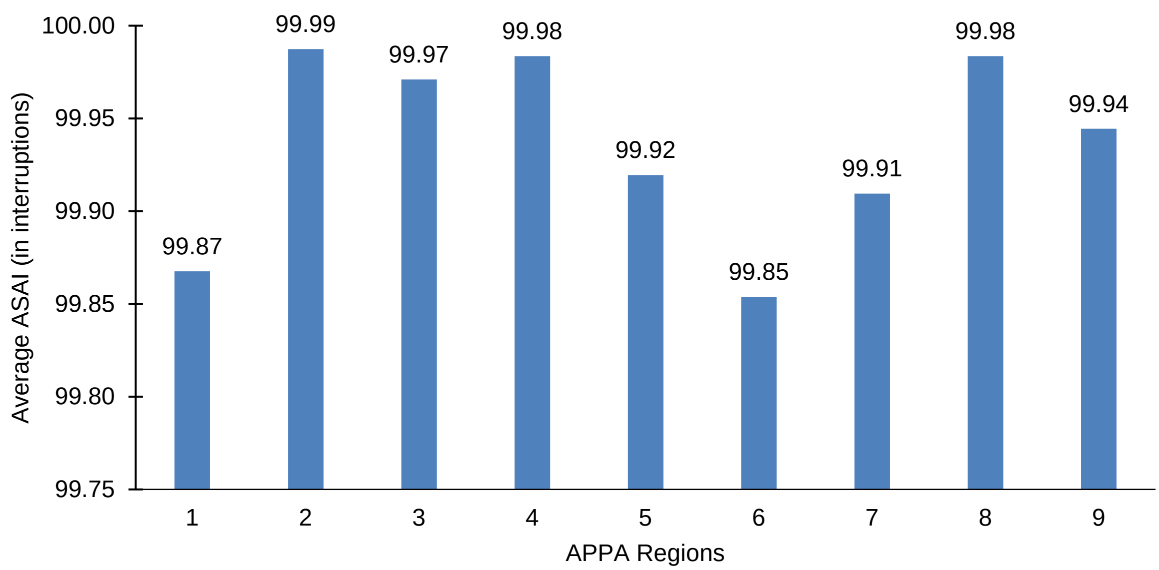
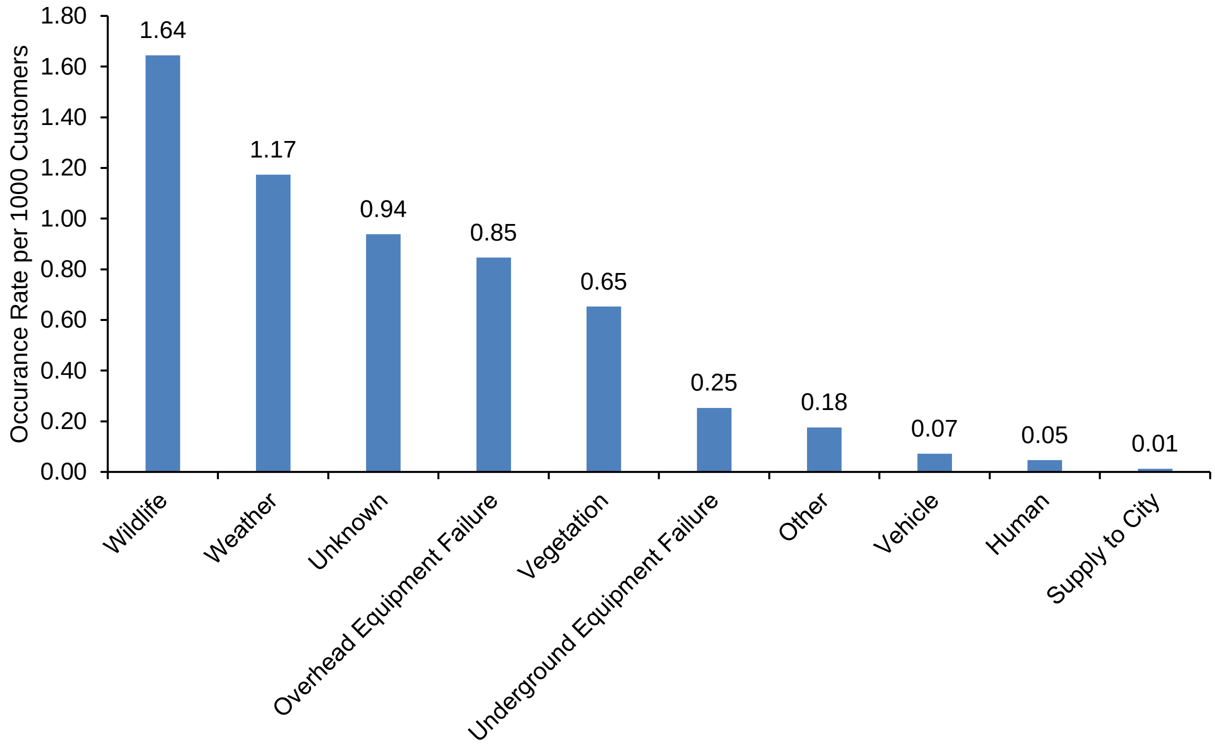


Figure 12: Average ASAI by APPA Region



Outages have many possible causes. The survey asked utilities to supply the number of times per year they experienced outages from various causes. To effectively limit differences in utility size within the analysis of outage causes, the occurrence rates shown in figure 13 are customer-weighted. The data represent the number of occurrences of that cause per group of 1000 customers. For instance, 1 means 1 outage due to that cause per 1000 customers on average. The use of the term “other” covered many types of outage causes not listed in the survey, such as excessive loading and scheduled maintenance.

Figure 13: Average customer-weighted occurrence rates per 1000 customers for common causes of sustained outages



As mentioned, weather is the most common cause among survey respondents. Weather events can include storms, flooding, lightning, wind, and ice. Often during storms, many components will fail at the same time. For example, wind can cause outages by blowing over trees and poles or by stimulating Aeolian vibrations. To combat high wind conditions, utility engineers may increase phase-to-phase spacing and conductor tension to remediate areas where wind caused outages are more frequent. Many utilities design their systems to accommodate a level of disturbance in many outage areas. There are National Electrical Safety Code requirements to help utility staff use the right criteria when designing distribution infrastructure to tolerate high winds and avoid public danger from sagging lines in hot weather, or during temporary overload situations[10].

Figure 13 shows that wildlife is the most common cause of outages. Wildlife-related outages can include many types and species of animals. To reduce the number of outages within this category, many utilities find it important to evaluate the type of animal causing the problem, the time of day in which the outage typically occurs and the manner, in which the animal gets past current preventative measures.

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[10] See: http://standards.ieee.org/about/nesc/

Overhead equipment failure is the fourth most common cause of sustained outages, and underground equipment failure is sixth. The clear implication is that preventative system maintenance programs can be a valuable tool to reduce outages. Similarly, vegetation is the sixth most common cause of outages. This could also indicate the potential benefits of implementing an effective vegetation management plan.

SECTION III: MOMENTARY OUTAGES

For customers, momentary outages can be a hazard to electronic equipment. Since most new electronic equipment cannot tolerate a significant drop in voltage, utility concern with the impact of momentary outages is increasing.[11] Equipment that is sensitive to momentary interruptions has a nearly ubiquitous presence in customer workplaces and households. Though these new sensitive loads usually don't make up a significant portion of the total load served, it is important to be aware of them. Information on momentary outages can be helpful in tracking down problems that may eventually lead to sustained outages and power delivery problems. In this section, we evaluate participant momentary outage definitions, tracking technologies used and common causes of momentary outages. Although capturing and analyzing momentary outages is important, for many utilities it can be difficult. Many small utilities simply may not have the technology to do so.

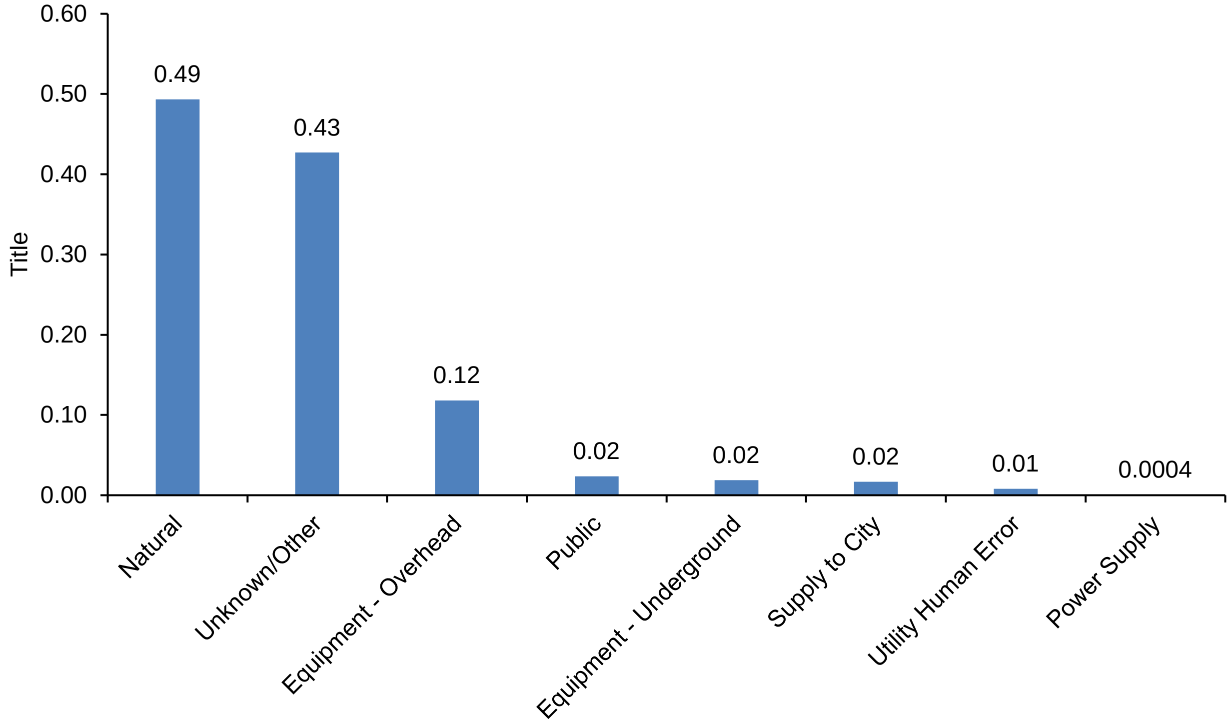
Table 8: Count of respondents using a particular technology to capture momentary outages

Via SCADA system	97
Trip and reclose sequence with no lockout	89
Individual trip and reclose events	69
Customer call-in's	57
Via outage management system	21
Via Smart Grid/Smart Meters/Automated Metering Infrastructure	21
Other	12

Like sustained outages, momentary outages have many possible causes. The survey asked utilities to supply the number of times per year they experienced momentary outages from various causes. To effectively limit differences in utility size within the analysis of outage causes, the occurrence rates shown in Figure 14 are customer-weighted. The data represent the number of occurrences of that cause per group of 1000 customers. For instance, 1 means 1 momentary outage due to that cause per 1000 customers on average. As seen in Figure 14, natural, unknown, and overhead equipment causes are reported as the most significant causes of momentary outages.

[11] LBNL -52048 A New Approach to Power Quality and Electricity Reliability Monitoring, 2003

Figure 14: Average customer-weighted occurrence rates per 1000 customers for common causes of momentary outages



In general, these data reflect the transient, hard-to-catch nature of momentary outages. Though many utilities are tracking them at some level, it is difficult for a utility to attain the tracking resolution required to identify momentary outages and their associated causes in more than a few key areas.

SECTION IV: POWER QUALITY

Though seemingly an overarching term, power quality typically describes the quality of a distribution system's voltage and current in terms of its sinusoidal form, constant amplitude and constant frequency. Accordingly, APPA considers power quality to be an integral part of a utility's service to its customers; however, this report does not address power quality issues on a deep technical level. Rather, this section of the report examines the perceived and factual links between power quality and distribution system reliability.

Many utilities limit the discussion of reliability to outages. However, power quality is a key component of reliability. Many standards address power quality.[12] Moreover, power quality issues vary in scope and addressability. On one hand, a utility can spend significant amounts of money to create a power system with a near-perfect sinusoidal voltage source, regardless of what is happening. On the other hand, a

[12] See IEEE Std. 142, 519, 1159, 1250 and 1346

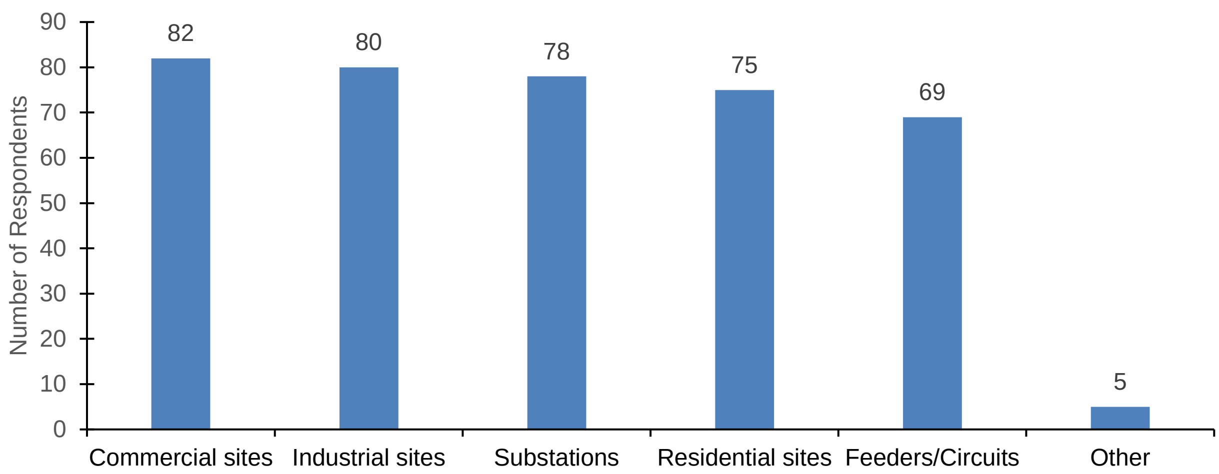
public power utility must pass all of its costs--including power quality control costs--on to the customer. Thus, utilities must find a middle ground that can accommodate customers' power quality needs, allow for addition of unexpected new load without significant impacts, and keep costs at a reasonable level.

As mentioned in the introduction to this report, increasing use of sensitive electronic equipment is creating more loads that respond to distribution system power quality indicators. This problem is compounded by the non-linear nature of many loads. Voltage sag and swell and harmonic currents can be created by distributed generation, load switching or operating many high load devices.

There is a link between the overall power quality a customer experiences and the power usage of other customers nearby. For example, a customer switching on high-wattage motors, arc-welders, or HVAC equipment can create voltage sags for other customers.[13]

For certain customers, power quality monitoring services can be valuable. As shown in Figure 15, the public power utilities perform power quality monitoring at various sites.

Figure 15: Respondents that perform power quality monitoring at each location



In an electric distribution system, customer actions can impact the quality of system operation. For example, the operation of an industrial device that draws a large amount of current with significant cycle variations, such as an arc furnace, can cause rapid fluctuations in local system voltage. The visual effect of these fluctuations is commonly referred to as flicker. As a power quality problem, flicker can be seen visibly in most lighting applications, including incandescent and LED lights, and can be irritating to consumers.

To address flicker problem, some utilities have flicker standards. Without consistent power quality, many customers would be less satisfied. Table 9 depicts respondents concerns with certain voltage-related power quality problems. Utility respondents could select as many problems as are concerns.

[13] Power quality primer By Barry W. Kennedy, 2000

Table 9: Count of utilities concerned with each power quality problem related to voltage

Sag	103
Transient (spike)	63
Swell	54
Flicker	49
Total Harmonic Distortion (THD)	35
Frequency Variation	16
Noise	13
Other	10

Power quality issues can take many forms. A utility may find itself in the position of mediator between a customer causing power quality problems and other nearby customers experiencing the problems. In these cases, it is not unusual for a utility to ask customers to take steps to curb power quality impacts to the electric system. Consequently, exposed customers may be asked to take steps to isolate sensitive equipment. Regardless of the power quality problem, having a policy or requirement to take action to resolve the issue is important.

SECTION V: OUTAGE PREVENTION AND RESTORATION

Many utilities have outage prevention programs as a part of their operations plan. This section looks at utility outage prevention plans and utility participation in mutual aid and disaster planning.

The survey asked utilities to identify the types of outage-prevention programs they have undertaken. Regular inspection, maintenance and outage-prevention programs can provide valuable reliability-related data to support decision making. Among programs identified by respondents, tree-trimming, as a subset of vegetation management, was most frequently selected to help reduce outages. To improve an existing tree-trimming program or to develop an effective tree-trimming programs, it can be helpful to use system reliability statistics to identify areas where maintenance is needed. Evaluating the data will reveal a utility's worst performing circuits for upcoming work.[14]

[14] State of New York Department of Public Service, In the Matter of the Review of Long Island Power Authority's Preparedness and Response to Hurricane Irene, Case 12-E-0283, 2012

Table 10: Count of respondents that have undertaken a given outage prevention program

Vegetation management/Tree trimming	136
Animal/Squirrel guards	136
Routine distribution inspection and maintenance	127
Thermographic circuit inspections	107
Lightning arresters	91
Review of worst performing circuit	87
Converted overhead to underground	81
Covered wire	59
Transformer load management	55
Root cause analysis	31
Circuit rider program	26
Other	13

Trees, while beloved by most customers, are ever-growing hazards for electric lines. When a tree or other vegetation makes a contact with a line, depending on the line's voltage and shielding, a path to ground may be created and an outage can occur. At times, when vegetation crosses two lines, a phase-to-phase fault can occur. When the contact happens, the phase-to-phase fault may not be immediate. The conductive path between two wires can be created over time as the current from the wires drives out a small inner section of the branch making contact between the wires.[15] If a branch crossing between two wires is sufficiently desiccated, a fault can be created through the plant material. There are many ways to trim trees without removing the entire plant. Methods include topping, side trimming, and through trimming.

The downside of a trimming program is that it is a continuous process. In fact, it is important to select a routine that ensures that in between trims, if a storm occurs, branches remain within a proper distance from the lines. With that being said, the utilities were also surveyed on their tree trimming practices or programs. As shown in Figure 16, 41% of the total survey respondents who provide tree trimming programs continuously trim trees. The survey results also showed that approximately 67% of their tree trimming policy or practice is not restricted to their local regulations. These results reflect public power's proactive engagement in tree trimming practices to effectively prevent outages caused by trees. Figure 17 shows the distribution of total annual tree-trimming cost ($) to the utilities, and most utilities spend less than 2 million dollars on tree-trimming programs/practices per year.

[15] Electric Power Distribution Reliability, Richard E. Brown, 2009

Figure 16: Frequency distribution of tree-trimming practices

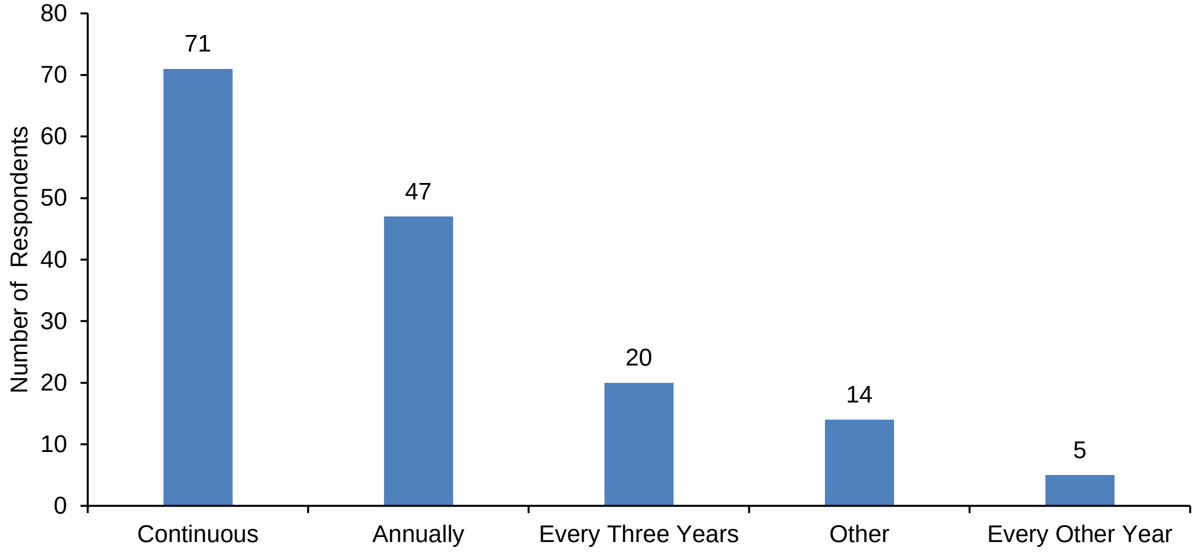
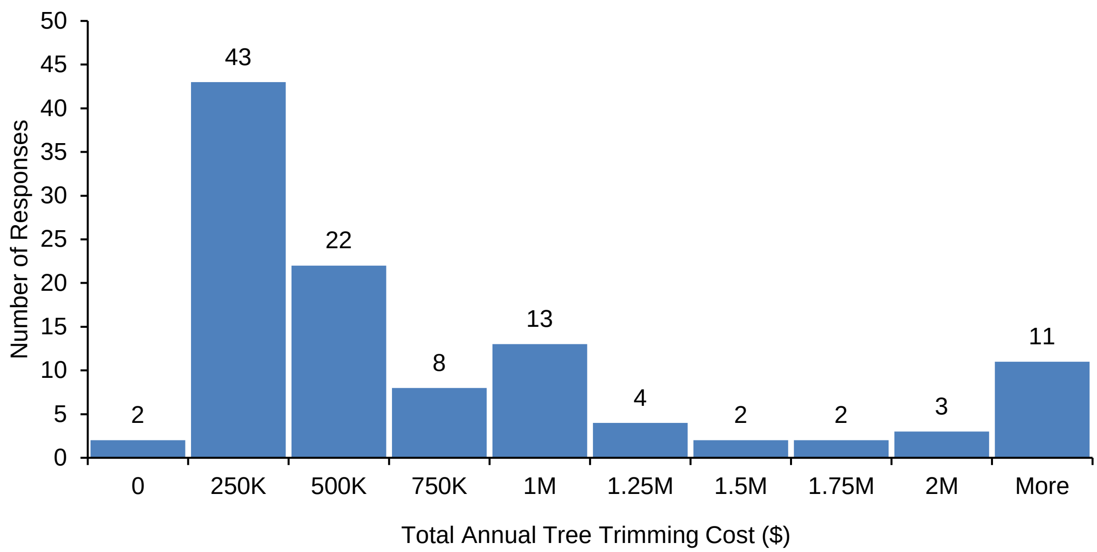


Figure 17: Distribution of total annual tree trimming cost ($)



Other popular outage prevention programs are animal guards and lightning arrestors. Shield wires and lightning arrestors provide protection for circuits that are susceptible to lightning strikes. In many regions, wildlife-related outages are due to squirrels. Since a utility pole is similar to a tree, squirrels frequently climb poles. The heat emitted by electric lines can attract a squirrel, particularly during cold weather. Nearly all squirrel activities that cause outages on distribution transformers can be mitigated using squirrel guards.

Outside of regular outage management plans comes the management of major events and catastrophes. Approximately 90% of the total survey respondents have major storm, event, or disaster plan, and of these plans, 95% are written or documented.

SECTION VI: WORK FORCE ISSUES

A work force that can maintain the distribution system is an essential part of any utility's operations. Of that work force, lineworkers are the primary staff charged with the maintenance and upkeep of the distribution system. This section looks at methods to providing crew coverage, employee practices and different rates of lineworkers employed.

Since there is 24-hour demand for electricity, it is important that a utility find a way to make lineworkers available at all times to solve delivery problems. In the survey, participants were asked how their utility provided 24-hour crew coverage.

Figure 18: Method for providing 24-hour crew coverage

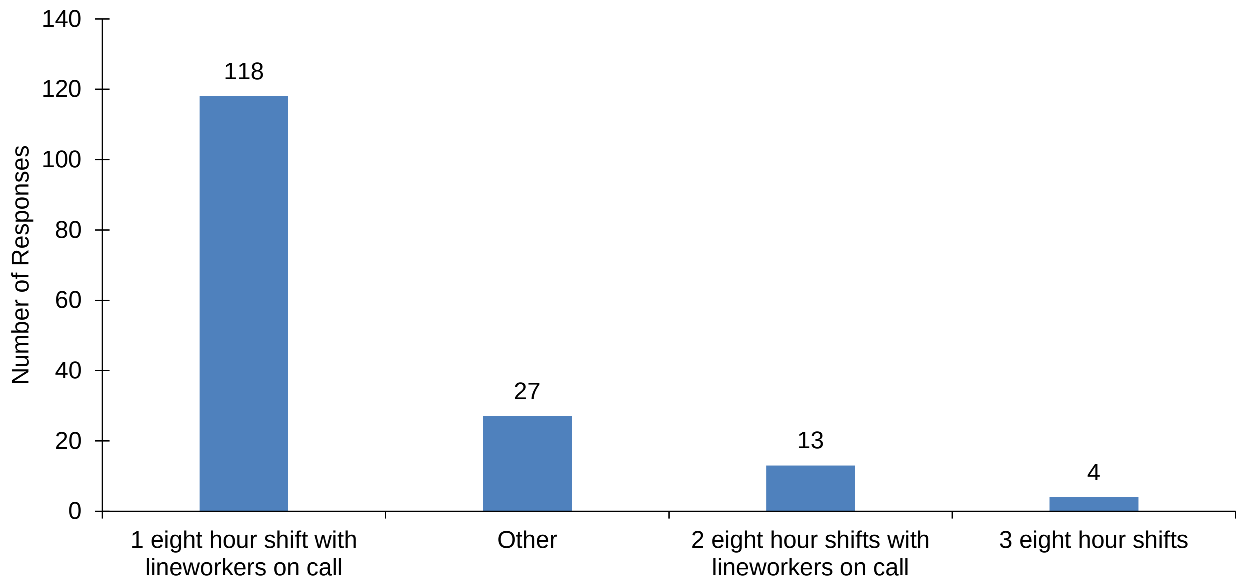
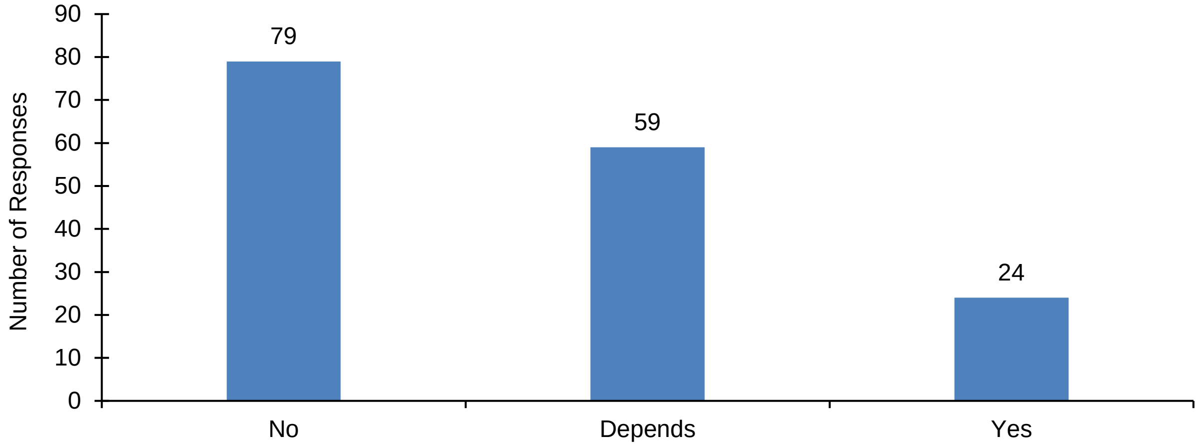
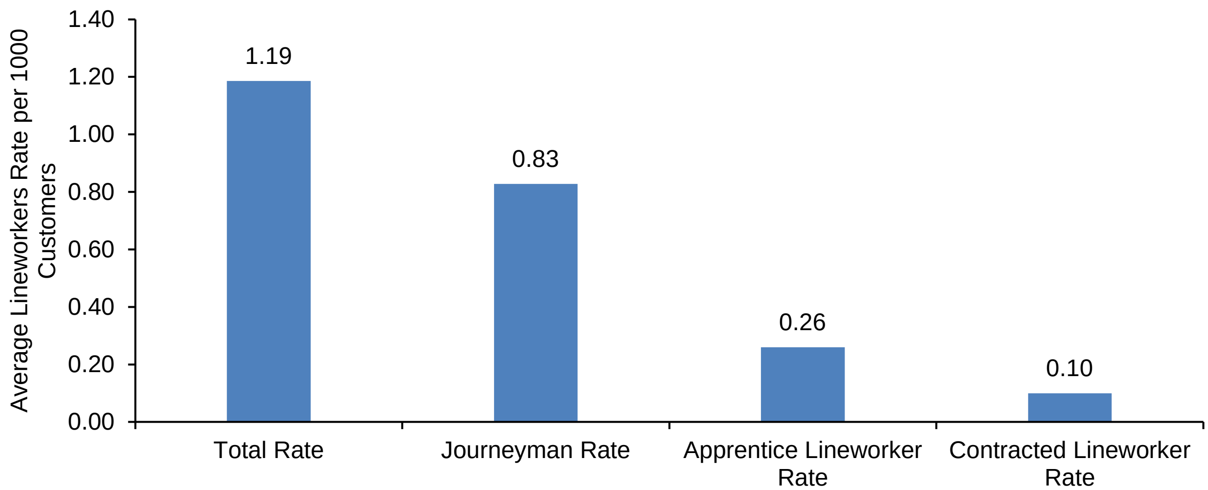


Figure 19: Count of respondents that allow employees to take vehicles home



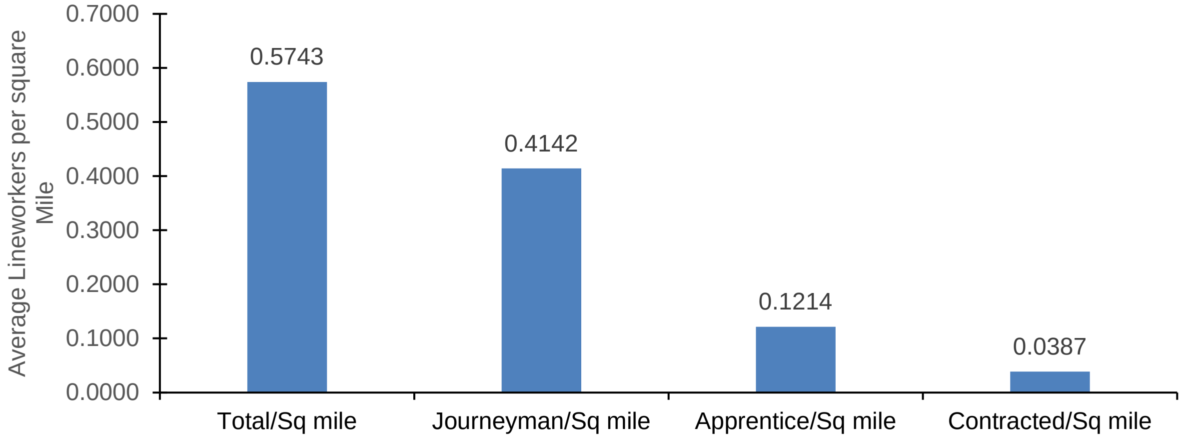
In the survey, the average number of crews that each utility employs was broken down into the categories of apprentice, journeyman, mixed and contract. There was significant variety in the number of lineworkers each utility employs. Figure 20 shows the average customer-weighted rate for employing the three different categories or lineworkers. Similar to the outage occurrence rates shown in the sustained and momentary outage sections of this report, the rates in Figure 20 are customer-weighted rates created to limit differences in utility size in this analysis. The rates represent the number of lineworkers of that category per 1000 customers. For example, 1 in the journeyman column means that on average 1 journeyman is employed at the utility per 1000 customers.

Figure 20: Average customer-weighted rates for employing types of lineworkers



Interestingly, the data showed a wide range of lineworkers per square mile. This range might be useful for a utility in determining the number of lineworkers a utility should employ. Since each utility is different both in condition and circumstance, significant deviation from this range does not necessarily warrant concern.

Figure 21: Average rate of lineworkers per square mile



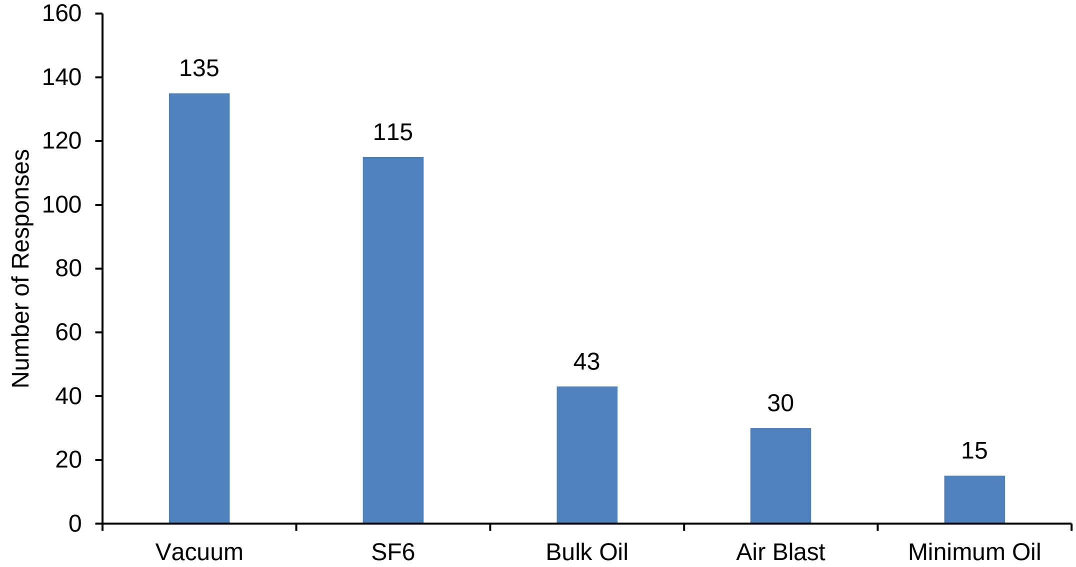
SECTION VII: SYSTEM OPERATION

In a typical distribution system, the substation is the delivery point for power. As a result, maintaining and operating the substation transformers is important to the reliability of the power system. Every time a transformer is overloaded, its useful life is decreased. Typically, this happens through the long-term degradation of the insulating medium.[16] This section looks at specific system characteristics, such as types of materials used, transformer maintenance practices, and fault indication methods.

As the utility personnel knows, substations are important nodes in the electrical system. As central nodes, substations are of high concern to the overall reliability of the electric system. To protect transformers and ensure a problem on one circuit does not transfer to the transformer and other circuits, circuit breakers are used. The circuit breaker is typically the last line of protection between a circuit and a transformer. It can be designed and built as part of a transformer protection scheme at many levels of technological complexity.

[16] Investigations of Temperature Effects on the Dielectric Response Measurements of Transformer Oil-Paper Insulation System, IEEE Transactions on Power Delivery, VOL 23, NO. 1, 2008

Figure 22: Types of breakers used in utility substations



The survey asked participants about their transformer maintenance practices. Table 11 shows the breakdown of questions and responses from the survey on maintaining and testing transformers.

Table 11: Transformer maintenance, testing, and buying practices

	Yes	No
Do you have transformer overload guides?	108	54
Do you have an established transformer maintenance program?	112	49
Do you test transformer oil?	157	3
Does your utility calculate A and B factors for transformers?	51	104
If yes, does your utility use the A and B factors as part of the transformer buying process?	48	3
Does your utility use amorphous core transformers?	39	114

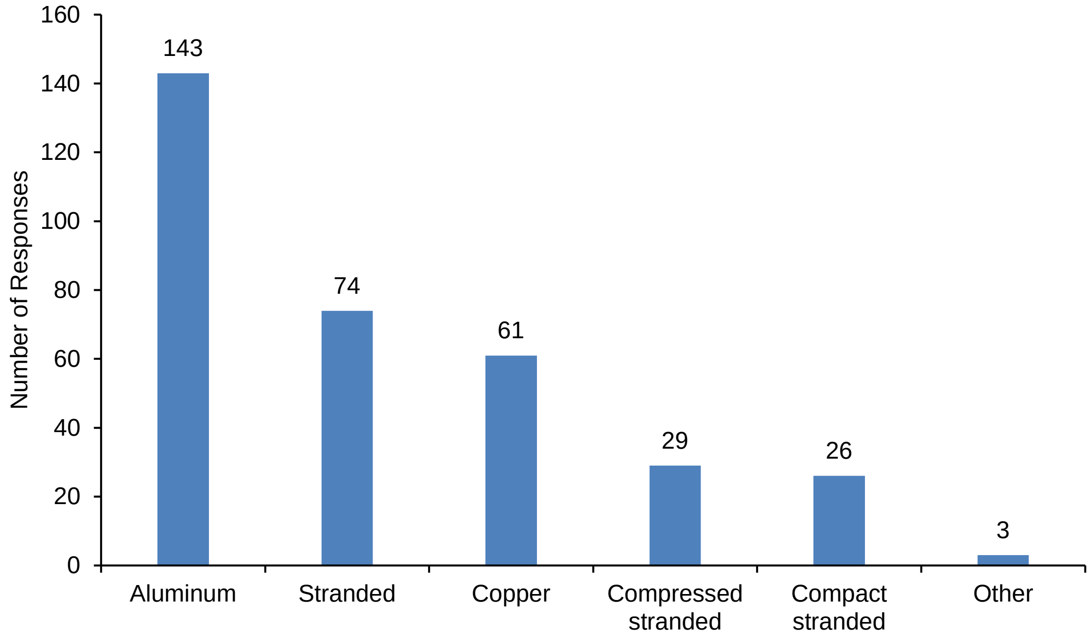
Table 12 contains average customer-weighted rates for distribution system components for every 1000 customers served. These rates are customer-weighted to limit differences in utility size. For example, a “1” in the row indicating rate of distribution substations in operation means the average or median rate is for a utility to have 1 distribution substation in operation for every 1000 customers.

Table 12: Average, median, and standard deviation of customer-weighted rates per 1000 customers for distribution system components and characteristics

	Average	Median	Standard Deviation
Rate of distribution substations currently in operation	0.58	0.41	0.57
Rate of total distribution substation transformers currently in operation	0.87	0.64	0.84
Rate of total substation transformer capacity in MVA (Oil Air)	11.32	10.12	7.90
Rate of total installed distribution (field) transformer capacity (MVA)	11.83	12.26	10.99

Figure 23 shows the various types of material composition used by respondents. Aluminum is the material most commonly used for primary feeder cables.

Figure 23: Types of material composition for primary feeder cables



The survey also asked utilities about the voltages they operate on their distribution system. Voltage data were collected to help utilities understand the decisions other utilities are making about distribution system voltage.

Table 13: Count of respondents operating at voltages overhead and underground

Voltage	Overhead	Underground
4160Y/2400	40	37
6900	9	9
8320Y/4800	9	9
12000Y/6930	13	13
12470Y/7200	94	93
13200Y/7620	29	30
13800Y/7970	32	32
20780Y/12000	11	11
22860Y/13200	12	12
23000	20	8
24940Y/14400	21	20
34500Y/19920	17	12
Other	18	11

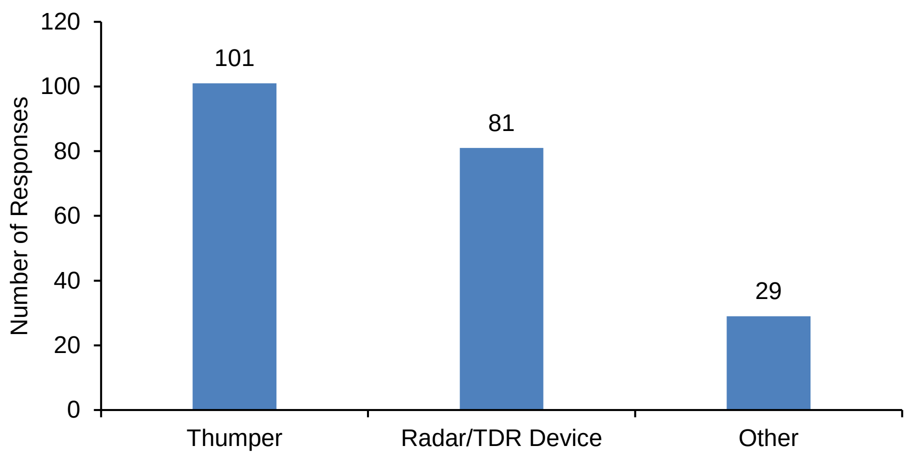
To protect lines, equipment and customers against damage from electrical faults, utilities employ fuses, reclosers, switches, sectionalizers, relays, and circuit breakers. Depending on its settings, a relay is commonly the first element to react to some type of electrical abnormality in a distribution line. Relays are the “brain” of the protection system for distribution components. Relays are often located in substations to monitor and take action upon the detection of various power conditions on feeder lines. Due to the emergence of cost-effective and reliable monitoring electronics, power quality-based distribution protection functions are being integrated into many protection devices.[17] Accordingly, many relays have their reaction to power conditions “timed” to save or blow fuses. Fuse forcing generally implies that fuses are set to blow prior to switch or breaker operation. This is consistent with many larger utility sectionalization guides.

Table 14: Count of respondents practicing a distribution system fuse philosophy

Fuse Force (i.e. fuse blown prior to breaker operation)	111
Fuse Save (i.e. instantaneous trip first, then blow fuse)	51

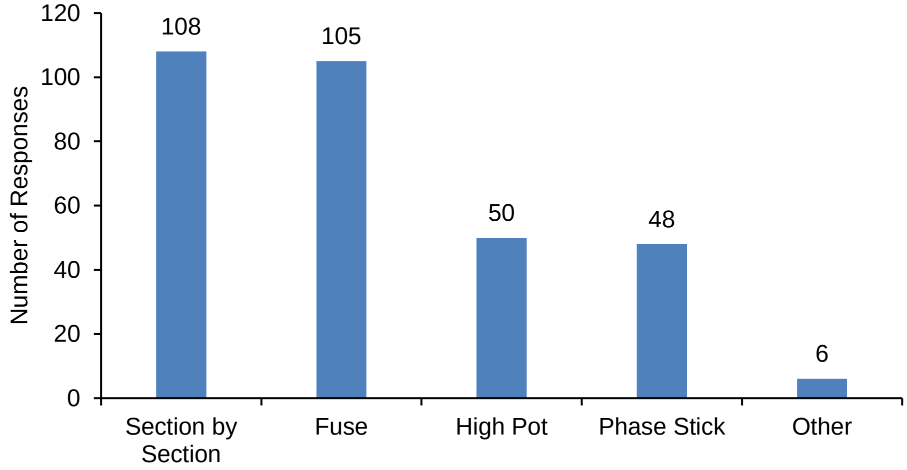
Figure 24 shows that a thumper is the most popular method to locate faults. To sectionalize faulted sections the majority of utilities use a section by section method as shown in Figure 25.

Figure 24: Count of respondents per method to locate faults



[17] Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems, Schweitzer Engineering, 2010

Figure 25: Count of respondents per method to sectionalize faulted sections of cable



Fault indicators are used in electric distribution networks to identify and, in some cases, signal or communicate faulted circuits. Both overhead and underground fault indicators are commonly used. Figure 26 shows the number of respondents using fault indicators on their overhead system, underground system, or both. Figure 27 further breaks down the data to display the common types of fault signals used.

Figure 26: Count of respondents using fault indicators on electrical systems that are overhead, underground, or both

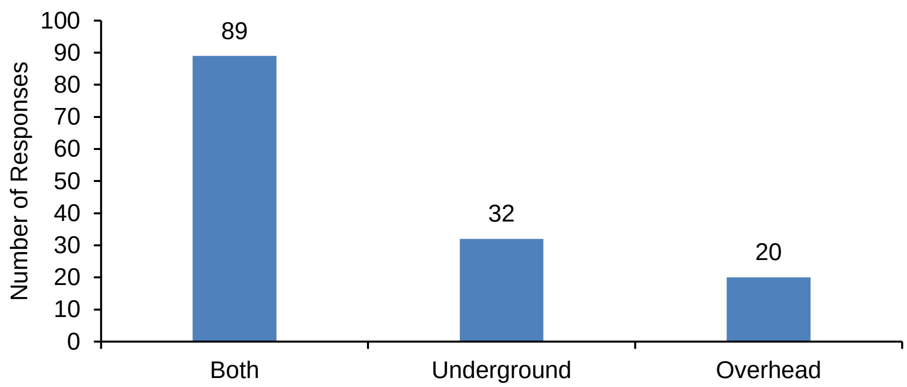
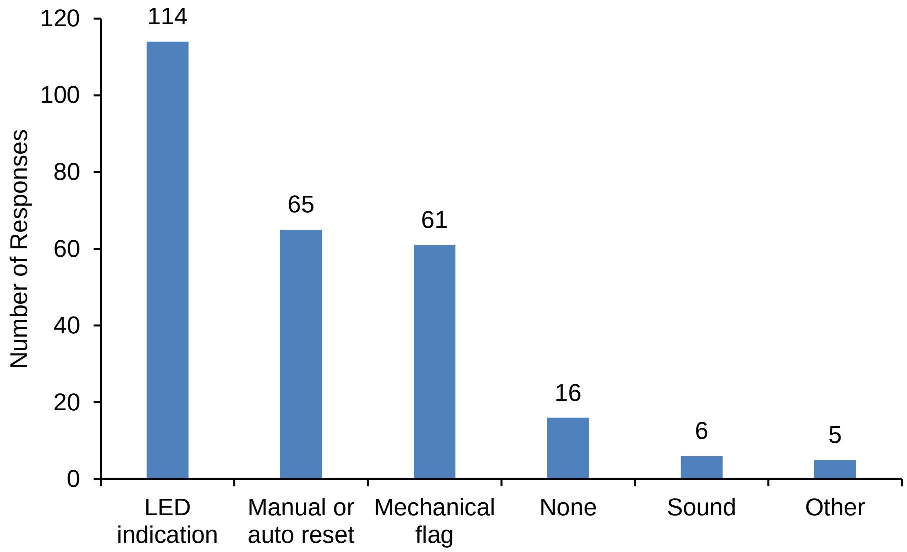
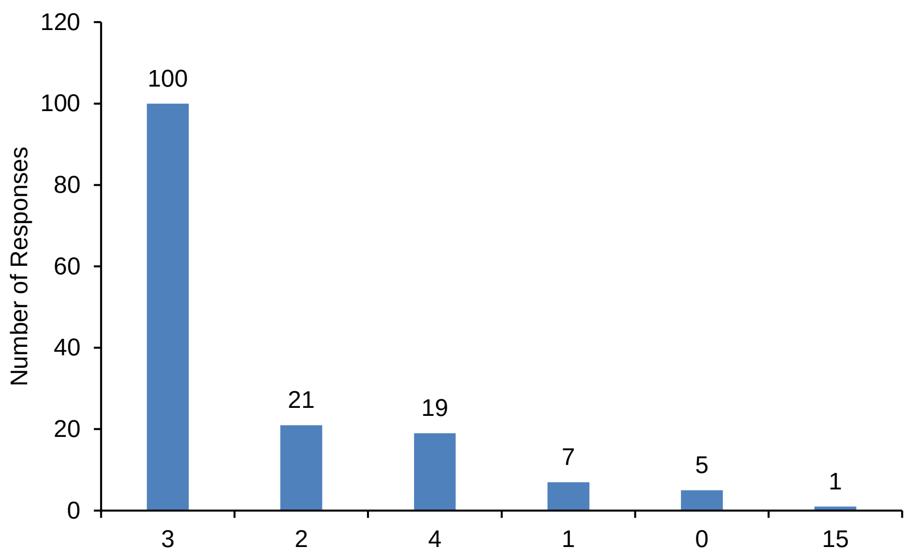


Figure 27: Count of respondents using certain fault signals to indicate electrical faults



The analysis presented in Figure 28 suggests that it is most common to allow three relay recloses before lockout. This assumes that respondents have automatic reclosers, though respondents were not asked directly in the survey. This particular strategy may provide more closing cycles to clear a fault or allow other switching devices on feeder lines to operate. The downside of this strategy would be the repeated short-term interruption of any customers with sensitive power quality needs on a particular line.

Figure 28: Number of relay recloses to lockout



As is shown in Table 15, after the first close, many utilities choose to increase the amount of time a relay stays open. Relay practice widely varies between utilities; however, the close time for a relay after it has been open is often based on the time-current curve used by the utility. Some utilities have a close timing specification set differently from the time-current curve. Figure 29 and Figure 30 illustrate the frequency of responses for the average duration prior to recloses. Both graphs show that most utilities answered around ten seconds prior to the second reclose.

Table 15: Average duration prior to reclose (in seconds)

	Commercial /Industrial Feeder/Circuit	Residential Feeder/Circuit
1st	3.00	3.15
2nd	10.53	10.30
3rd	20.16	20.14
4th	24.82	24.11

Figure 29: Commercial/Industrial Feeder/Circuit average duration prior to reclose (in seconds)

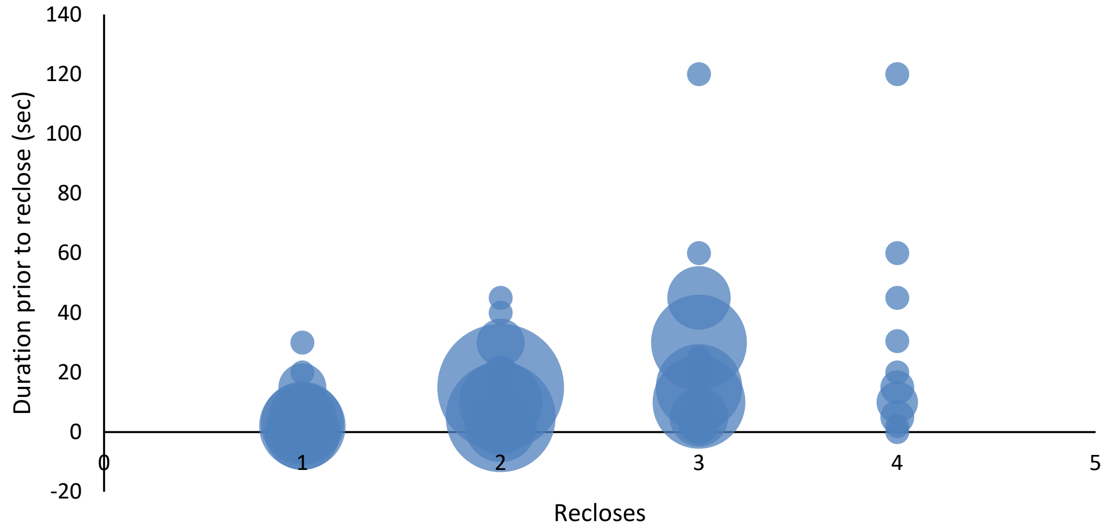
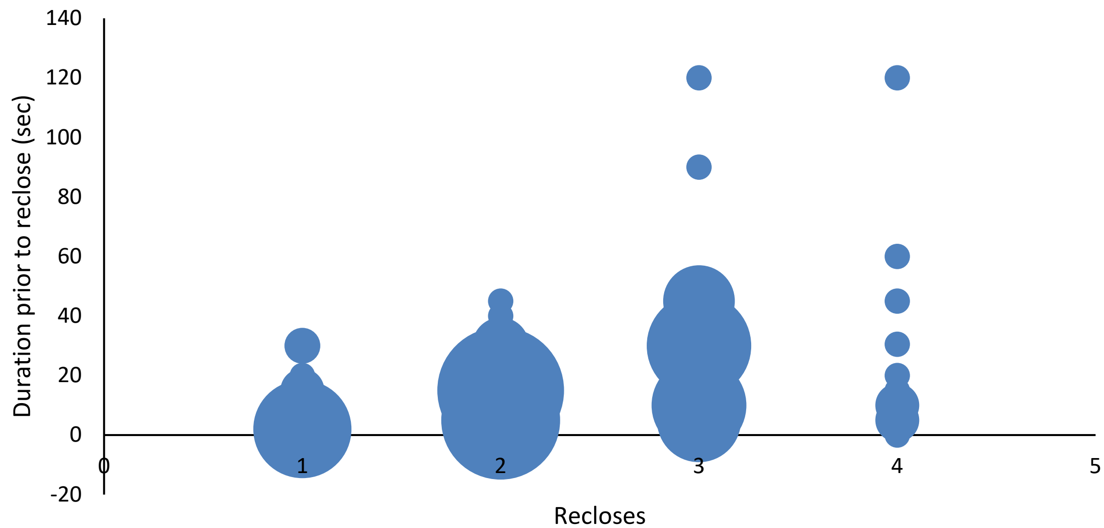


Figure 30: Residential Feeder/Circuit average duration prior to reclose (in seconds)



SECTION VIII: CONSTRUCTION DESIGN

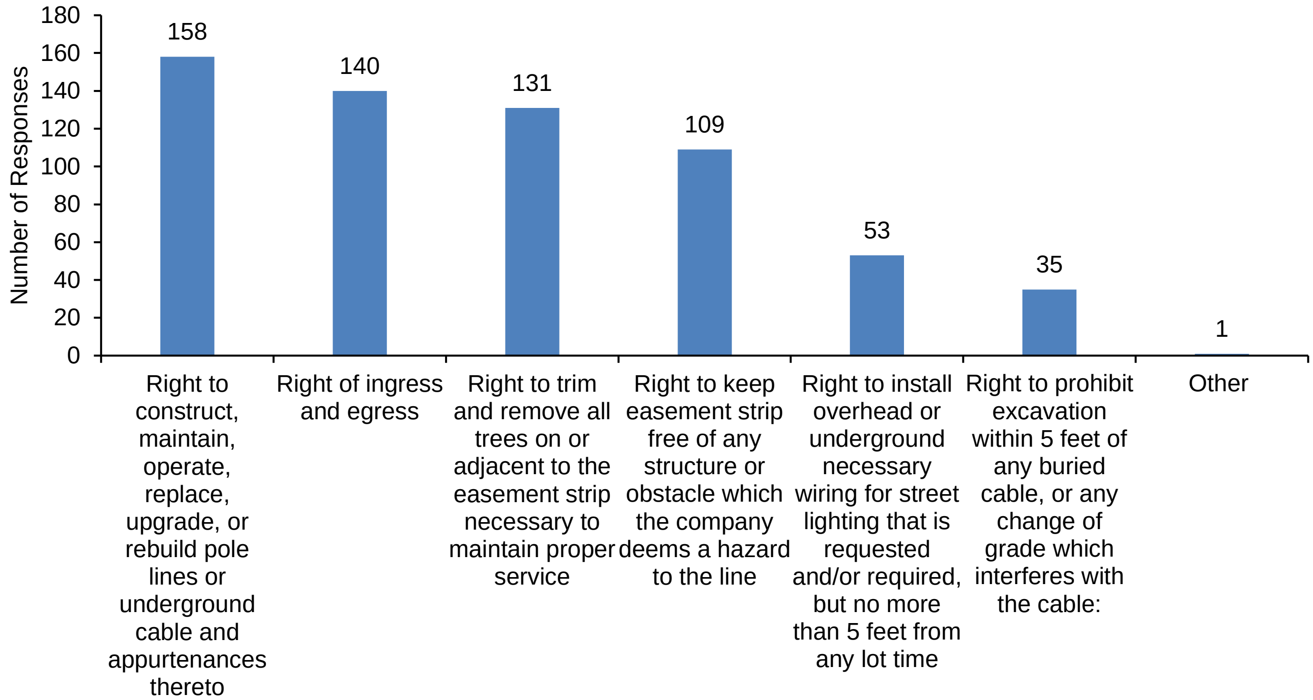
This section of the survey was intended to help illustrate how utilities handle easements and codes and serve new construction.

As shown in Figure 31, every utility surveyed had at least the right to construct, maintain, operate, replace, upgrade, or rebuild pole lines or underground cable and appurtenances thereto. However, asking about utility easements, or property rights can help utility managers see the different means that utilities are using to construct, maintain and operate a given section of utility line. The ideal is that a utility has considered all of these provisions in its easement terms for inclusion.

The rights surveyed were as follows:

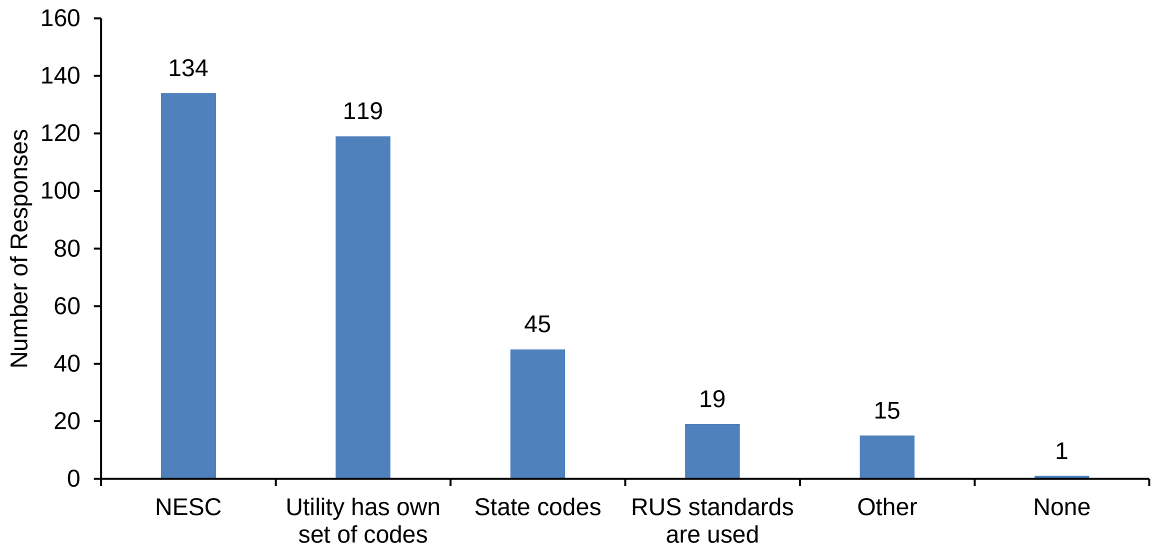
- Right to construct, maintain, operate, replace, upgrade, or rebuild pole lines or underground cable and appurtenances thereto
- Right of ingress and egress
- Right to trim and remove all trees on or adjacent to the easement strip necessary to maintain proper service
- Right to keep easement strip free of any structure or obstacle which the company deems a hazard to the line
- Right to prohibit excavation within 5 feet of any buried cable, or any change of grade which interferes with the cable
- Right to install overhead or underground necessary wiring for street lighting that is requested and/or required, but no more than 5 feet from any lot time

Figure 31: Count of terms included in utility easements or property rights



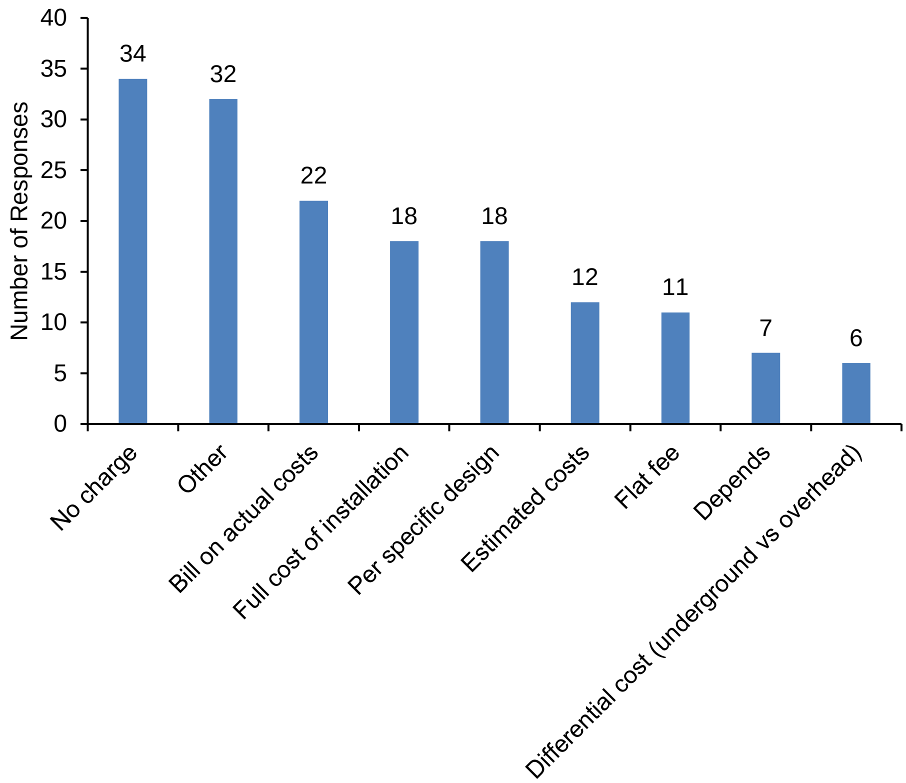
Many utilities use standard codes to guide their construction processes. As can be seen in Figure 32, an in-house code for construction and installation practices is the most common, though many utilities also commonly use the NESC.

Figure 32: Count of utility codes/standards used for construction and installation practices



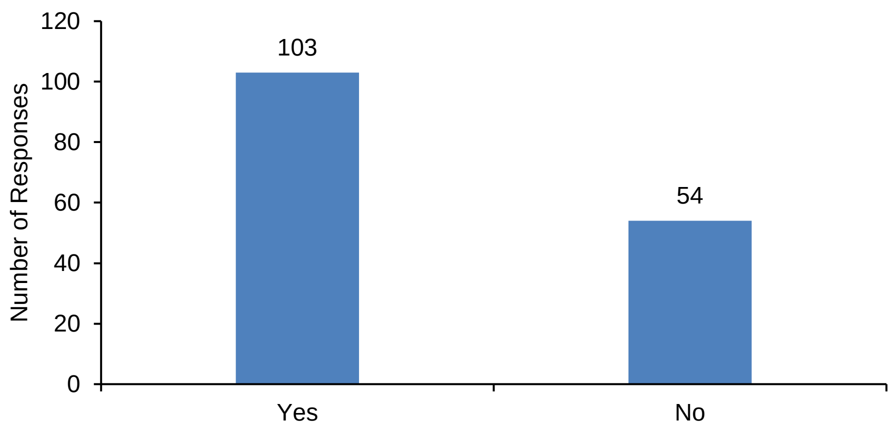
Many utilities charge differently for new construction services for underground subdivisions (excluding house services). Figure 33 illustrates the different methods utilities use to recover the cost of new underground subdivision service.

Figure 33: Count of Charge Practice for New Construction Services to Underground Subdivisions



The survey also asked whether a utility charged to convert an existing service from overhead to underground. As can be seen in Figure 34, the answer was more often than not, yes.

Figure 34: Count of utilities that charge to convert from overhead to underground



Utilities were also surveyed on their new service lateral construction practices. Based on the results, the survey showed that on average, new house service lateral (low voltage to residence) as 89.85% Installed and owned by the utility with 31.15% installed and owned by the customer and 32.23% Installed by the customer and owned by the utility.

The figure below shows whether a utility allows cable/telephone in the house service trench. Figure 36 shows whether the utilities that did allow cable/telephone in the house service trench charged for the service.

Figure 35: Count of utilities that allow cable/telephone in the house service trench

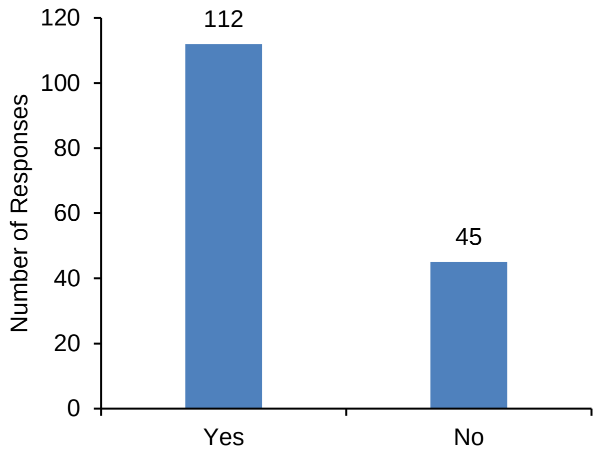
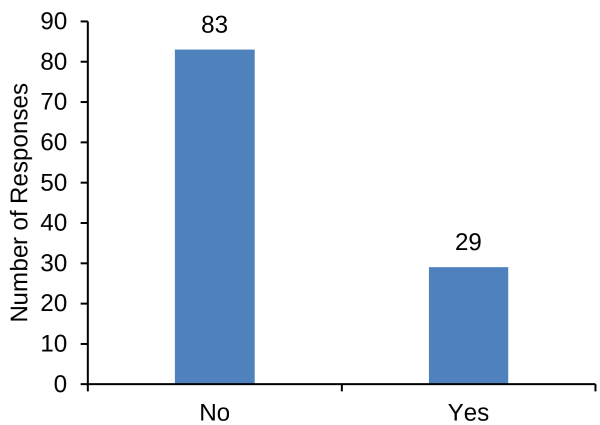
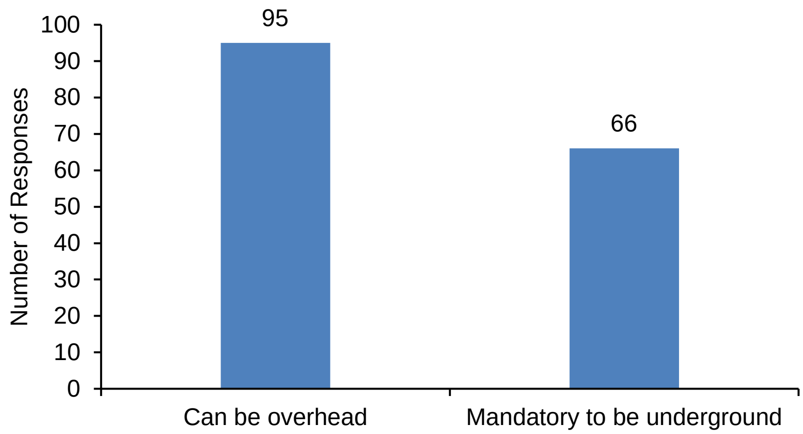


Figure 36: Count of utilities that charge for allowing cable/telephone in the house service trench



Many utilities want to know about mandatory overhead programs. As Figure 37 shows, most utilities said that new construction can overhead.

Figure 37: Count of utilities new construction overhead underground conversion policy



Some utilities consider converting existing overhead lines to underground as they build or renovate lines. Some utilities also perform the work to install sub grade facilities using utility employees. Table 16 illustrates how utilities work with contractors, and which entity terminates the sub-grade facility.

Table 16: Count of utilities working with contractors on sub-grade facilities

Does your utility contract with contractors to install sub-grade facilities?	
Yes	*37*
Sometimes	*37*
No	*36*
If yes, who terminates the contract?	
Utility	*71*
Contractor	*11*
If a contractor terminates, does your utility approve the quality of the workmanship?	
Yes	*39*
No	*4*

Some utilities also allow developers to install facilities of a particular type. A utility might allow a developer to install conduit, or ground sleeves, or an underground system in its entirety. Figure 38 illustrates whether utilities allow developers to perform work and Figure 39 illustrates what kind of facilities the developer is allowed to install.

Figure 38: Count of utilities that allow developers to install facilities

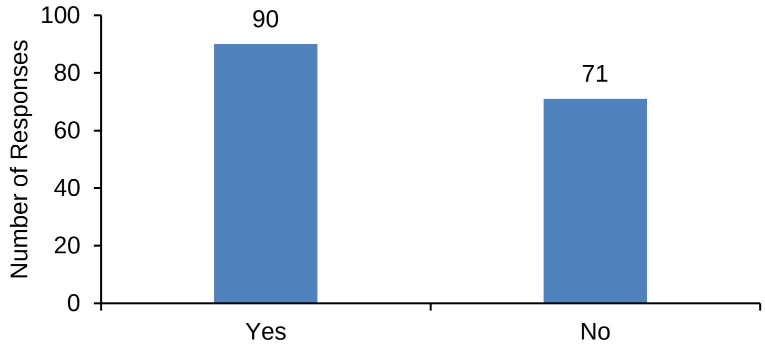
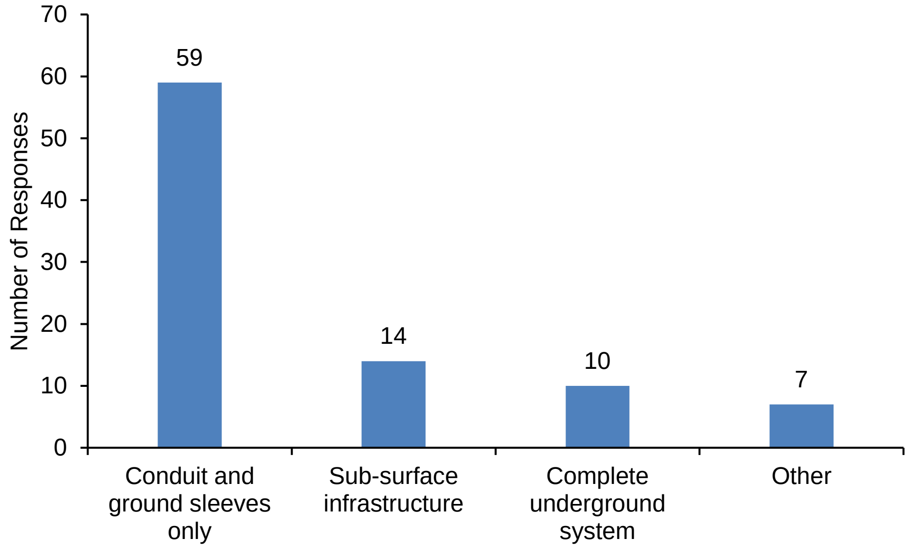
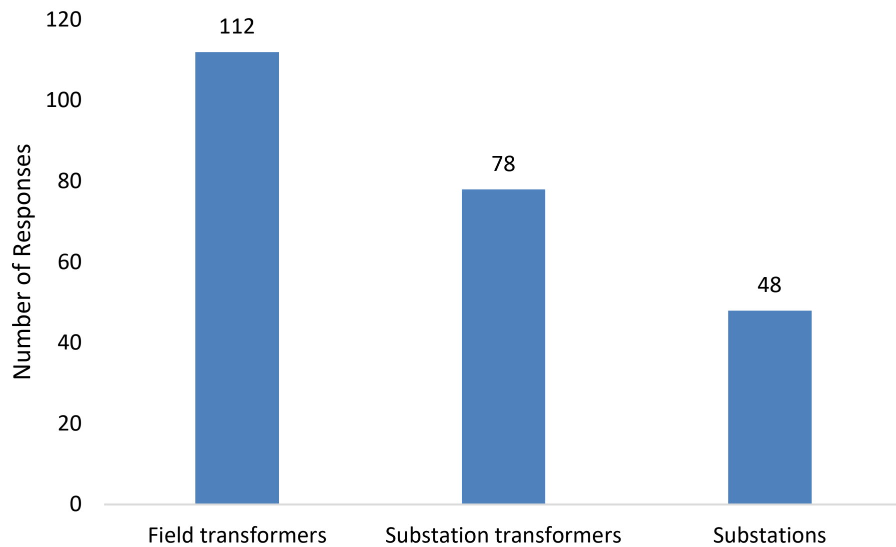


Figure 39: Count of work utilities allow developers to perform



Some utilities standardize the sizing of transformers, and substations. Figure 40 illustrates that it is most common to standardize the sizing of field transformers.

Figure 40: Count of system elements utilities standardize



Many utilities are curious as to how many kVA a typical customer uses. Based on the survey results, for new construction it looks like the average kVA of an installed transformer is 39.22 serving an average number of customers of 5.51. The overall data set from the survey shows an average of 6.85 kVA per customer, though the kVA per customer will certainly vary by climate region and house size.

SECTION IX: GENERAL UTILITY INFORMATION

The general utility information section of the survey was designed to help APPA understand the basic quantitative metrics of the utilities participating in the survey. The utilities that submitted information to this section of the survey gave valuable information for APPA's analysis of relationships between customers, lineworkers and line mileage. In addition, knowing the general characteristics of the survey participants can give perspective on the applicability of the results to certain utilities.

Since urban and rural were not strictly defined, a utility could use its own definition or the definition of urban as an overall average density of at least 500 people per square mile. Table 17 shows that the survey participants predominantly serve load in urban areas. It is important to note that the percentages shown below will not add up to 100 since they are averages of the load concentration percentages reported.

Table 17: Average percentage of rural and urban concentration per APPA region

Region	Urban (%)	Rural (%):
1	**87.00**	**13.00**
2	**80.50**	**19.50**
3	**85.50**	**14.50**
4	**83.4**	**16.40**
5	**74.33**	**25.67**
6	**85.92**	**14.08**
7	**79.27**	**20.73**
8	**56.25**	**43.75**
9	**56.00**	**44.00**

Table 18: Average and median number of customers served by survey respondents

	Average	Median
Residential	**31,810.50**	**10,273.00**
Commercial	**4,159.31**	**1,613.00**
Industrial	**134.47**	**25.50**
Total	**36,104.28**	**11,448.00**

Peak load can fluctuate on daily, monthly, yearly, etc. Figure 41 displays the average peak load reported by regions. Region 7 had a significantly higher peak load than the other regions during this period, which is likely due to a higher number of participants from that region representing more customers.

Figure 41: Average distribution system peak load per APPA region (in MW)

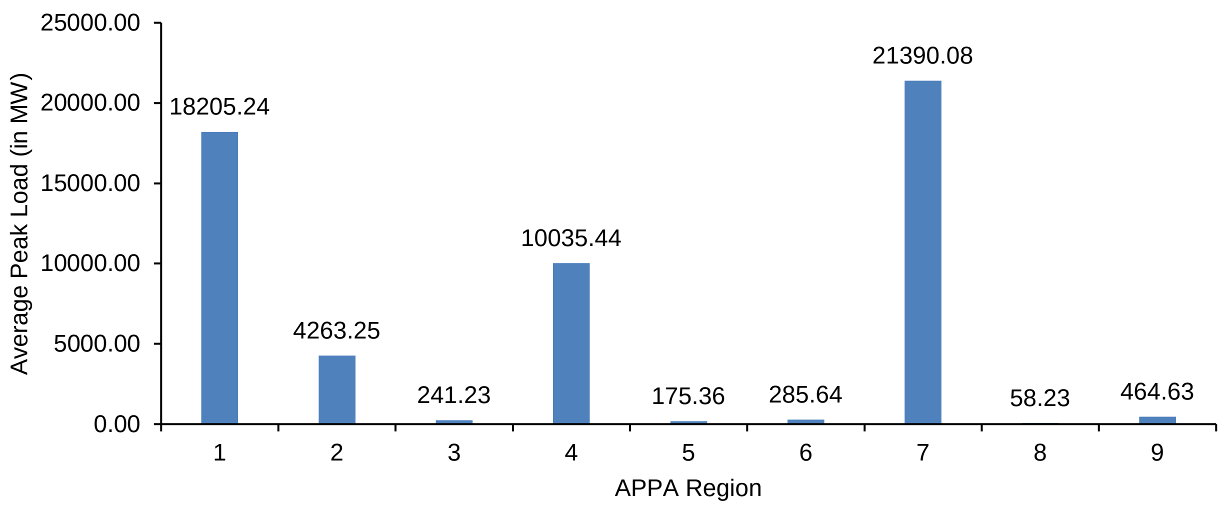
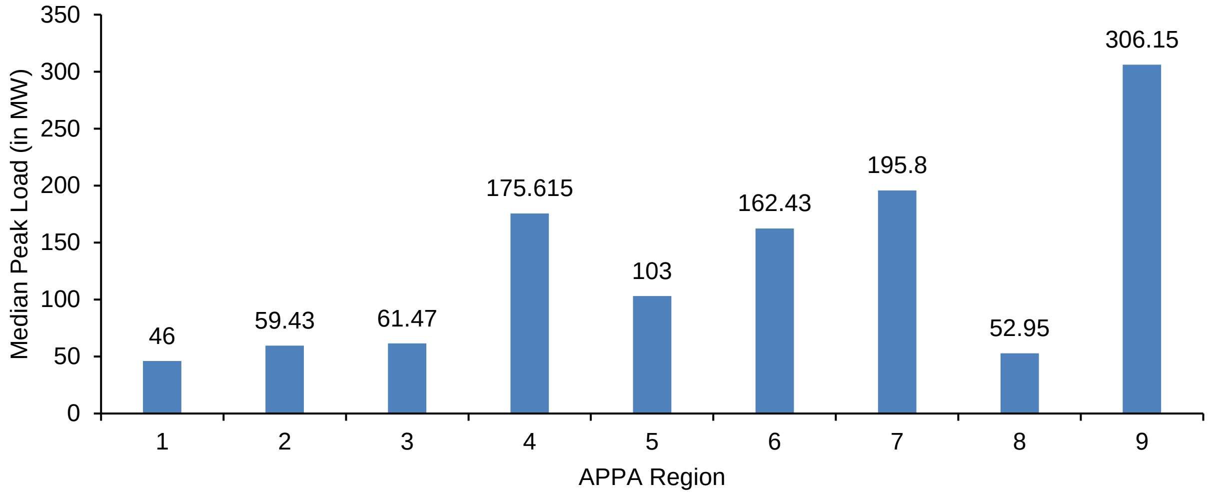


Figure 42: Median distribution system peak load per APPA region (in MW)



CONCLUSION

Starting or maintaining a program to track and evaluate reliability data is essential. Further, participation in APPA's Distribution System Reliability and Operations Survey is a beneficial exercise for engineers and operations personnel in the public power field. It is only through consistent and thoughtful participation that we will be able to explore in depth the issues that confront us as an industry. APPA hopes readers find this report both informative and valuable in their quest for operational excellence.

To measure system reliability successfully, utility staff should commit to the long-term uninterrupted collection of reliability related data. Measuring reliability is a deliberate process and takes a significant number of observations before it yields meaningful data. Commitment to measuring system reliability is a best practice and by participating in leading programs, such as APPA's Reliable Public Power Provider Program (RP3), a utility stands to gain significantly.

APPENDIX A – COPY OF QUESTIONS FROM DSR&O SURVEY

For a copy of the survey please see:

http://publicpower.org/files/2013_Distribution_System_Reliability_&_Operations_Survey.pdf

APPENDIX B – SUSTAINED AND MOMENTARY INTERRUPTION INDICES

Sustained Interruption Indices

Calculations of reliability indices as shown on survey. Please refer to IEEE Std. 1366 for a full description of each index; indices listed below should be used only by individuals familiar with reliability indices.

Average **S**ervice **A**vailability **I**ndex – ASAI is a measure of the average availability of the sub-transmission and distribution systems that serve customers. It is the ratio of the total customer minutes that service was available to the total customer minutes demanded in a time period. It is normally expressed as a percentage.

$$\textbf{ASAI} = \frac{\textit{Customer Hours Service Availability}}{\textit{Customer Hours Service Demand}}$$

System **A**verage **I**nterruption **F**requency **I**ndex (Sustained Interruptions) – This is defined as the average number of times that a customer is interrupted during a specified time period. It is determined by dividing the total number of customers interrupted in a time period by the average number of customers served. The resulting unit is "interruptions per customer".

$$\textbf{SAIFI} = \frac{\textit{Total Number of Customer Interruptions}}{\textit{Total Number of Customers Served}}$$

System **A**verage **I**nterruption **D**uration **I**ndex – This is defined as the average interruption duration for customers served during a specified time period. It is determined by summing the customer-minutes off for each interruption during a specified time period and dividing the sum by the average number of customers served during that period. The unit is minutes. This index enables the utility to report how many minutes customers would have been out of service if all customers were out at one time.

$$\textbf{SAIDI} = \frac{\sum \textit{Customer Interruption Durations}}{\textit{Total Number of Customers Served}}$$

Customer **A**verage **I**nterruption **D**uration **I**ndex – This is defined as the average length of an interruption, weighted by the number of customers affected, for customers interrupted during a specific time period. It is calculated by summing the customer minutes off during each interruption in the time period and dividing this sum by the number of customers experiencing one or more sustained interruptions during the time period. The resulting unit is minutes. The index enables utilities to report the average duration of a customer outage for those customers affected.

$$\textbf{CAIDI} = \frac{\sum \textit{Customer Interruption Durations}}{\textit{Total Number of Customer Interruptions}}$$

Customer **A**verage **I**nterruption **F**requency **I**ndex - The average frequency of sustained interruptions for those customers experiencing sustained interruptions.

$$\textbf{CAIFI} = \frac{\textit{Total Number of Customer Interruptions}}{\textit{Total Number of Customers Interrupted}}$$

Note *(Per IEEE P1366 – Guide for Distribution Reliability Indices)***:** For CAIFI index, in tallying the Total Number of Customers Interrupted, each individual customer should be only counted once regardless of the number of times interrupted during the reporting period.

Momentary Outage Indices

Momentary **A**verage **I**nterruption **F**requency **I**ndex – Total number of momentary customer interruptions (usually less than five minutes) divided by the total number of customers served.

$$\textbf{MAIFI}= \frac{\textit{Total No. Customer Interruptions(Monetary)}}{\textit{Total Number of Customers Served}}$$

System **A**verage **R**MS (Variation) **F**requency **I**ndex **-** Corresponds to a count or rate of voltage sags, swell and/or interruptions below a voltage threshold. For example, SARFI90 considers voltage sags and interruptions that are below 0.90 per unit, or 90 percent of a system base voltage. SARFI70 considers voltage sags and interruptions that are below 0.70 per unit, or 70 percent of a system base voltage. And SARFI110 considers voltage swells that are above 1.1 per unit, or 110 percent of a system base voltage. The SARFIX indices are meant to assess short-duration rms variation events only, meaning that only those events with durations less than 60 seconds are included in its computation.

$$\textbf{SARFI}_{\text{X\%- RMS Voltage Threshold (10 –140\%)}} =$$

$$\frac{\sum \begin{array}{l}\text{number of customers experiencing}\\ \text{short duration voltage deviations with magnitudes above X\%}\end{array}}{\begin{array}{l}\text{number of customers served from the section of the}\\ \text{system to be assessed}\end{array}}$$