American Public Power Association

Evaluation of Data Submitted in APPA's 2013 Distribution System Reliability & Operations Survey

NOTE

APPA 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. The data from this survey offer only a component of the conceptual benchmark/point for comparison and understanding of public power utility distribution system operations and reliability metrics.

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TABLE OF CONTENTS

INTRODUCTION

The 2013 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 and distribution system operations 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.

CUSTOMER SERVICE RELIABILITY

In the United States, a typical customer expects to have power at all times. In reality, a utility is able to make power available between 99.9 and 99.999 percent of the time. Some research has found that the average customer may be dissatisfied if he/she is without electricity for more than 53 minutes a year.[1] While at times unrealistic, customer expectations are driven in part by a lack of understanding of the institutional and organizational work required to maintain a continuous supply of electricity. Regardless of customer perception, these expectations are increasing public emphasis on utility reliability. Thus, standards-driven reliability programs can greatly assist in achieving reliability goals in a lowest-cost manner.[2]

Through their historical connection to consumers, publicly owned electric utilities are motivated to keep their local electric system operating continuously and efficiently. Providing power in the most reliable manner while keeping costs as low as possible is inherent to a nonprofit utility's nature. Maintaining that caliber of electric service is one of the core facets of a public power utility's business model.

SYSTEM RELIABILITY

Reliability, from a systems 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 see and show 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 impacts fundamental reliability. From substation and distribution design to fusing schemes, the physical factors of system design impact system reliability.

Many physical factors impact overall distribution 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 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 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 (line-losses), and fault tolerance.[3] 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.

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[1] Reliability Aspects of Power Plants, Jacob Klimstra, 2009
[2] Electric Power Distribution Reliability, Richard E. Brown, 2009
[3] Atsushi Tero, Et al. Rules for Biologically Inspired Adaptive Network Design, Science, Jan 2010

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 for that utility. Engineers 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, sag and swell, 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 its voltage transients and employ transient voltage surge suppression, VAR support, or other remediation. There are several resources available to help with this task.[4,5]

RELIABILITY STATISTICS AND THEIR USES

Reliability statistics are the quantitative basis for good decision making and come in many forms. On the whole, reliability statistics are excellent for self-evaluation. That's not to say utility-to-utility comparisons cannot be made, but differences in 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.

Utilities are assessed largely based on their rates and reliability. On average, public power utilities charge lower rates than investor-owned utilities.[6] Public power's rate advantage and superior reliability are key benefits of local public ownership of electricity resources and should be highlighted to customers to promote a utility. To properly promote these key characteristics of public power, it is important for a utility to track and evaluate reliability metrics.

Electric reliability data are also useful for promoting local economic development. Businesses want reliable electric service. This need is driven by the fact that momentary interruptions and power quality issues can lead to expensive downtime for sensitive manufacturing equipment. Once sensitive equipment is powered off, it must be restarted. For large machines, this restarting process can take a significant amount of time. In addition, some manufacturing processes are time-sensitive. In those cases, an incomplete production run could be lost during a sustained outage.

An integral part of distribution system reliability is power quality. To promote its power quality, a utility may consider presenting a quality index to potential customers. Typically, manufacturers operating in the area

[4] IEEE Recommended Practice for Grounding of Industrial and Commercial Power Systems, IEEE Std 142-2007
[5] IEEE Guide for Identifying and Improving Voltage Quality in Power Systems, Revision of IEEE Std 1250-1995
[6] http://www.publicpower.org/files/PDFs/PublicPowerCostsLess1.pdf

of Information Technology (IT) will rely on the Information Technology Industry Council (formerly known as the Computer & Business Equipment Manufacturer's Association (CBEMA)) curve to understand the quality of a utility's power supply.[7] This curve gives a voltage sag and event-duration envelope for alternating current (AC) systems that most IT equipment will tolerate. In addition, many businesses that use sensitive equipment will be attracted to comprehensive quantitative metrics, such as Momentary Average Interruption Frequency Index (MAIFI), for system performance.

STARTING POINTS FOR RELIABILITY

There are checklists for reliability metrics; however, 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[8]. 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.[9]

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.

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 together, indices, such as the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI), provide a comprehensive indicator of the total reliability of a utility's electric distribution system.

[7] ITI CBEMA Curve http://www.itic.org/clientuploads/Oct2000Curve.pdf
[8] Visit the eReliability Tracker website for more information: http://www.publicpower.org/reliability
[9] Visit the DEED website for more information: http://www.publicpower.org/deed

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.

Reliability statistics can help drive utility improvement programs. Nonetheless, when pursuing reliability improvement, taking a splintered approach can be damaging.[10] As such, utility managers should be sure to include all departments in a uniform plan to understand and act on reliability data. In some cases, a system reliability meeting will help bring other departments into the process of reinforcing system reliability. Whether a utility decides to use meetings or have technical specialists focus on the issues, it should be sure to identify gaps and create a uniform approach to reliability.

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.[11] 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 thunderstorm, 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.[12]

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

[10] APPA Reliability Standards and Compliance Symposium, Caribe Royale Resort Orlando, Florida, January 10, 2007
[11] Joseph H. Eto, et al., Lawrence Berkeley National Laboratory, Tracking the Reliability of the U.S. Electric Power System, 2008
[12] IEEE 1366-2003, B.5.1

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. The eReliability Tracker was created to aid utilities in their efforts to understand and analyze their outage data. The application allows utilities to effectively track, record, and evaluate their own outage history with advanced reporting functions in an intuitive and effective way.

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.[13]

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

OVERALL SURVEY INFORMATION

The data presented in this report are based on APPA's 2013 Distribution System Reliability and Operations Survey. The data reflect activity from January 1, 2012 to December 31, 2012. Any additional data presented are limited to specific reliability indices collected in the previous four 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 180, which is the total number of survey respondents for 2013. Alternatively, if the question only enables the respondent to select one option, the total number of responses to the question cannot be greater than 180.

The adverse part of conducting a survey with voluntary participation is the significant reporting bias encountered. 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. This skewing bias can take many forms. For example, a utility that is a likely participant in this survey will not be random. The participant has reliability metrics and most likely has a program to improve reliability. This type of informed participant could skew data toward the higher performing end of the spectrum. On the other hand, a utility with very poor reliability statistics wanting to participate and learn more about distribution system reliability, would submit its data without knowing if it would skew the data toward the lower-performing end of the spectrum.

Beyond reporting bias, there are regional dissimilarities. For instance, extreme weather is a regionalized and localized phenomenon. Under weather dissimilarity, areas hit with severe floods or storms will report comparatively high numbers. This will be especially true for utilities that do not exclude major event days. As with opposing reporting biases, the possibility of varied weather can provide 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.

Figure 1: Geographical map of APPA regions (Appendix C contains a larger map and a list of all the states within each region)

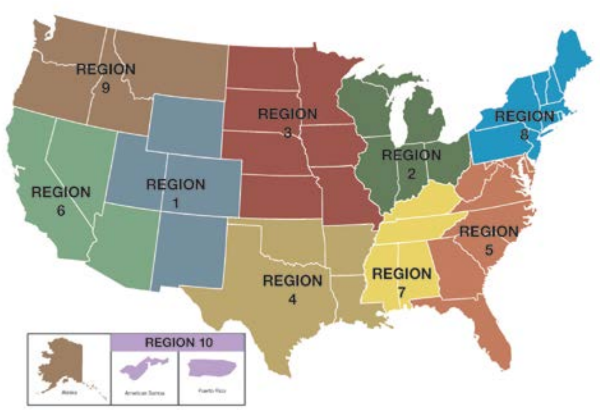
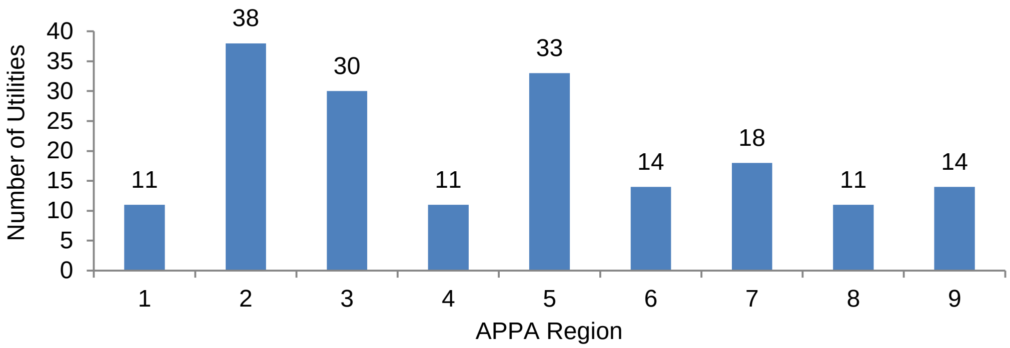
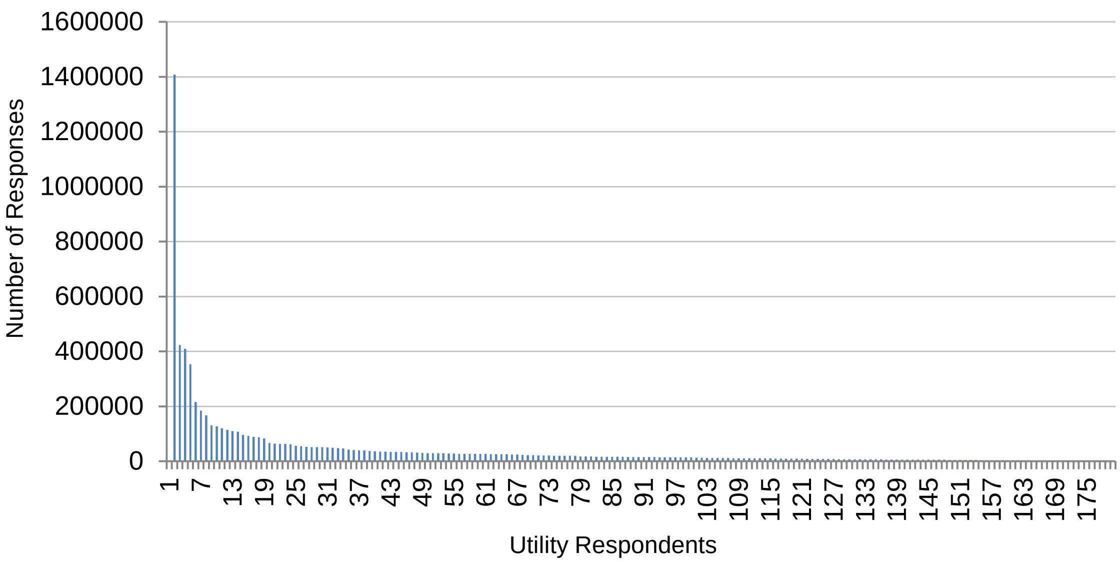


Figure 2: Count of utilities by APPA region



In total, 180 utilities from nine APPA regions participated in the 2013 reliability survey. This represents a 22 percent increase in survey participants from the 2011 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 five. The lowest concentration of participants is from regions one, four, and eight. In all, this survey represents 9 percent of public power utilities in the United States and more than 7 million utility customers.

Figure 3: Utility respondents arranged in order of decreasing number of customers



In figure 3, the number of customers for each utility that participated in the survey is shown in order of increasing customer size. Utilities with a wide variety of sizes responded to the survey questions. However, the vast majority of participants were small utilities. The average participant utility size was 40,731 customers and the median size was 15,657 customers up from an average of 34,668 and down from a median of 16,000 customers in the 2011 survey.

The following sections and their associated discussions are modeled after the layout and flow of the original survey.

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 in electricity service are costly for both utilities and communities.[14] 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 tracking 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: Types of outages tracked by utilities

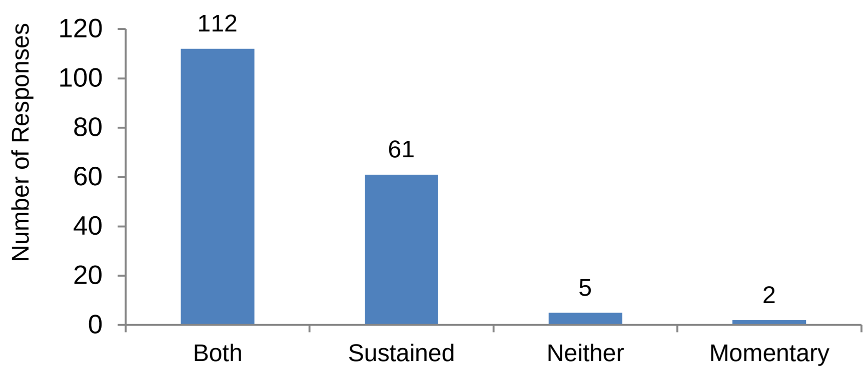
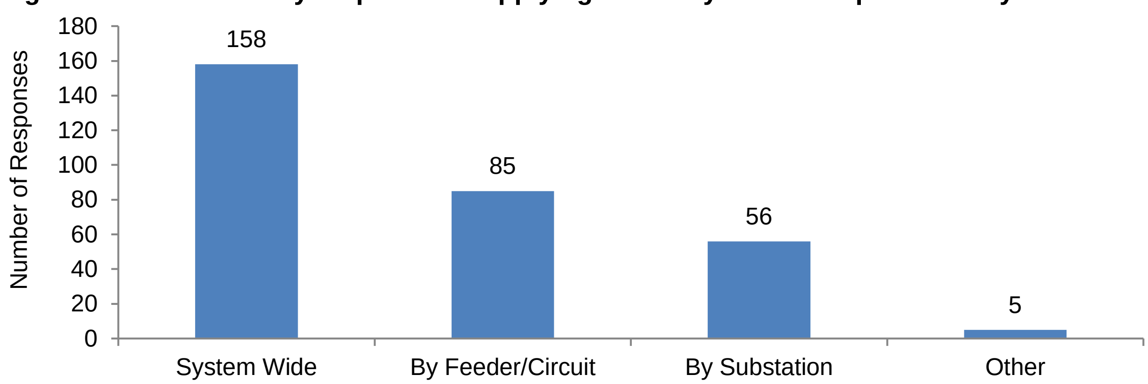


Figure 5: Count of utility respondents applying reliability indices at particular system levels



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

To record outages, utilities must decide which details should be kept in order to analyze the data more effectively when running reports. Table 1 contains the responses from utilities regarding their outage recording practices. Utilities could select as many types of information as applied in this question. The table includes types of data a utility may collect to calculate reliability statistics, understand outages and evaluate the long-term options for action.

Table 1: Count of respondents recording outage information

Date of Outage	176
Cause of Outage	173
Location of Outage	172
Length of Outage	170
Number of Customers Affected	166
Identification - Substation	127
Identification - Overhead	127
Identification - Underground	124
Partial Restoration of Power	116
Resolved/Needs Additional Work	111
Identification - Protective Device	106
Weather Conditions	103
Identification - Line (Single or Three)	103
Identification - Pole	91
Other	17

Participants were also 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. Many SCADA systems can report only on certain key points, leaving a utility to rely on customer call-ins to report many outages.

Table 2: Count of respondents that reported using outage tracking/recording technologies

SCADA System	92
Spreadsheet	78
Database	78
Paper Records	65
Outage Management System	58
eReliability Tracker Software	46
AMI/AMR/Smart Meters	20
Other	14

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.

Participants were also asked if they included planed outages in their reliability statistics. Though it is a near certainty that planned outages are evaluated on some level by many utilities, the information gained by looking at planned outages is used differently than that gathered for un-planned outages. Table 3 shows the way in which utilities treat their planned outages and major event days when calculating reliability statistics.

Figure 6: Count of respondents per method for calculating major events

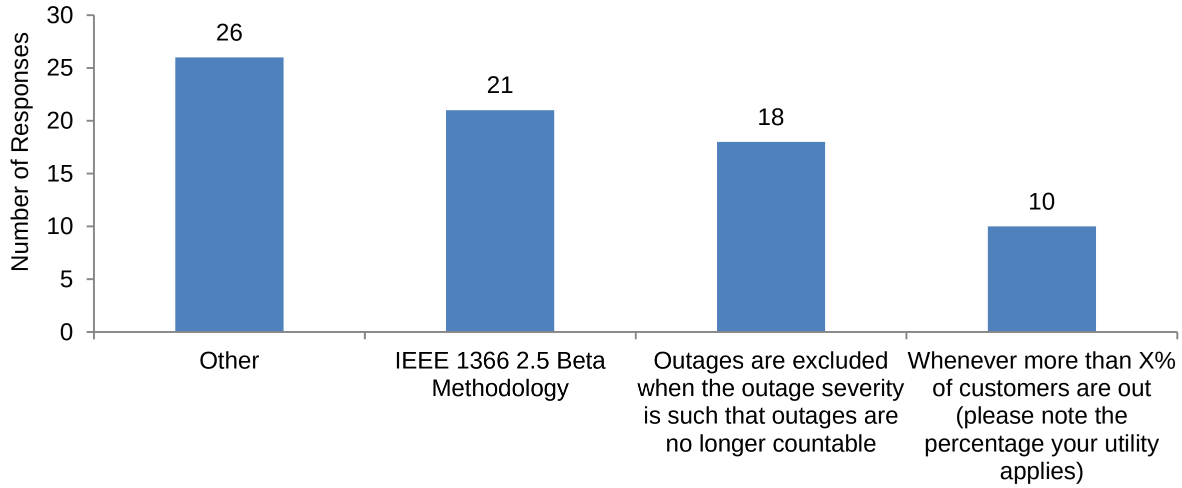


Table 3: Count of practices used for calculating and reporting reliability indices

	Yes	No
Do you include planned outages?	52	119
Do you include Major Event Days?	58	112
Does your utility generate reliability reports?	151	28
If yes, do you publicize those reports?	72	87

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.

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. 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. In Table 4, it can be seen that 29 respondents reported implementation of an automated switching scheme at their utility.

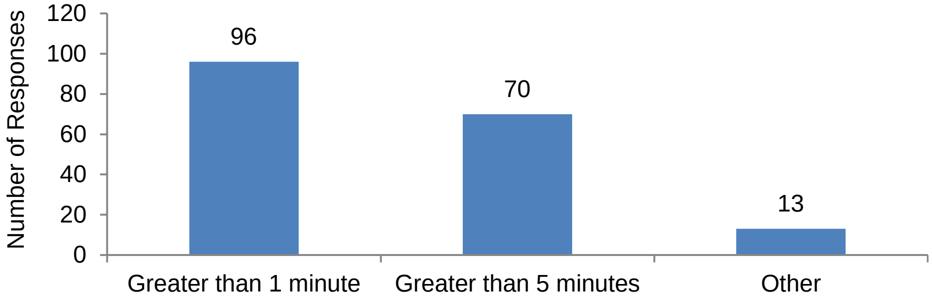
Table 4: Count of responses indicating implementation of an automated switching scheme

	Yes	No
Has your utility implemented an automated switching scheme?	29	150

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 7: Count of respondents' definition of a sustained outage



In the survey, utilities were asked for sustained outage reliability statistics collected from January 1, 2012 to December 31, 2012. 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 on the system. SAIDI is reported as the average duration in minutes of the interruptions. CAIDI is reported as the average length of time that a customer's outage lasts in minutes. ASAI is the percentage of time that the system was available 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 suggest that. Of the CAIDI metrics reported on this survey, 22 values do not comport with their corresponding SAIFI and SAIDI numbers by a 20% difference or more. To limit the effect this inconsistency may have on the aggregate data, all sustained reliability indices for those utilities were eliminated. This discrepancy may explain the differences between what one might expect for a CAIDI average and the CAIDI average of this data set. It is also important to note that it is unlikely for quartiles to result in a perfect SAIDI/SAIFI = CAIDI relationship.

For comparison, similar average statistics from the survey years 2005, 2007, 2009, 2011 and 2013 -- which represents data from years 2004, 2006, 2008, 2010 and 2012 respectively--are included in Table 6. No clear pattern or trend emerges from the analysis of the data sets over the years.

Table 5: Summary statistics of the 2012 reliability data submitted to the 2013 survey

	SAIFI	SAIDI	CAIDI	ASAI
Minimum	0.01	0.43	0.36	91.650
First Quartile	0.29	14.47	47.00	99.980
Median Quartile	0.63	40.40	69.70	99.990
Third Quartile	1.24	71.63	92.50	99.994
Maximum	23.00	552.84	2561.39	99.999
Average	1.11	58.49	96.47	99.878

Table 6: 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

Figures 8-11 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 8: Average SAIFI by APPA region

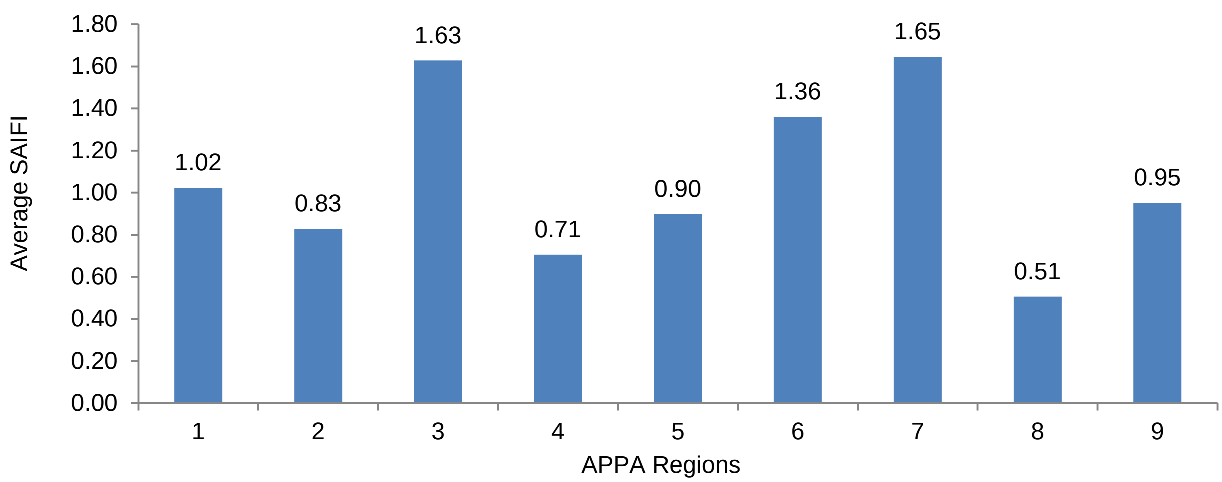


Figure 9: Average SAIDI by APPA region

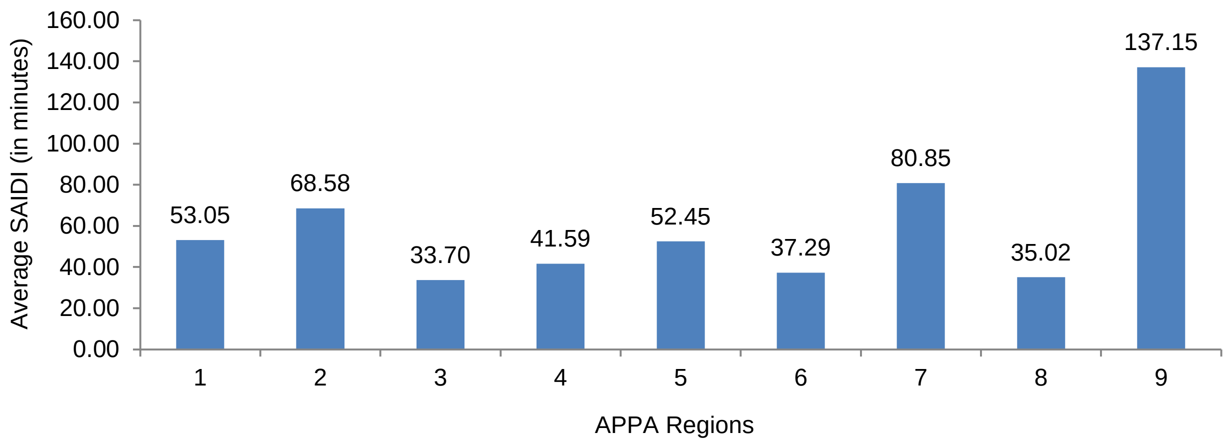


Figure 10: Average CAIDI by APPA region

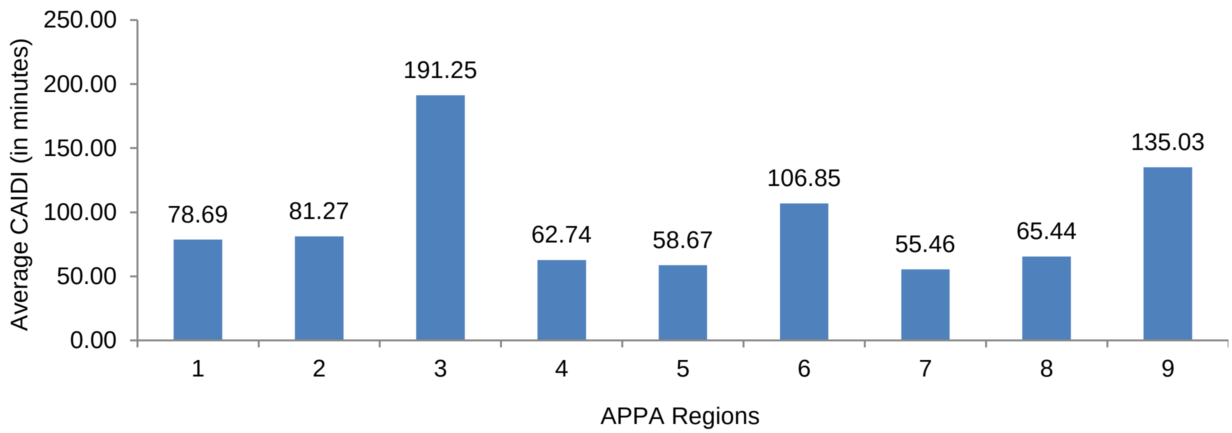
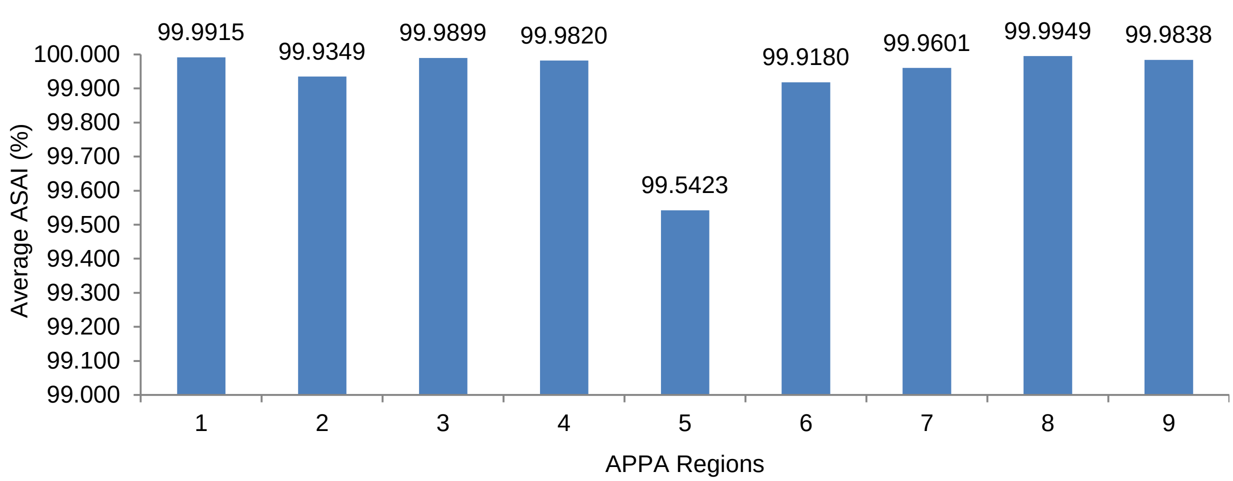
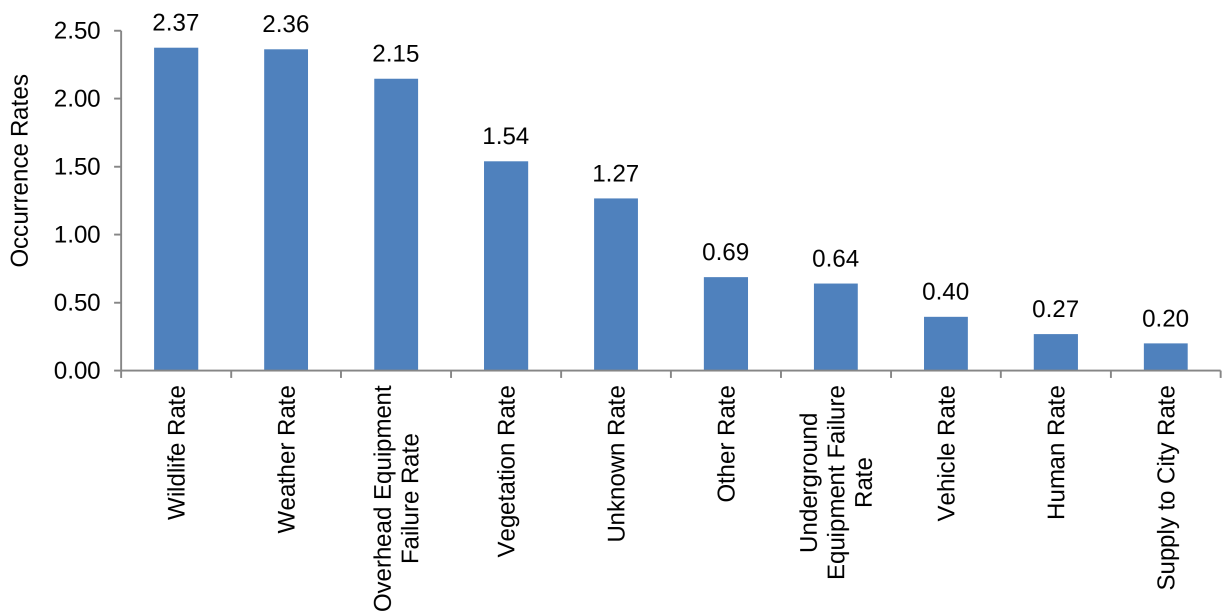


Figure 11: Average ASAI by APPA region



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. As seen in Figure 12, wildlife and weather are reported as the most significant causes of outages in 2012, which differs from the 2010 data where overhead equipment failure and weather were the top two causes. The use of the term “other” covered many outage causes not listed in the survey, such as excessive loading and scheduled maintenance.

Figure 12: Average customer-weighted occurrence rates per 1000 customers for common causes of sustained outages



As mentioned, wildlife is the most common cause among survey respondents. 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.

Figure 12 shows that weather is the second most common cause of outages. 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[15].

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

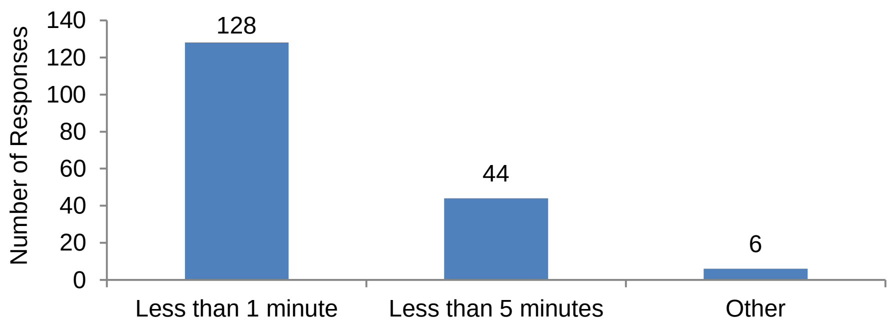
Overhead equipment failure is the third most common cause of sustained outages, and underground equipment failure is seventh. The clear implication is that preventative system maintenance programs can be a valuable tool to reduce outages. Similarly, vegetation is the fourth most common cause of outages. 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.[16] 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.

When tracking momentary outages, as with sustained outages, utilities define and capture them differently. Figure 13 shows how survey respondents define a momentary outage. According to the IEEE 1366 standards, a momentary outage is classified as any outage lasting less than five minutes. Alternatively, most survey respondents reported on classifying outages lasting less than one minute as momentary, which is consistent with the 2011 report.

Figure 13: Count of respondents per definition of momentary outages



Each utility's definition of a momentary outage can have a significant impact on their overall system's MAIFI. As seen in Table 7, the average frequency of interruption events for momentary outages is greater when the definition of the outage is shorter. This may have to do with enhanced technical monitoring ability in utilities with shorter definitions of MAIFI.

Table 7: Average MAIFI for utilities using a particular definition for momentary outages

	MAIFI
Less than 1 minute	2.51
Less than 5 minutes	1.35
Other	1.69

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 shows that trip and reclose

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

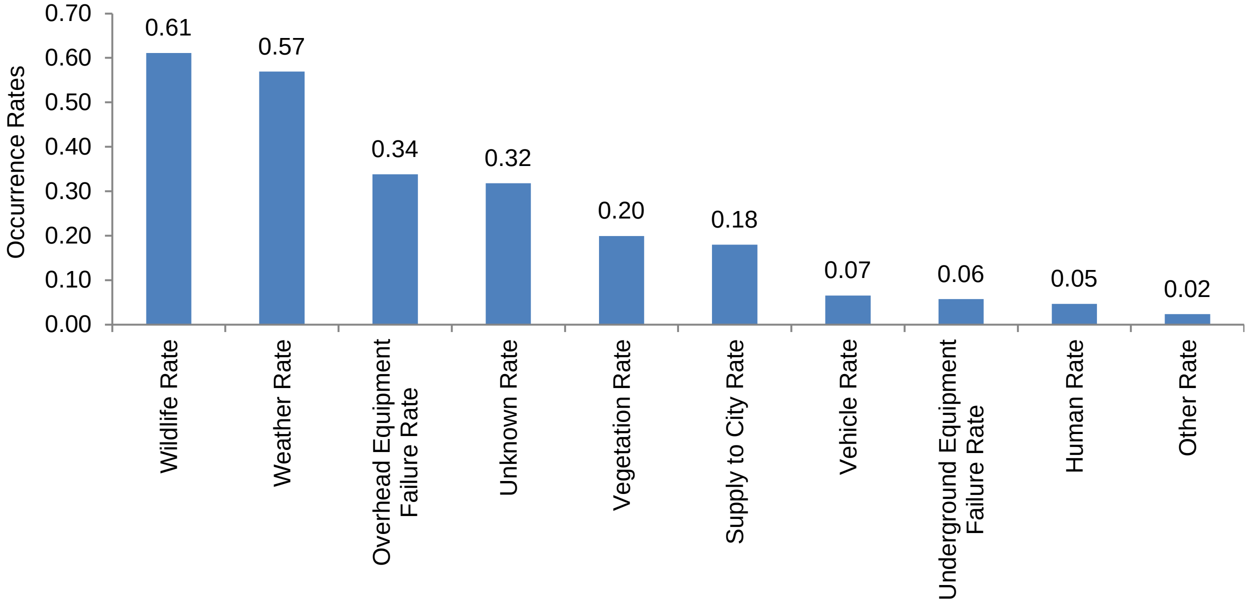
sequence with no lockout is the most common method to capture momentary outages in our respondent group.

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

Trip and Reclose sequence with no lockout	108
Individual trip and reclose events	76
"Customer call-in's"	53
Other	48
Via SCADA System	40
Via Outage Management System	21
Via AMI	14

Similar to sustained, 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, wildlife, weather, and overhead equipment failure are reported as the most significant causes of momentary outages in 2012, which is consistent with the 2011 survey results. In addition, the fourth and fifth most common causes, unknown and vegetation, are the same as the fourth and fifth on the sustained outage causes chart, but switched in ranking.

Figure 14: Average customer-weighted occurrence rates per 10000 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.

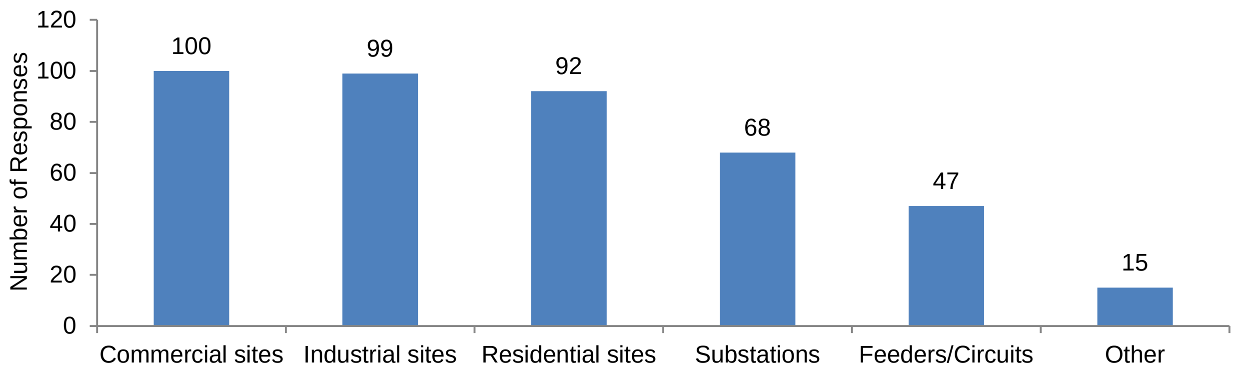
Many utilities limit the discussion of reliability to outages. However, power quality is a key component of reliability. Many standards address power quality.[17] Moreover, power quality issues vary in scope and addressability. On one hand, a utility can spend significant amounts of money to create a power system with a near-perfect sinusoidal voltage source, regardless of what is happening. On the other hand, a 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.[18]

Some utilities offer power quality monitoring services for their customers. For certain customers, this service can be valuable. It is most common among the survey respondents to perform power quality monitoring at commercial, industrial, and residential sites.

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



[17] See IEEE Std. 142, 519, 1159, 1250 and 1346
[18] Power quality primer By Barry W. Kennedy, 2000

In an electric distribution system, customer actions can impact the quality of system operation. Many of these customer actions are visible at other customer points of use. 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, and can be irritating to consumers. To address this 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.

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

Sag	110
Transient (spike)	84
Swell	76
Flicker	70
Total Harmonic Distortion (THD)	56
Noise	27
Frequency Variation	13
Other	7

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

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. Among programs identified by respondents, tree-trimming, as a subset of vegetation management, was most frequently selected to help reduce outages. To have an effective tree-trimming program, 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.[19]

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

Tree trimming	153
Animal/Squirrel guards	134
Routine distribution inspection and maintenance	123
Vegetation management	120
Thermographic circuit inspections	117
Lightning arresters	100
Review of worst performing circuit	97
Converted overhead to underground	80
Covered wire	63
Outage management system	56
Transformer load management	55
Root cause analysis	53
Circuit rider program	39
Other	20

Trees, while beloved by most customers, are ever-growing hazards for electric lines. When a tree or other vegetation makes 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.[20] 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. 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.

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[19] 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
[20] Electric Power Distribution Reliability, Richard E. Brown, 2009

Regular inspection, maintenance and outage-prevention programs can provide valuable reliability-related data to support decision making. Certain maintenance, such as tree trimming and visual inspection, should be performed regularly. 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. As was shown in Figures 12 and 14, wildlife is the most common cause of sustained and momentary outages in the 2012 data. 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. The count of utilities with major event plans and mutual aid agreements reflects a large portion of the survey respondents, which may accurately reflect public power's often quicker post-storm restoration times, compared with other utility types.

Table 11: Count of respondents with major event plans and count of those who participate in mutual aid agreements

	Yes	No
Do you have a major storm, event, or catastrophe plan?	155	23
If yes, is the plan written?	147	8
Does your utility participate in a mutual aid assistance agreement?	173	4
If yes, have you given aid using your mutual aid agreement?	*149*	*25*
If yes, have you requested aid using your mutual aid agreement?	*98*	*76*

Public power should be proud of its superb mutual aid and assistance network and should continue to improve it. This can happen by signing new mutual aid agreements or improving existing disaster management plans. To date, more than 1,600 municipally owned and rural electric cooperative utilities have signed the APPA/NRECA Mutual Aid Agreement. To get involved in APPA's Mutual Aid Working Group or for more information on the agreements, visit www.PublicPower.org/MutualAid.

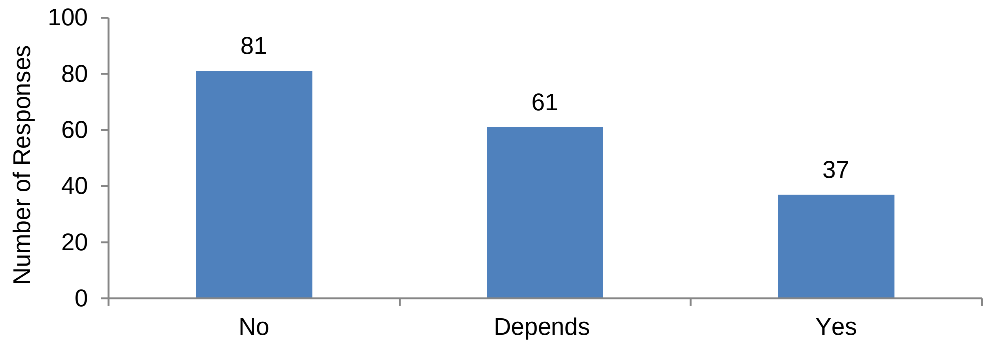
SECTION VI: WORK FORCE ISSUES

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.

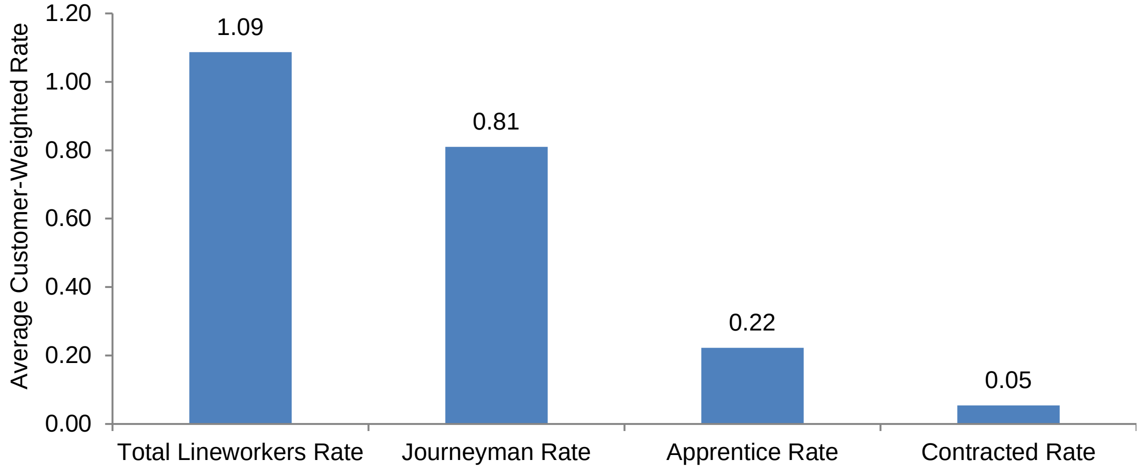
Figure 16: Method for providing 24 hour crew coverage

Figure 19: Count of respondents that allow or do not allow employees to take vehicles home



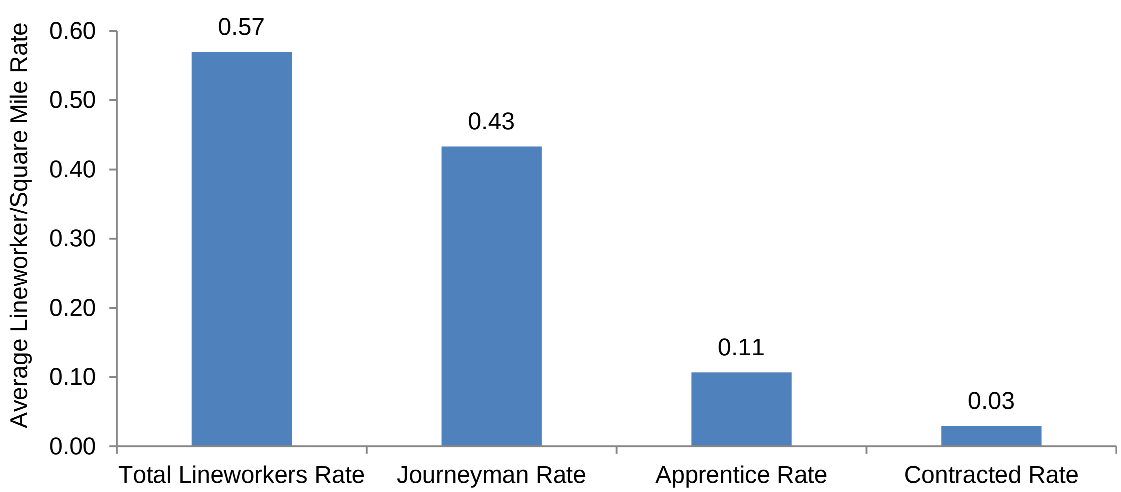
In the survey, the average number of crews that each utility employs was broken down into the categories of apprentice, journeyman, mixed and contract. There was significant variety in the number of lineworkers each utility employs. Figure 17 shows the average customer-weighted rate for employing the 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 17 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 17: 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 should not necessarily be a cause for worry.

Figure 18: Average rate of lineworkers per square mile

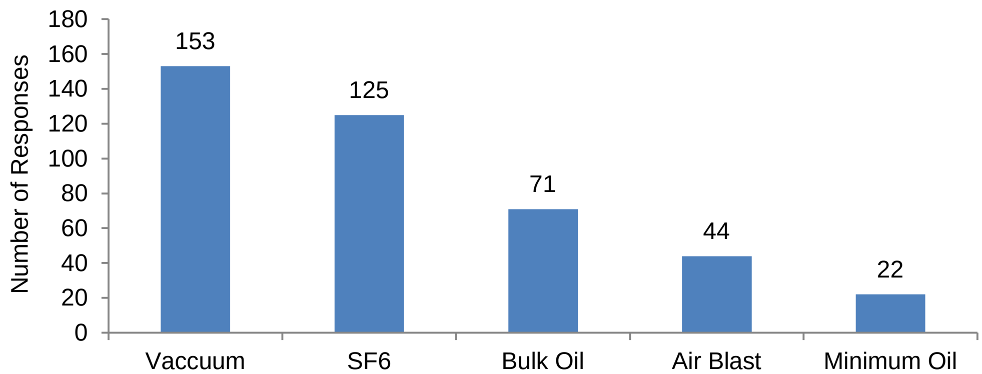


SECTION VII: SYSTEM OPERATION

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.[21] This section looks at specific system characteristics, such as types of materials used, transformer maintenance practices, and fault indication methods.

As the utility engineer 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.

Figure 20: Types of breakers used in utility substations



The survey asked participants about their transformer maintenance practices. Table 12 shows the breakdown of questions and responses from the survey on maintaining and testing transformers.

Table 12: Transformer maintenance and testing practices

	Yes	No
Do you have transformer overload guides?	129	46
Do you have an established transformer maintenance program?	156	22
Do you test transformer oil?	176	0
Do you use a standardized substation design for all of your substations?	101	73

Table 13 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.

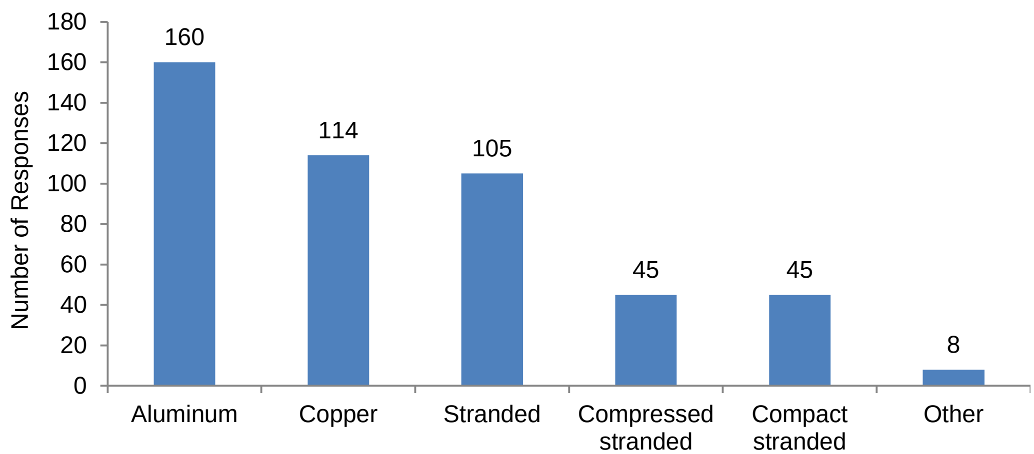
[21] Investigations of Temperature Effects on the Dielectric Response Measurements of Transformer Oil-Paper Insulation System, IEEE Transactions on Power Delivery, VOL 23, NO. 1, 2008

Table 13: Average and median customer-weighted rates per 1000 customers for distribution system components and characteristics

	Average	Median
Rate of distribution substations currently in operation	0.54	0.43
Rate of total distribution substation transformers currently in operation	3.09	0.63
Rate of total substation transformer capacity in MVA (Oil Air)	9.62	9.71
Rate of total installed distribution (field) transformer capacity	248.23	10.75
Rate of peak load in MW	13.98	5.73
Rate of service area in square miles	11.01	1.81

Figure 21 shows the various types of material composition used by respondents. Aluminum is the material most commonly used for primary feeder cables.

Figure 21: Types of material composition for primary feeder cables



The survey also asked utilities about the voltages they operate on their distribution system. Based on the ANSI C84.1 standard voltages, Table 14 shows that most participants indicated that they were using 12470Y/7200. Many utilities also noted that they were not using certain distribution system line voltages. Voltage data were collected to help utilities understand the decisions other utilities are making about distribution system voltage.

Table 14: Count of respondents operating at voltages overhead and underground

	Overhead	Underground
4160Y/2400	48	37
6900	5	4
8320Y/4800	8	7
12000Y/6930	6	9
12470Y/7200	97	94
13200Y/7620	26	26
13800Y/7970	27	28
20780Y/1200	5	6
22860Y/13200	9	8
23000	4	4
24940Y/14400	15	15
34500Y/19920	18	13
Other	17	13

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.[22] 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.

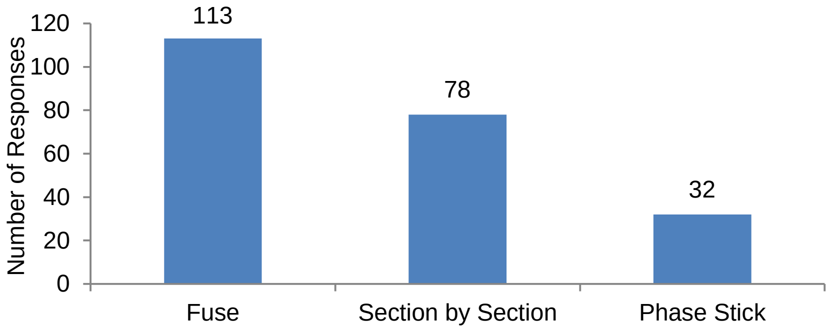
Table 15: Count of respondents practicing a distribution system fuse philosophy

Fuse Force (i.e. fuse blown prior to breaker operation)	116
Fuse Save (i.e. instantaneous trip first, then blow fuse)	58

The survey asked utilities to report the method used to locate faults. Figure 24 shows that fuse and section by section are the most commonly used.

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

Figure 24: Count of respondents per method to locate faults



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 25 shows the number of respondents using fault indicators on their overhead system, underground system, or both. Figure 26 further breaks down the data to display the common types of fault signals used.

Figure 25: Count of respondents using fault indicators on electrical systems that are overhead, underground, or both

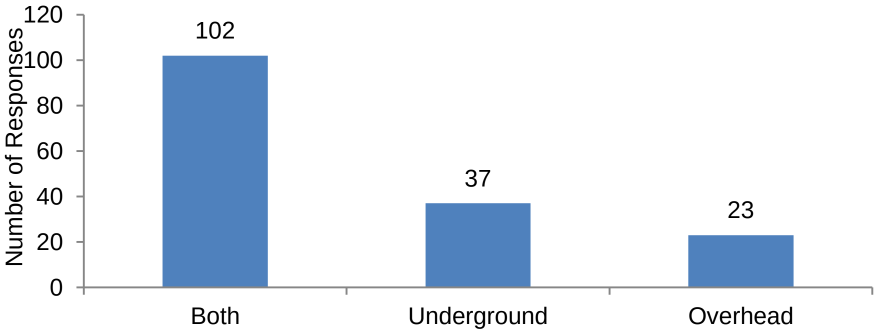


Figure 26: Count of respondents' using certain fault signals to indicate electrical faults

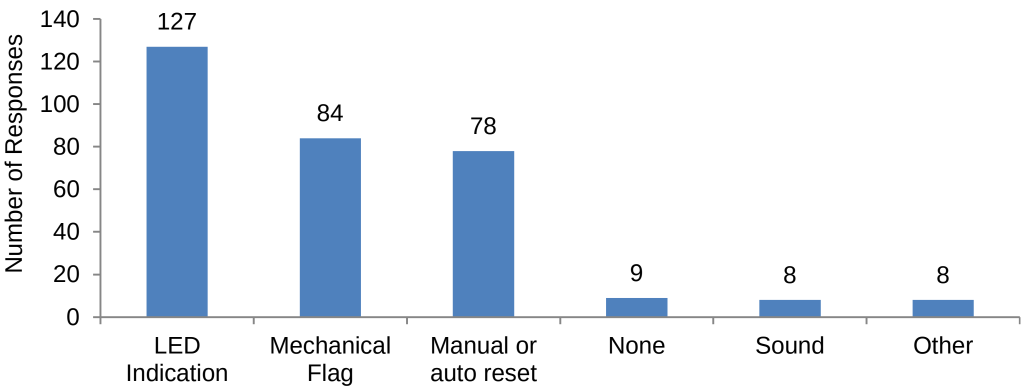
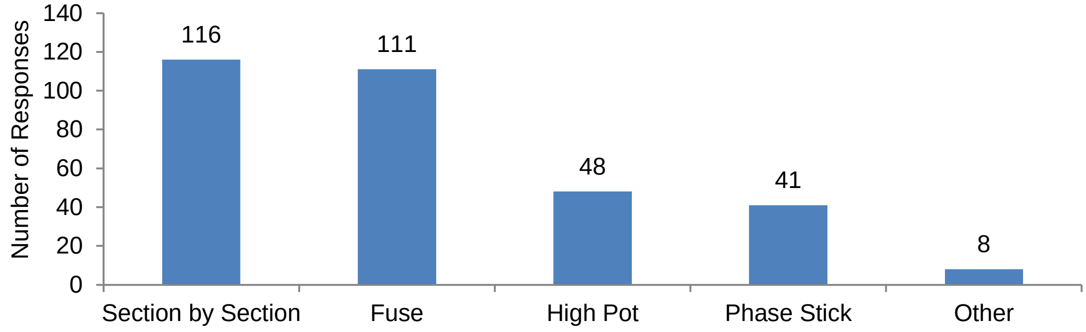
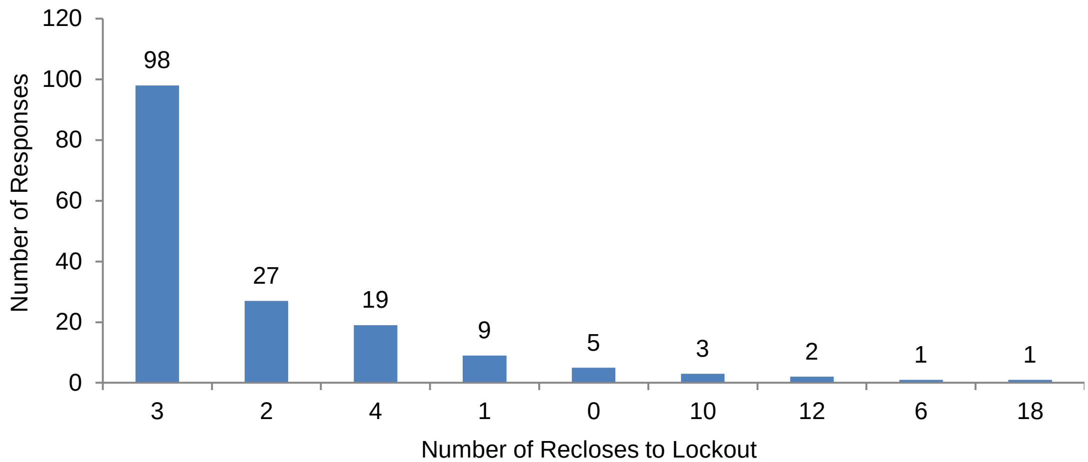


Figure 27: Count of respondents using common methods to sectionalize faulted sections of cable



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 16, 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.

Table 16: Average duration prior to reclosure (in seconds)

1st	3.75
2nd	10.18
3rd	19.57
4th	20.77

SECTION VIII: 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

	Urban (%)	Rural (%):
1	86.86	48.67
2	85.33	18.21
3	89.04	13.57
4	75.78	43.60
5	81.64	22.03
6	87.36	35.40
7	57.97	56.18
8	57.50	58.33
9	62.25	50.33
Overall	78.87	30.81

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

	Average	Median
Residential	33135.50	13350
Commercial	4291.08	1873.5
Industrial	1071.25	33
Total	40730.67	15657

Additionally, utilities were asked for the total number of miles of their system that is overhead and underground. Two utility respondents had a 100 percent underground electric system.

Table 19: Average number of miles overhead and underground

	Average	Median
Total miles overhead:	504.88	196
Total miles underground:	299.83	105

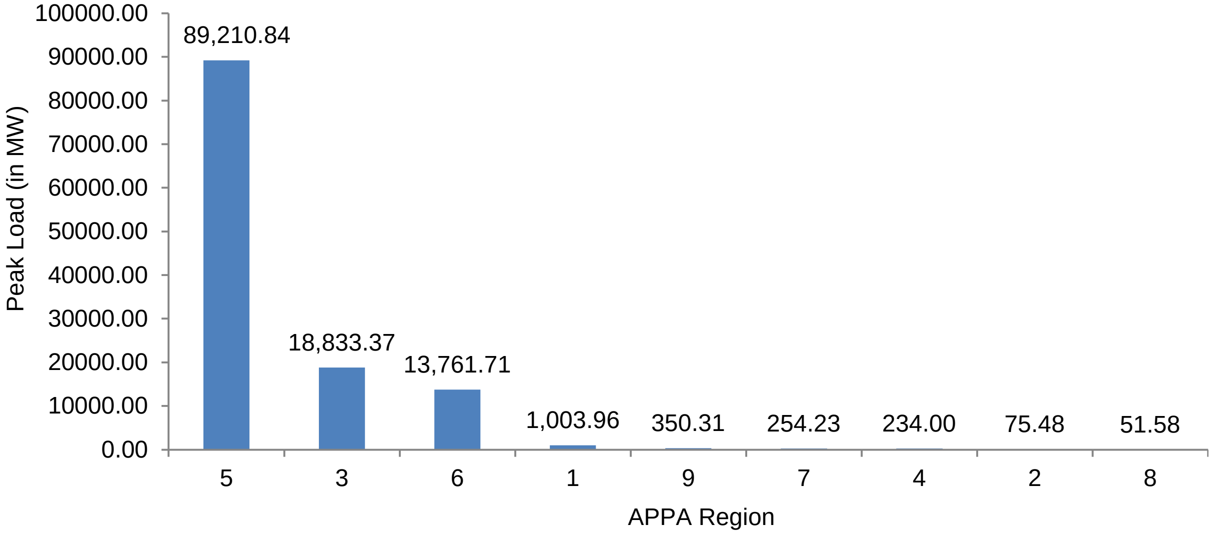
At many utilities in areas of high customer density or where greater system redundancy is needed, a networked distribution system configuration is used. Networked distribution can be thought of as multiple interconnecting electrical nodes. Table 20 shows that 153 respondents currently use a networked distribution system.

Table 20: Distribution system characteristics

	Yes	No
Does your utility have an initiative to convert existing overhead lines to underground?	106	70
Does your utility use a networked distribution system?	153	21

Peak load can fluctuate on daily, monthly, yearly, etc. The survey asked respondents for their utility peak load in 2012. Figure 29 displays the average peak load reported by regions. Region 1 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.

Figure 29: Average 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.

The data used in this survey represent a multitude of different takes on distribution systems and reliability, with a varied consistency in questions. For some questions, a secondary clarifying question may have helped create more uniformity in responses. On the whole, APPA believes this survey provides interesting and valuable benchmarking information to members regarding the way electric distribution systems are run across the public power industry. At best, this report expands individual understanding of electric utility distribution systems and conveys the general data collected in our survey.

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.

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

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".

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

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.

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

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.

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

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

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

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.

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

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

APPENDIX C – 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