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Tracking the Reliability of the U.S. Electric Power System:

An Assessment of Publicly Available Information Reported to State Public Utility Commissions

Joseph H. Eto and Kristina Hamachi LaCommare

October 2008

The work described in this report was funded by the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Disclaimer

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Abstract

Large blackouts, such as the August 14-15, 2003 blackout in the northeastern United States and Canada, focus attention on the importance of reliable electric service. As public and private efforts are undertaken to improve reliability and prevent power interruptions, it is appropriate to assess their effectiveness. Measures of reliability, such as the frequency and duration of power interruptions, have been reported by electric utilities to state public utility commissions for many years. This study examines current state and utility practices for collecting and reporting electricity reliability information and discusses challenges that arise in assessing reliability because of differences among these practices. The study is based primarily on reliability information for 2006 reported by 123 utilities to 37 state public utility commissions.

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Acronyms and Abbreviations

ASAI	Average Service Availability Index
CAIDI	Customer Average Interruption Duration Index
CD	Census Division
DAWG	Disturbance Analysis Working Group
DC	District of Columbia
DOE	U.S. Department of Energy
EIA	Energy Information Administration
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
LBNL	Lawrence Berkeley National Laboratory
MAIFI	Momentary Average Interruption Frequency Index
MED	major event day
MW	megawatt (10^6 watts)
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NRRI	National Regulatory Research Institute
OE	DOE Office of Electricity Delivery and Energy Reliability
PUC	Public Utility Commission
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

Executive Summary

Large blackouts, such as the August 14-15, 2003 blackout in the northeastern United States and Canada, focus attention on the importance of reliable electric service. As public and private efforts are undertaken to improve reliability and prevent power interruptions, it is appropriate to assess their effectiveness. Measures of reliability, such as the frequency and duration of power interruptions, have been reported by electric utilities to state public utility commissions (PUCs) for many years. This study examines current state and utility practices for collecting and reporting electricity reliability information and discusses challenges that arise in assessing reliability because of differences among these practices.

To collect information on current practices and rules that guide utility-reported reliability information, we contacted all 50 state PUCs as well as the District of Columbia (DC) PUC. When permitted by state practices, we also collected a large sample of publicly available, actual reliability information reported by utilities to the PUC for year 2006. In total, we received information provided by 123 utilities to 37 state PUCs (see Figure ES-1). In aggregate, the reliability information we collected represents over 77% of total electricity sales by state-regulated investor-owned utilities or nearly 60% of total U.S. electricity sales.

Our assessment focused on three reliability metrics: System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI). SAIDI and SAIFI measure the duration and frequency, respectively, of sustained interruptions; MAIFI measures the frequency of momentary interruptions. Taken together, these three metrics can be used to develop a comprehensive assessment of reliability nationwide.

Our findings regarding state PUC practices and rules on reliability information reported by utilities are summarized as follows:

- Thirty-five state PUCs, including DC, require routine reporting of reliability event information. This is a net increase of 10 state PUCs over the number reported in a similar survey conducted by the National Regulatory Research Institute (NRRI) in 2004.
- These 35 PUCs require annual reporting of SAIDI and SAIFI and/or the Customer Average Interruption Duration Index (CAIDI), which, along with SAIFI, can be used to derive SAIDI. Only two state PUCs require reporting of MAIFI.
- Twenty-one PUCs have reporting requirements that formally define major events. Of these 21, four require reporting following the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003, IEEE Guide for Electric Power Distribution Reliability Indices, which introduces a consistent means for defining major events using the concept of “major event days.”
- An additional four PUCs receive reliability information from utilities, though not as a result of a formal reporting requirement.
- Thirty-seven state PUCs, including DC, make publicly available or summarize in publicly available documents, the reliability information they collect from utilities.

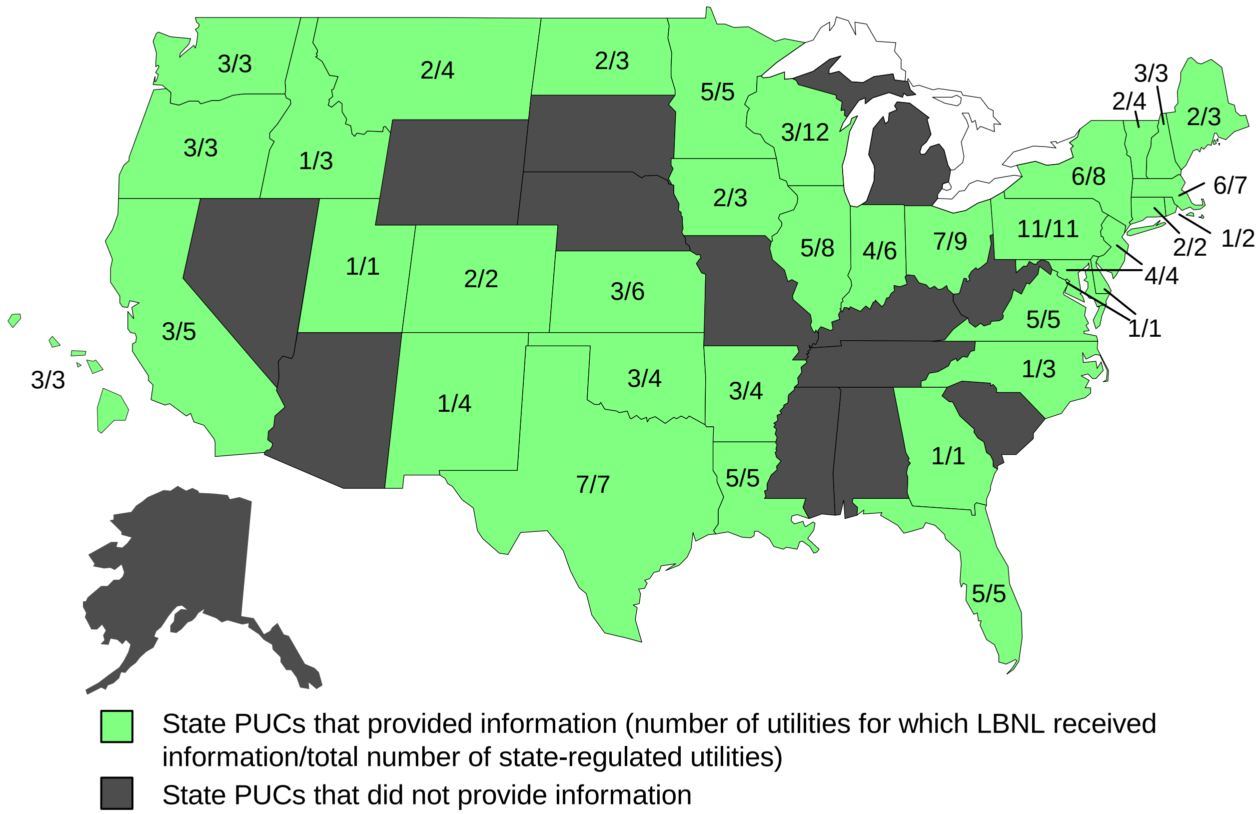


Figure ES- 1. Summary of States that Provided Utility-Reported Reliability Information

Our findings regarding utility practices for collecting and reporting reliability information to state PUCs are summarized as follows:

- All utilities reported SAIDI and SAIFI (and/or CAIDI). Only 12 of the 123 utilities reported MAIFI.
- Summary statistics for reported SAIDI, SAIFI, and MAIFI exhibit observable though not statistically significant variations across census regions.
- The definition of and practices for recording sustained and momentary interruptions have evolved over time leading to inconsistencies among utilities.
- Differences in the definition of a sustained interruption do not appear to affect SAIDI or SAIFI in a statistically significant manner.
- Utilities define major events as a means for distinguishing between utility performance in planning for and responding to routine interruptions versus that for non-routine or extraordinary interruptions.
- The definition of a major event is not consistent among the majority of utilities.
- IEEE Standard 1366-2003 introduces a consistent means for defining major events using the concept of “major event days.”
- Some utilities report SAIDI and SAIFI both including and not including major events; other utilities only report SAIDI and SAIFI not including major events.
- When major events are not included, SAIDI is lowered relatively more than SAIFI compared to when major events are included.
- Many utilities report descriptive information on each major event.

- Use of IEEE Standard 1366-2003 does not appear to bias SAIDI or SAIFI values compared to using prior definitions of major events.

We also collected information on bulk power system emergencies reported by utilities in near real-time to national bodies in 2006, including the U.S. Department of Energy (DOE) and the North American Electric Reliability Corporation (NERC), and compared aspects of this information to that reported by utilities to state PUCs. Our findings are summarized as follows:

- Information on electricity reliability reported to these two national bodies consists of descriptive information that is reported in near real-time on individual, large events that affect the bulk power system. The reporting takes place in near real-time because an important purpose of the reporting is to notify relevant industry and public bodies of significant power system events that may require immediate response. With few exceptions, the same information is reported to both DOE and NERC at the same time.
- Many, but not all, events reported to these national bodies also cause power interruptions to customers. For these events, the number of customers affected is reported.
- An initial assessment of these events supports the conventional wisdom that the majority of power interruptions experienced by customers are not due to large events that affect the bulk power system; they are due to more localized events that affect only utility distribution systems.
- It is difficult to cross-reference information reported to national bodies on individual large bulk power system events that cause power interruptions, as defined by these national bodies, with information reported to state PUCs on individual major events, as defined by either the PUC or the reporting utility.

From these findings, we draw the following conclusions and recommendations:

- State PUC interest in electricity reliability is growing.
- However, differences in utility reporting practices hamper meaningful comparisons of reliability information reported by utilities to different state PUCs and, therefore, may limit the effectiveness of efforts to measure the effectiveness of efforts to improve reliability.
- Efforts to eliminate differences that are solely due to reporting practices are just beginning. These efforts, which focus on using standard definitions, such as those promoted by IEEE Standard 1366-2003, are promising and should be encouraged.
- Until IEEE Standard 1366-2003 is adopted universally, regulators concerned about the definition and treatment of major events in reporting reliability information should consider requiring reporting of SAIDI and SAIFI both including and not including major events, as well as descriptive information on each major event.
- More work is required to better understand the sources of discrepancies and the importance of seeking greater consistency between reliability information reported to national bodies and that reported to state PUCs.

1. Introduction

Large blackouts, such as the August 14-15, 2003 blackout in the northeastern United States and Canada, focus attention on the importance of reliable electric service. Acknowledged as the largest power outage ever to occur in North America, the 2003 blackout affected more than 50 million people in eight U.S. states and two Canadian provinces; some customers were without power for more than two days. The final blackout investigation report contained 46 recommendations to improve electricity system reliability and prevent future blackouts (Department of Energy 2004).

As a result of this major blackout, public and private efforts have been proposed to improve reliability and prevent future power interruptions, both large and small. It is important to assess the effectiveness of these efforts. A common management precept is that you cannot manage something effectively unless you can measure it. Performance metrics, similar to the letter grades assigned in school, are a way to quantitatively measure reliability and improvements in it.

Lagging measures of reliability, so called because they are retrospective, have been recorded by electric utilities for many years. These metrics, such as the frequency and duration of power interruptions, have been an essential tool for managing reliability because they provide a quantitative, objective basis for judging the effectiveness of the organization's efforts to maintain or improve reliability. These data have supported organizations' and regulators' efforts to monitor reliability performance and to compare performance to benchmarks or trends, so that these entities can initiate corrective actions when necessary to improve performance.

This study presents findings on current state and utility practices for collecting and reporting reliability information and discusses challenges that arise in assessing reliability as a result of differences among these practices. We pay special attention to the effect of the recent adoption of the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003, IEEE Guide for Electric Power Distribution Reliability Indices (IEEE Power Engineering Society 2004), which formally defines the major reliability metrics and the factors and procedures used to calculate them (see Text Box).

Although a variety of reliability metrics exist, we focus primarily on practices associated with two of the most commonly reported metrics, the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). Both are used to describe interruptions of a defined minimum duration. We also focus on a less commonly reported metric, the Momentary Average Interruption Frequency Index (MAIFI),[1] which captures interruptions that are shorter in duration than those recorded for SAIDI and SAIFI. Taken together, the three metrics can be used to comprehensively assess reliability nationwide (LaCommare and Eto 2004).

To conduct the current study, we contacted public utility commissions (PUCs) in all 50 states plus the District of Columbia (DC) to gather information on practices and rules related to utility-reported reliability information for year 2006. When permitted by state practices, we collected a

[1] For technical information on the definitions and calculation of SAIDI, SAIFI, and MAIFI, please see Appendix A.

large sample of publicly available reliability information reported by utilities for 2006. We chose to focus on state PUCs and state-regulated investor-owned utilities because many state PUCs already routinely collect this information from the utilities they regulate and because these utilities, taken together, account for a significant share of total sales of electricity in the U.S.

We first developed descriptive statistics, organized by Census Division regions, on the information reported by utilities. We then examined the impact of differences in utility reporting practices on the reliability indices.

We also collected information on electricity reliability reported by utilities to national bodies on large power system emergencies that sometimes cause power interruptions, including both the U.S. Department of Energy (DOE), and the North American Electric Reliability Corporation (NERC), and compared aspects of this information to the information reported by utilities to state PUCs.

The remainder of this report is organized as follows:

- Section 2 describes the rationale for and the results of our contacts with state PUCs.
- Section 3 presents findings on state PUC practices and rules that affect reliability information reported by utilities.
- Section 4 presents qualitative and quantitative findings on utility practices for collecting and reporting reliability information to state PUCs.
- Section 5 presents findings from efforts to compare information on bulk power system electricity emergencies that cause power interruptions and are reported in near real-time to national bodies to the reliability information provided to state PUCs on a routine basis.
- Section 6 summarizes all of our findings and conclusions.

IEEE Standard 1366-2003

The IEEE established the Standard 1366 for defining reliability indices in order to:

“present a set of terms and definitions which can be used to foster uniformity in the development of distribution service reliability indices, to identify factors which affect the indices, and to aid in consistent reporting practices among utilities” (IEEE Power Engineering Society 2004).

IEEE Standard 1366-2003 is a voluntary means to derive consistent reliability metrics that can be effectively evaluated for decision making and policy-making purposes (Gonzalez 2006). It provides definitions for SAIDI, SAIFI, CAIDI, etc including methods for calculating these statistics. The goal is for all utilities and entities that need a methodology for estimating reliability at the distribution level to adopt this standard so that all utilities have a consistent benchmark for comparison and reporting across the U.S. (Warren 2006).

IEEE Standard 1366-2003 is an update of previous versions (i.e., 1366-1998 or 1366-2001), which is designed to define in a consistent manner reliability indices as well as major events that affect utility distribution service territories.

The IEEE Standard 1366-2003 standard defines a new method for identifying major events, called the “2.5 beta method.” A Major Event Day is defined as a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. The threshold value is calculated using statistical criteria to identify events that are significantly different from the majority of events experienced in recent years (up to five sequential years of historical data). The methodology is described in greater detail in Appendix A.

2. The Rationale for, and Process and Results of Contacts with State PUCs

To conduct this study, we contacted all 50 state PUCs plus DC to gather information on current practices and rules that guide utility-reported reliability information. When permitted by state practices, we also collected actual reliability information reported by utilities for year 2006. This section describes the rationale for, questions asked during, and results of our contacts with state PUCs.

2.1 Why Focus on State PUCs and State-Regulated Utilities?

We chose to contact state PUCs for several reasons. First, the utilities they regulate, investor-owned utilities (IOUs), collectively account for the majority of total U.S. electricity sales (nearly 75%). Second, state PUC oversight of these utilities relies on information that is routinely provided by the regulated utility to the PUC, including information on reliability. Third, state PUCs make much of the information they receive from the regulated utility publicly available, pursuant to administrative rules established by the state.

We anticipate future work that will collect and assess publicly available utility-reported reliability information from other sources, such as utility industry trade associations, federal utility lending agencies, and of course directly from individual utilities.

2.2 What Did We Ask Each State PUC?

We asked each PUC the following questions:

- Does your state require utilities to submit reliability information to the PUC?
- If so, do the requirements call for routine (e.g., annual) submission of this information?
- What reliability information (e.g., indices) is submitted?
- How do reporting practices or rules guide the definition of sustained interruptions and major events used to calculate the major reliability indices? Specifically, has the state adopted the recent IEEE Standard 1366-2003, which formally defines these indices and how these factors should be used to calculate them?
- What are the practices or rules for reporting reliability indices with major events included and not included?
- What are the practices or rules guiding reporting on individual major events?
- Does the PUC make publicly available either the reliability information provided to the PUC or summaries of this information?
- If so, can you provide our research team with whatever utility-reported reliability information is readily available?

The information we collected reflects state PUC practices that were current in 2006.

2.3 What Utility-Reported Reliability Information Did We Collect?

We contacted every state PUC as well as DC to obtain information on current state reporting requirements.[2] The findings from this portion of our research are reported in Section 3. We were also able to obtain 2006 reliability information for 123 utilities from 37 PUCs including DC. These findings are reported in Section 4.

Figure 1 shows the 37 states (including DC) that provided utility-reported reliability information. The fourteen states we were not able to obtain utility-reported reliability information are shown in dark gray shading. Figure 1 also tabulates the number of utilities for which we obtained reliability information (numerator) compared to the total number of regulated-investor-owned utilities within the state (denominator). In an effort to collect as much utility-reported reliability information as possible and at the same time respect the workload of state PUC staff, we requested only readily available information. In some cases, we received annual summaries that PUC staff had prepared by tabulating information from individual reports submitted by each utility in the state. In other cases, we received copies of some, but not necessarily all, of the individual reports submitted by the utilities.

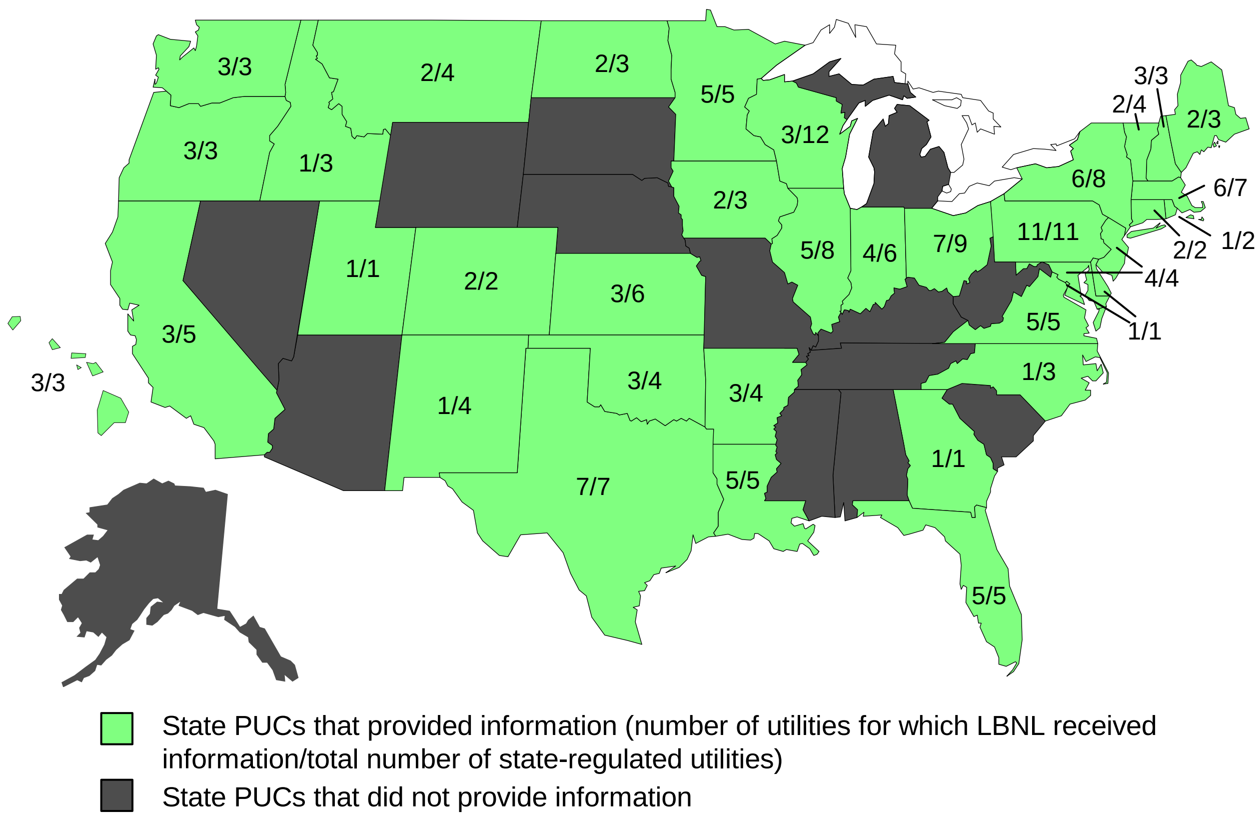


Figure 1. Summary of States that Provided Utility-Reported Reliability Information

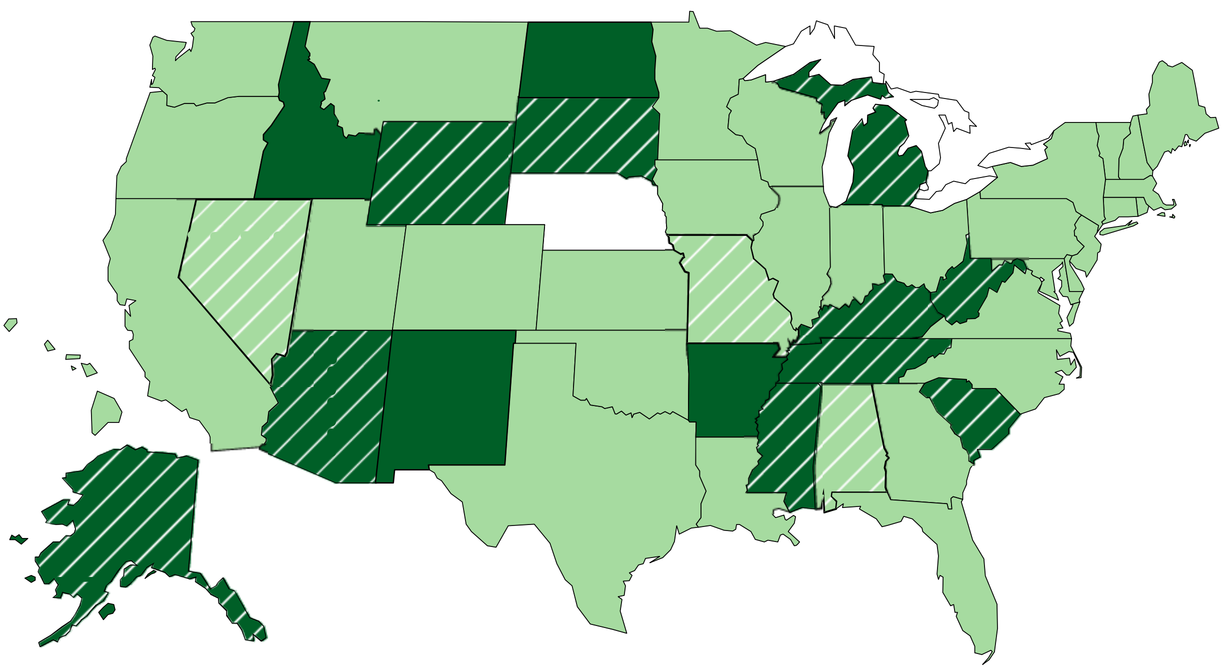
[2] Note: There are no state-regulated electric utilities in Nebraska; thus, this state was not contacted.

3. Review of State Reporting Requirements and Practices for Utility Reliability Information

We contacted PUCs in every state and DC to obtain information on current state reporting requirements for utility reliability information.[3] This section presents our findings on overall state reporting requirements and practices, changes in reporting requirements over time, and the specificity of state requirements regarding the types of reliability information that must be reported and the definitions of major events. The information we report reflects state practices, as of 2006.

3.1 Requirements for Routine Reporting and Practices for Public Availability of Reported Information

We find that 35 PUCs, including DC, require that reliability information be reported routinely. An additional four state PUCs receive reliability information from utilities though not in response to a formal reporting requirement. Thirty-seven state PUCs, including DC, make publicly available or summarize in publicly available documents the reliability information they collect from utilities.



PUC requires routine filing by utilities and makes this information publicly available
PUC requires routine filing by utilities, but does not make this information publicly available
PUC does not require routine filing by utilities, but makes this information publicly available
PUC does not require routine filing by utilities and does not make this information publicly available
No state-regulated utilities

Figure 2. State Reporting Requirements and Practices for Utility-Reported Reliability Information

[3] As noted previously, there are no state-regulated electric utilities in Nebraska; thus, this state was not contacted.

Figure 2 combines information on state reporting requirements with information on state practices regarding the public availability of reported information. The 33 states shown in light solid shading, including DC, currently require utilities to report reliability information and make this information publicly available (either the actual reports submitted by the utilities or summaries prepared by PUC staff). The four states denoted by solid dark shading do not require utilities to report reliability information, yet did have information they were willing to share with us.[4]

The 13 states shown in dark and light-striped shading either do not require or do not receive utility-reported reliability information and do not make it available publicly if they receive it. The 10 states shown in dark-striped shading (Alaska, Arizona, Kentucky, Michigan, Mississippi, South Carolina, South Dakota, Tennessee, West Virginia, and Wyoming) do not currently require utilities to report reliability information. The three states denoted by light-striped shading (Alabama, Arkansas, and Nevada) require utilities to report reliability information but do not make this information publicly available.

As noted previously, Nebraska, shown in white, has no state-regulated utilities.

3.2 Changes in Requirements for Reporting Over Time

In 2004, the National Regulatory Research Institute (NRRI), the research branch of the National Association of Regulatory Utility Commissions (NARUC), surveyed state PUC requirements and practices for utility-reported reliability information. By comparing the findings from the NRRI survey to those from the current work, we can begin to assess changes in state PUC reporting requirements over time.

As summarized in Table 1, NRRI received responses from 42 PUCs. Of these, 25 PUCs had routine reporting requirements for utility reliability information. Our current research finds that, in 2006, 35 PUCs required routine reporting, a net increase of 10 PUCs compared to the NRRI survey.

Table 1. Assessment of State PUC Reporting Requirements Over Time

	PUCs that Indicated Routine Reporting Requirements in 2004 NRRI Survey	PUCs that Confirm Routine Reporting Requirements in LBNL 2006 Study
Yes	25	35
No	17	16
Did Not Respond	9	0

It is important, however, to qualify this apparent increase as follows. A total of 23 PUCs that required routine reporting in 2006 were also found by NRRI to require routine reporting in 2004, while two PUCs that NRRI found required routine reporting no longer require this reporting

[4] Although a state PUC may not require routine reporting, some of these PUCs, in fact, receive reliability performance information from utilities and in some cases made this information available for this study, including Arkansas, Idaho, North Dakota, and New Mexico.

(Arkansas and Idaho). Seven PUCs that required routine reporting in 2006 were not found by NRRI to require routine reporting in 2004. Five PUCs that required routine reporting in 2006 were PUCs that did not respond to the NRRI survey in 2004.

3.3 Reporting Requirements for Metrics and the Definition of Major Events

In Section 4, we discuss the reliability information reported by utilities to state PUCs. That discussion points to important differences in reporting practices that complicate review and assessment of information reported by utilities in different states. In this sub-section, we lay the groundwork for that discussion by reviewing part of the basis for these differences, which is found in the specificity of state requirements regarding the type of reliability information that must be reported and the definition of major events.

3.3.1 Reliability Metrics Reported

The reported reliability metrics do vary among the states that require routine reporting. However, the two most common measures of reliability (SAIDI and SAIFI) are generally consistent across all states (see Figure 3).

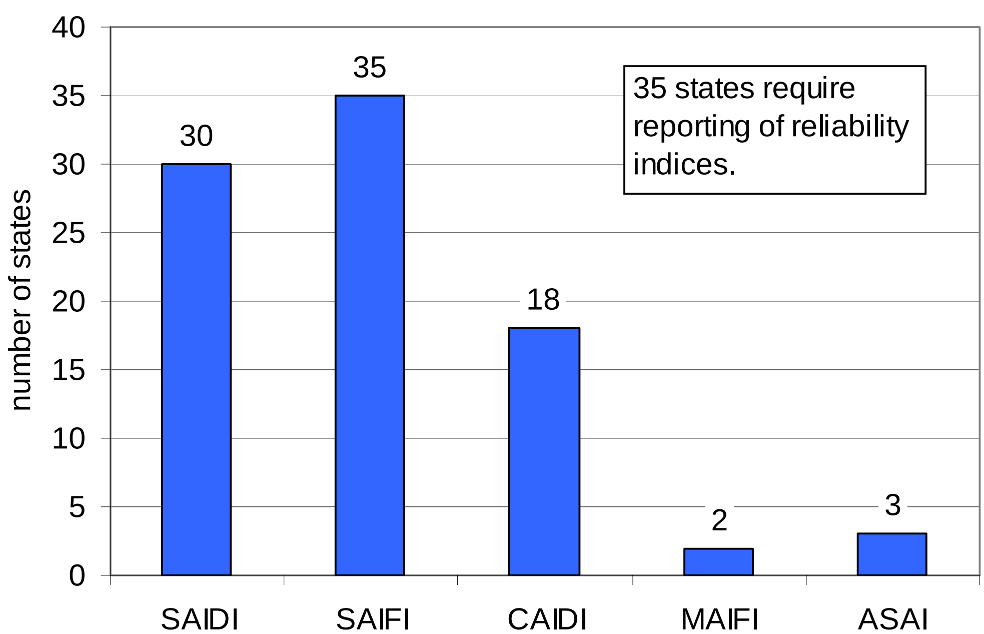


Figure 3. State Reporting Requirements for Reliability Metrics

All 35 states require reporting of SAIFI. Thirty states require reporting of SAIDI and 18 states require reporting of the Customer Average Interruption Duration Index (CAIDI). However, the definitions of SAIDI, SAIFI, and CAIDI are interrelated. SAIDI can be calculated from SAIFI and CAIDI and CAIDI can be calculated from SAIDI and SAIFI (see Appendix A). Therefore, for all intents and purposes, SAIDI and SAIFI are either directly reported or, if SAIDI is not directly reported, it can be derived from SAIFI and CAIDI, which are reported.

In contrast, only two states require reporting of MAIFI and only three states require reporting of the Average System Availability Index (ASAI), an index that can be derived from CAIDI.

3.3.2 Definition of Major Events

Information on reliability is sometimes segmented using the concept of major events. Major events are defined by a variety of criteria to differentiate between routine power interruptions and non-routine or extraordinary power interruptions. In Section 4, we review specific variations in the way major events are defined and assess the impact that segmenting reliability information using these definitions has on reliability metrics. Here, we report the extent to which state requirements determine utility practices for defining major events.

Of the 37 PUCs that made utility-reported reliability information available for our study, 21 said they have adopted a formal definition of a major event. Of these 21, four states (Colorado, Delaware, DC, and Utah) require the use of the IEEE Standard 1366-2003 to define major events using the concept of major event days (see Text Box on page 2). The remaining 17 states use some other definition for a major event. Fifteen states do not formally define major events. We were not able to obtain information from one state about whether it has adopted a formal definition of major events.

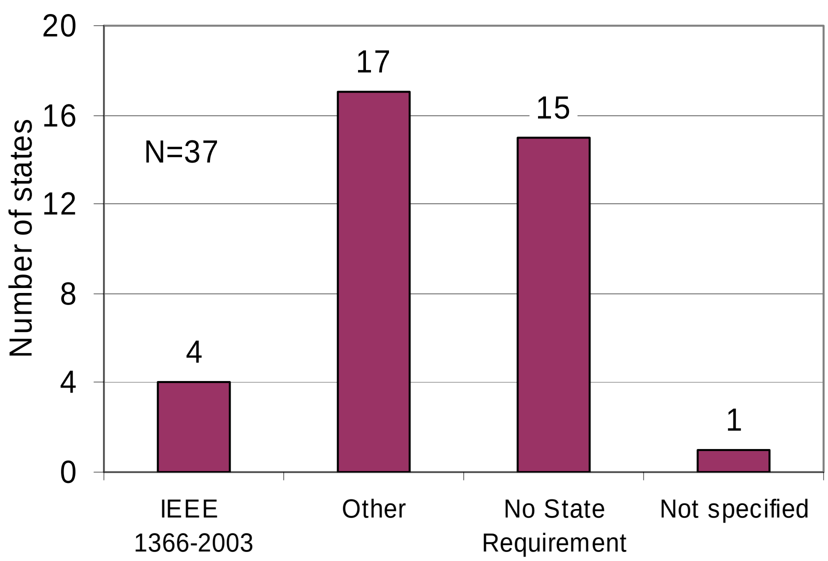


Figure 4. State Reporting Requirements for the Definition of Major Events

4. Review and Assessment of Utility-Reported Reliability Information to State PUCs

We received utility-reported reliability information for 123 utilities from 37 state PUCs representing year 2006. In this section, we present qualitative and quantitative findings and assess utility practices for collecting and reporting reliability information to state PUCs. Our assessment focuses on three reliability metrics, SAIDI, SAIFI, and MAIFI, which, taken together, can be used to comprehensively assess reliability on a national basis (LaCommare and Eto 2004).

We begin by reviewing reliability information aggregated by U.S. Census Division regions (Energy Information Administration 2003). See Figure 5. Although we observe discernable trends in the aggregated information, the process of aggregating made us aware of differences among utility practices for defining and presenting reliability information. Without a better understanding of the impact of these differences on the reported information, it is difficult to ascribe the trends we observe to material differences in reliability among utilities.

Thus, the majority of this section reviews and attempts to quantify the impact of differences in reporting practices on reported reliability metrics. We focus initially on differences in practices for defining sustained interruptions. We then focus on practices regarding the treatment of major events, including the practice of reporting reliability metrics including and not including major events, the definitions of major events, and the effect of adopting IEEE Standard 1366-2003, which provides a standardized, statistically based method of defining major events.

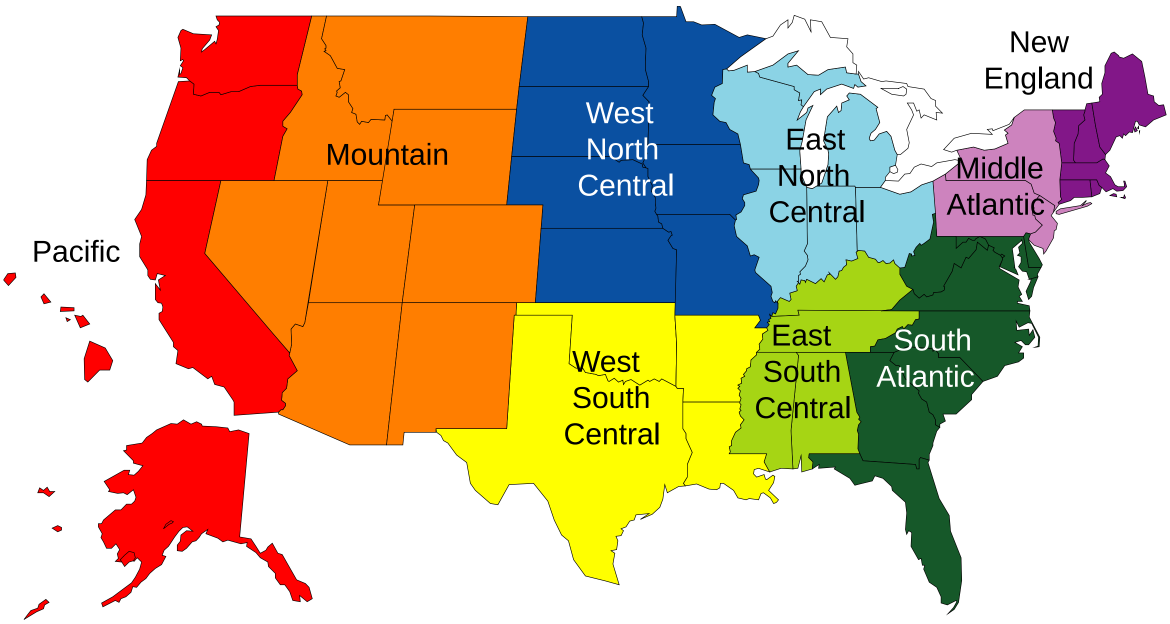


Figure 5. Map of U.S. Census Divisions

4.1 Regional Trends in SAIDI, SAIFI, and MAIFI

The data in Table 2 represent summary statistics (number of observations, simple average, and standard deviation) for the reliability information (SAIDI, SAIFI, and MAIFI) we received aggregated to regions as defined by the nine U.S. Census Divisions. Table 2 also provides two indicators of the representativeness of the information we received for each region: 1) the electricity sales by the utilities for which we have reported information as a percentage of the total electricity sales by all state-regulated investor-owned utilities within that region; and 2) the electricity sales by the utilities for which we have reported information as a percentage of the total electricity sales by all electric utilities (both state-regulated and non-state-regulated) within that region. Information on electricity sales is taken from EIA Form 861 (Energy Information Administration 2006).

As reflected in Table 2, the information we collected accounts for over three-quarters of total electricity sales by state-regulated utilities or nearly 60% of total U.S. electricity sales. However, the representativeness of the information we collected varies by region. For some regions (Middle Atlantic, New England, and Pacific), we received information representing essentially all electricity sales by state-regulated utilities within these regions. For other regions (East North Central, South Atlantic, and West South Central), we received information representing more than 70% of electricity sales by state-regulated investor-owned utilities within these regions. For the remaining regions (Mountain, West North Central, and East South Central) we received information representing progressively lower proportions of electricity. For one region, East South Central, we did not receive information for any of the ten state-regulated utilities within this region.

All 123 utilities reported SAIDI and SAIFI (and/or CAIDI, which along with SAIFI can be used to calculate SAIDI). Only 12 of the 123 utilities reported MAIFI.

In general, one might expect reliability to vary because of regional differences in climate, vegetation, and population. Visual review of the information we collected averaged by region shows greater variation in SAIDI than in SAIFI. A greater than two-to-one difference can be seen in average SAIDI, ranging from a low of 118 minutes in the Mountain region to a high of 498 minutes in East North Central. Variations in average SAIFI are smaller, ranging from a low of 1.22 in Mountain to a high of 1.99 in Pacific. However, despite the ranges observed in average SAIDI and SAIFI, the high standard deviations associated with them indicate that the differences among regions are not statistically significant.

Similarly, the very small number of reported MAIFI values makes it difficult to ascribe a statistical significance to even the wide range of observed variation in these values. Accordingly, the remainder of this review will largely focus on SAIDI and SAIFI.

The significance of differences among the summary statistics emerging from this initial review is further diminished by the recognition that utility practices in collecting and reporting these reliability metrics vary.

Table 2. Summary of Utility-Reported SAIDI, SAIFI, and MAIFI by Census Division

Census Division	Sales as Percentage of Total IOU Sales in Region	Sales as Percentage of Total U.S. Sales in Region	SAIDI (minutes)			SAIFI			MAIFI		
			N	Avg	Std Dev	N	Avg	Std Dev	N	Avg	Std Dev
New England	99%	68%	16	198	130	16	1.44	0.62	ND	ND	ND
Middle Atlantic	100%	75%	21	225	188	21	1.28	0.55	ND	ND	ND
East North Central	75%	62%	19	498	895	19	1.46	0.48	ND	ND	ND
West North Central	57%	35%	12	166	202	12	1.31	0.68	2	5.11	5.03
South Atlantic	71%	53%	18	320	200	18	1.86	0.62	4	11.1	2.16
East South Central	0%	0%	ND	ND	ND	ND	ND	ND	ND	ND	ND
West South Central	88%	30%	18	134	56	18	1.38	0.46	ND	ND	ND
Mountain	35%	27%	7	118	58	7	1.22	0.54	ND	ND	ND
Pacific	99%	62%	12	296	214	12	1.99	1.21	6	3.40	2.35
U.S.	77%	58%	123	244	243	123	1.49	0.64	12	6.55	3.18

Note: N = number of reported values; Avg = average; Std Dev = standard deviation; ND = no data

4.2 Utility Practices for Defining Sustained Interruptions

Taken together, SAIDI, SAIFI, and MAIFI provide a comprehensive measure of electricity reliability because they capture the key features of the range of power interruptions experienced by electricity consumers. The SAIDI and SAIFI indices measure the duration and frequency, respectively, of sustained interruptions, while MAIFI measures the frequency of momentary interruptions. The definitions for sustained and momentary interruptions are interdependent, whereby a sustained interruption is any interruption that is not classified as a momentary event.

Although these definitions ensure that all power interruptions are classified as either sustained or momentary, utility definitions of whether an interruption is sustained or momentary vary. Figure 6 shows the different definitions for sustained interruptions that we found in the utility-reported reliability information we received.

Consistent with IEEE Standard 1366-2003 (and prior versions of this standard), the most common definition of a sustained interruption is one that is greater than or equal to 5 minutes in duration. Still, a fair number of utilities use other definitions. For example, nearly a quarter of the utilities (28) use a shorter duration (one or two minutes) for sustained interruptions.

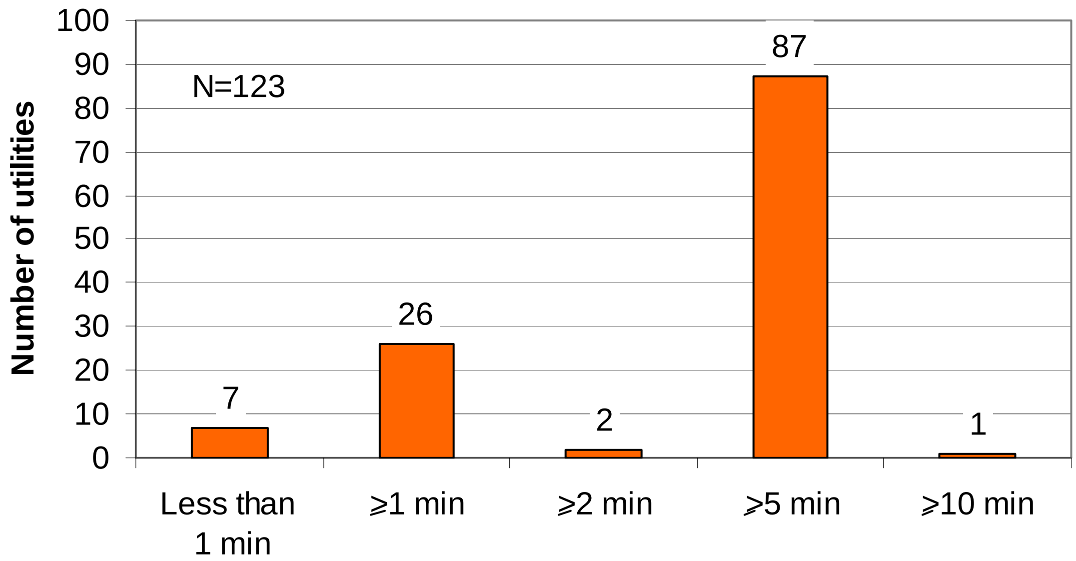


Figure 6. Utility Practices for Defining Sustained Interruptions

First principles suggests that differences in utility practices regarding the minimum duration used to classify an interruption as sustained would tend to affect SAIFI more than they would affect SAIDI. We examined this suggestion by comparing the reliability metrics reported by the two largest subsets of utilities grouped according the definitions they used to specific the duration of a sustained interruption.

Table 3 compares SAIDI and SAIFI (both not including major events) for the 76 utilities that define a sustained interruption as lasting 5 minutes or longer to the 19 utilities that define a sustained interruptions as lasting 1 minute or longer. We find that these differences in definitions do not represent, by themselves, statistically significant differences in reported SAIDI or SAIFI between these two groups.

Table 3. Summary of Utility-Reported SAIDI and SAIFI With Major Events Not Included for Utilities Using 1-Minute and 5-Minute Definitions for Sustained Interruptions

	SAIDI		SAIFI	
	5 min without major events included	1 min without major events included	5 min without major events included	1 min without major events included
Average	165	143	1.3	1.4
Std Dev	97	63	0.5	0.7
Median	145	151	1.3	1.3
N	78	19	78	19

4.3 The Origins of MAIFI and the Significance of Momentary Interruptions

In discussing with industry experts utility definitions of sustained and momentary interruptions, we find that momentary interruptions are a comparatively recent concern for utilities and that practices for recording them are not widespread. The underlying factors include technical features now inherent in the design and operation of modern utility electricity delivery systems, increased sensitivity of certain end use devices to momentary interruptions, and the difficulty of reliably tracking momentary interruptions.[5]

The ability of an electricity delivery system to ensure reliability, as measured by the continuity of electricity service, depends on both the design and operation of the system, as well as the external conditions (e.g., weather) in which the system is expected to operate. A key technical element of modern electricity delivery systems is automatic devices that protect systems from damage during a disturbance and then, following the disturbance, restore electricity service. These devices sense and isolate portions of a system automatically to prevent a disturbance (e.g., a lightning strike) from damaging the system. In so doing, the devices interrupt service to the portions of the system that are "downstream" of the disturbance. Because the majority of disturbances are momentary, the devices are also designed to reconnect the isolated portions of the systems (i.e., reclose the opened circuit) automatically after a pre-determined delay. If the disturbance has passed, the reconnection will be successful and service will be restored. If the disturbance has not passed, the device will again automatically re-isolate that portion of the system. This sequence may be repeated more than once. At some point, usually under one minute, the devices, following a pre-determined rule, will cease attempting to reconnect the isolated portion of the system. At this point, the utility must take additional steps to restore service to the isolated portion of the system.

The number of reconnection attempts that a device is allowed to make and the time-delay between attempts are choices specified by the utility when it selects the device. The number of customers that may be affected by the operation of this device is also determined by the utility in designing its electricity delivery system and locating these devices within the system. These choices are guided by common industry practices as well as by individual utility design philosophies.

The key point here is that the momentary interruption of electricity service associated with operation of these devices is an intentional feature of the design and safe operation of the majority of modern electricity delivery systems. Prior to the introduction of these devices on distribution circuits in the 1940's, all interruptions of electric service were sustained interruptions because utility efforts to restore service required manual actions by utility personnel.

The introduction of these devices enabled automatic, rather than time-consuming manual, restoration of electric service. As a result, the frequency and duration of sustained interruptions decreased.

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[5] This discussion has been informed by comments received from members of the IEEE Distribution Reliability Working Group on an early draft of this report.

Public interest in momentary interruptions began in the 1970's when digital, rather than analog, electricity consuming devices were introduced to consumers. Early versions of these devices lacked a back-up source of power and were, therefore, especially vulnerable to momentary interruptions. Within the residential sector, digital clocks would start blinking and need to be reset following a momentary interruption. Within the commercial and industrial sector, machinery and processes controlled by programmable logic chips would stop operating following a momentary interruption (or a power quality event, such as a voltage sag event).

In other words, momentary interruptions, which resulted intentionally from utility efforts to reduce sustained interruptions, were now being recognized as causing new reliability problems for certain types of electricity consuming devices and processes. Consequently, there was movement toward formally defining and recording momentary interruptions.

Differences of opinion, however, exist regarding utility versus customer responsibilities for addressing the impacts of momentary interruptions and, therefore, of the importance of tracking momentary interruptions. Some experts believe that the most cost-effective way to reduce customer impacts from momentary interruptions (and power quality events) is to reduce the vulnerability of the individual electricity consuming devices or processes that are affected, rather than undertake measures on the utility-side of the meter to reduce the frequency of momentary interruptions.

Finally, it is important to bear in mind that, until recently, the methods for recording the duration of interruptions, both sustained and momentary, have been largely manual. For sustained interruptions, rounding to the nearest minute, and starting with a minimum duration of say 5 or 10 (or even 30) minutes was common practice. For momentary interruptions, it is not usually possible, unless utility personnel happen to be present at the time to record when an automatic restoration device activates. Only with the advent of automated outage management and recording equipment has more precise tracking of the duration of interruptions (both sustained and momentary) and numbers of customers affected been possible.

Together, these factors help explain why so few utilities report MAIFI and why there are differences among utilities in defining the transition between momentary and sustained interruptions. Momentary interruptions are a feature of the intended operation of modern electricity delivery systems and there are differences of opinion as to whether they should be tracked in the same manner as sustained interruptions. Moreover, it is difficult to record momentary interruptions accurately without expensive monitoring equipment.

4.4 Utility Practices for Segmenting Reliability Information Based on Major Events

As noted in Section 3, major events are defined by a variety of criteria that differentiate between routine power interruptions and non-routine or extraordinary power interruptions. Utility practices vary regarding the treatment of major events in reporting reliability metrics, including SAIDI and SAIFI. Some utilities report reliability metrics with major events included; others report these metrics with major events not included. And some utilities report the metrics both with major events included and not included.

Table 2 was developed by averaging a single SAIDI and SAIFI value from each utility for which we had reported information. We sought first to include values reported with major events included. However, when a utility reported only values with major events not included, we used that value. Table 4 gives a more complete picture of all the reliability information we received as it presents summary statistics on SAIDI and SAIFI both with major events included and not included.

Table 4 indicates that we received more SAIDI and SAIFI values without major events included than with major events included. The averages of SAIDI and SAIFI with major events are generally larger than those with major events not included and the differences can be significant. For example, the average SAIDI with major events is more than twice the average SAIDI with major events not included for the East North Central region.

Higher averages for figures that include major events would appear to be a predictable result; i.e., if some events are not included, then the resulting values of SAIDI and SAIFI should be lower. However, this is not always the case. The average SAIDI with major events not included is higher than the average SAIDI with major events included for the West South Central region.

Table 4. Summary of Utility-Reported SAIDI and SAIFI With Major Events Included and Not Included

	SAIDI								SAIFI							
Census Division	With Major Events Included				With Major Events Not Included				With Major Events Included				With Major Events Not Included			
	N	Avg	Std Dev	Wgt Avg	N	Avg	Std Dev	Wgt Avg	N	Avg	Std Dev	Wgt Avg	N	Avg	Std Dev	Wgt Avg
New England	7	260	196	312	17	148	88	147	7	1.40	0.66	1.42	17	1.26	0.61	1.29
Middle Atlantic	7	399	239	566	21	156	97	214	7	1.54	0.73	1.03	21	1.13	0.44	0.96
East North Central	19	498	895	424	15	150	60	133	19	1.46	0.48	1.46	15	1.24	0.19	1.22
West North Central	6	256	263	131	12	107	84	92	6	1.58	0.87	1.17	12	1.25	0.64	1.06
South Atlantic	15	350	207	254	18	212	111	143	15	1.94	0.65	1.76	18	1.50	0.40	1.39
East South Central	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND
West South Central	10	114	47	115	18	126	58	130	10	1.24	0.50	1.16	18	1.33	0.46	1.32
Mountain	5	126	68	139	5	112	60	117	5	1.22	0.61	1.35	5	1.20	0.58	1.47
Pacific	9	332	238	245	12	156	71	128	9	1.93	1.21	1.34	12	1.59	0.95	1.08
U.S.	78	292	269	234	118	146	79	144	78	1.54	0.71	1.02	118	1.31	0.53	1.13

Note: N = number of reported values; Avg = average; Std Dev = standard deviation; Wgt Avg = weighted average; ND = no data

Although the number of utility reports contributing to these averages is identical, comparison between Table 4 and Table 2 confirms that different utilities comprise each of these averages.

Although there is some overlap between the utilities whose reported information contributes to both averages (i.e., utilities that report SAIDI and SAIFI both with major events included and not included), many reported values are also included from utilities that reported SAIDI and SAIFI either with major events included or with major events not included (but not both).

The above review makes clear that treatment of major events in SAIDI and SAIFI must be taken into account when reviewing utility-reported reliability information. We now focus on direct examination of the significance of differences in practices for reporting SAIDI and SAIFI.

4.5 Reporting SAIDI and SAIFI with Major Events Included and Not Included

As discussed above, it is difficult to assess the effect of reporting SAIDI and SAIFI with major events included and not included when the utility reports that represent this information do not all include both pieces of information. Fortunately, 71 of the 123 SAIDI and SAIFI values we received were reported both with and without major events included. By focusing on these 71 reports, we can directly examine the effect of this difference in reporting practices.

Figures 7 and 8 present the distributions of the reported values and summary statistics for these 71 utility reports of SAIDI and SAIFI, respectively.

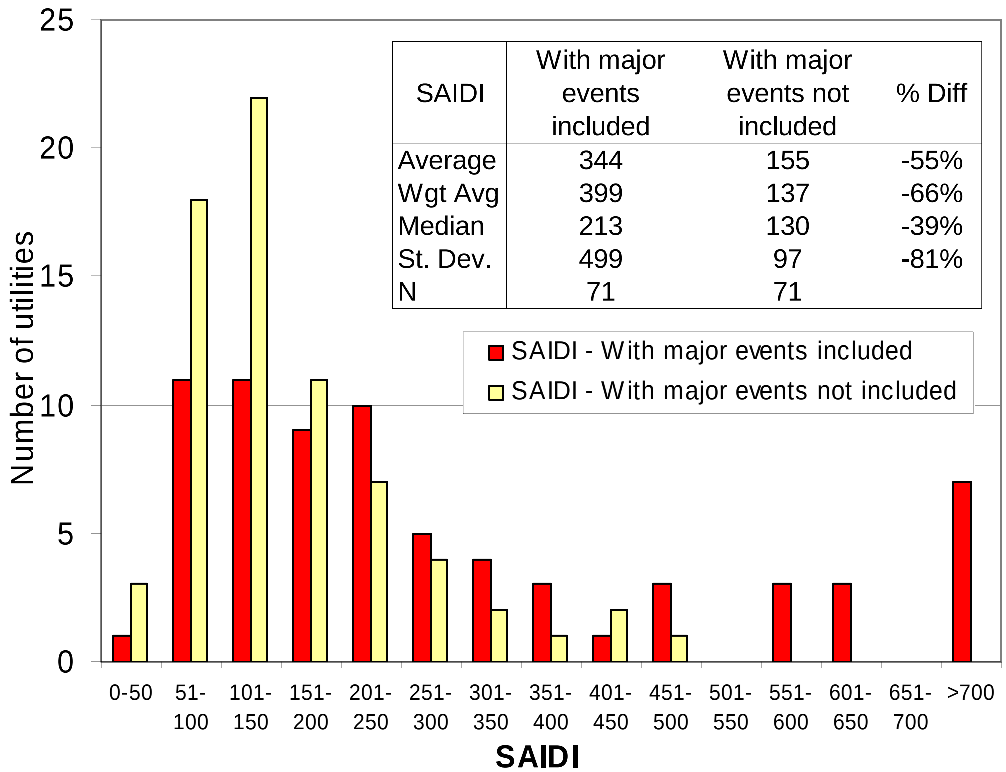
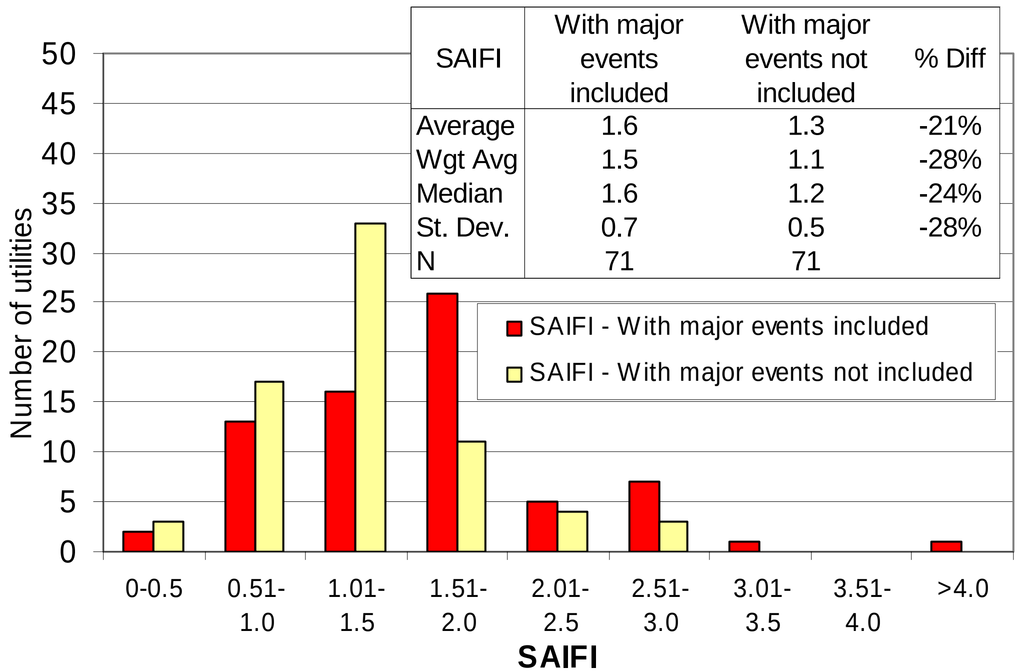


Figure 7. Distribution of and Summary Statistics for SAIDI Reported With Major Events Included and Not Included



SAIFI	With major events included	With major events not included	% Diff
Average	1.6	1.3	-21%
Wgt Avg	1.5	1.1	-28%
Median	1.6	1.2	-24%
St. Dev.	0.7	0.5	-28%
N	71	71	

Figure 8. Distribution of and Summary Statistics for SAIFI Reported With Major Events Included and Not Included

The effect of reporting with major events not included is clearly visible in the shift of the distributions for SAIDI and SAIFI when major events are included. The average SAIDI decreases by more than half (-55%) and the standard deviation is reduced by more than three quarters (-81%). The average, median, and standard deviation for SAIFI decrease by about one-quarter (-21%, -24%, and -28%, respectively).

4.6 Utility Practices for Defining Major Events

In reviewing how reporting with and without major events included affects SAIDI and SAIFI, we also find that utility practices vary regarding how major events are defined. As reported in Section 3, although IEEE Standard 1366-2003 provides a standardized, statistically based method for distinguishing among reliability events using the concept of Major Event Days (see Appendix A), this standard has only been formally adopted by four state PUCs. Fifteen state PUCs require use of a different definition for major events and an additional 16 state PUCs, which require routine reporting, have no formal requirements for the definition of major events.

With the exception of IEEE Standard 1366-2003, we find that the factors used to segment major events can be categorized according to the following characteristics:

- Whether the interruption was *planned* or *unplanned*. For example, an unplanned interruption might include one caused by a severe storm, earthquake, tornado, or high wind, while a planned interruption might refer to scheduled maintenance;
- The magnitude of the interruption, as measured by either the amount of *load* or number of *customers* affected; and

- The duration of the interruption, e.g., 24 hours or more.

Typically, more than one characteristic is used. Here are three examples drawn from actual definitions of major events in the utility-reported information we received for this study. In the first two examples, major events are called *excludable events.*

Example 1:

> "An excludable event can be caused by: (a) planned service interruption, (b) a storm named by the National Hurricane Center, (c) a tornado recorded by the National Weather Service, (d) ice on lines, (e) a planned load management event, (f) any electric generation or transmission event not governed by subsections rules, or (g) an extreme weather or fire event causing activation of the county emergency operation center."

In this example, the major event definition includes both planned interruptions (planned service interruptions and planned load management events) and unplanned interruptions caused by various types of severe weather or fires.

Example 2:

> "Excludable events are 'abnormal' situations such as hurricanes, tsunamis, earthquakes, floods, catastrophic equipment failures, and a single equipment outage that cascades into a loss of load that is greater than 10% of the system peak load."

In this example, the major event definition includes only unplanned interruptions ("abnormal" situations) but also considers the magnitude of the event, specifying a threshold for the amount of load that must be interrupted (10%).

Example 3:

> "A 'major event' is defined as any day (24-hour period) where 10% of the total company customer base experiences an interruption. The 'major event' ends when the total customers interrupted drops below 100."

In this example, the major event does not distinguish between planned and unplanned interruptions, but it does specify a load-based criterion (10% of customers).

Figure 9 summarizes our efforts to classify major event definitions using the above characteristics. Because more than one characteristic is typically used to define a major event, the sum of the factors used to define major events is greater than the number of utilities for which we received information. We find that the majority of major event definitions focus only on unplanned interruptions and rely on the number of customers interrupted to establish a threshold for the magnitude of the event. A large number of definitions also include a measure of the duration of the interruption.

Notably, 14 utility reports indicate that IEEE Standard 1366-2003 is used to segment the data using the concept of Major Event Days. We turn to a direct examination of the effect of reporting using this standard in the next sub-section.

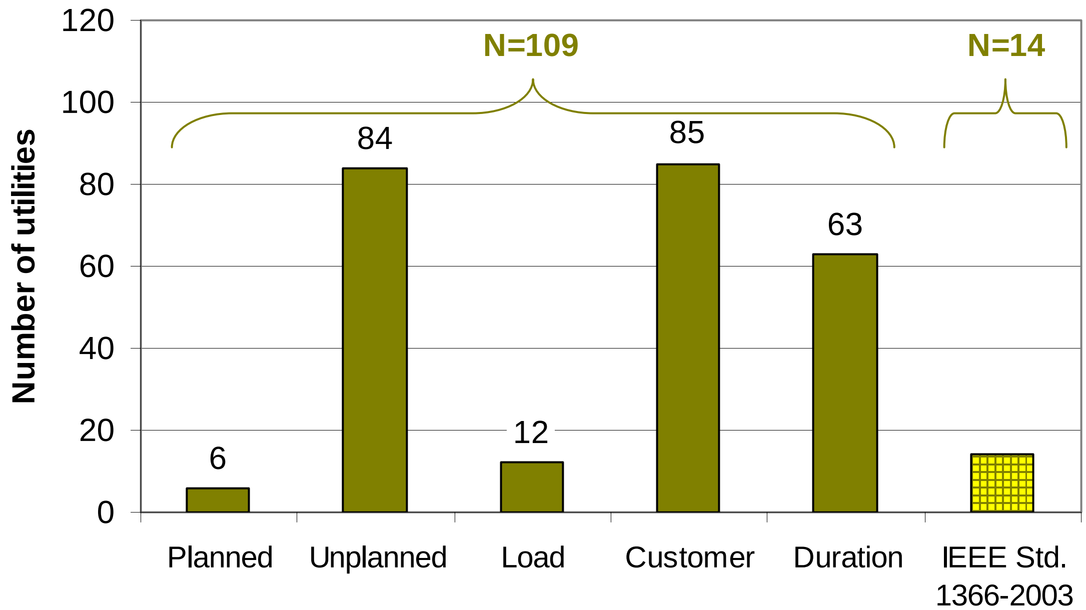


Figure 9. Assessment of Common Characteristics Used by Utilities to Define Major Events

4.7 Using IEEE Standard 1366-2003 to Segment SAIDI and SAIFI with Major Event Days

IEEE Standard 1366-2003 is a voluntary industry effort to develop standard definitions and procedures for measuring and reporting reliability performance. Adoption of such a standardized approach would greatly simplify review of this information and improve assessment of utility-reported reliability information because it would eliminate differences in the reported information that are due solely to differences in reporting practices.

To date, however, adoption of the standard is in its infancy. As noted in Section 3, only four states formally require utility reporting using the standard and, among the 123 utilities for which we have information, 14 utilities reported reliability information using the standard.

Among these 14 utility reports, 9 give sufficient information to enable a preliminary assessment of the impact of using the new standard. That is, these 9 reported SAIDI and SAIFI calculated using both the concept of Major Event Days embodied in the standard as well using the former definition for major events to segment the reliability information.

Figure 10 shows the differences in the reported SAIDI and SAIFI that result from application of the two different procedures for segmenting the information. The differences are expressed as a percentage difference between the two values that result from use of each procedure.

From this preliminary examination, we find that there is no discernable bias introduced by use of the segmentation procedure embodied in the new IEEE standard compared to former practices for segmenting the information. That is, in several instances use of the procedure in the new standard leads to higher SAIDI and SAIFI values; in other instances it leads to lower values. Moreover, in this limited sample, the number of higher and lower values is roughly equal.

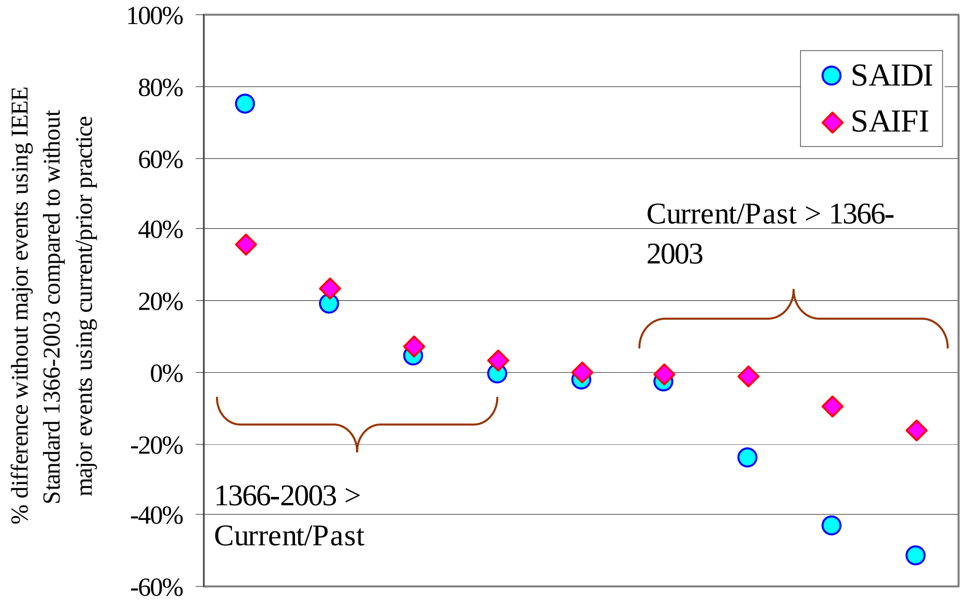


Figure 10. Comparison of SAIDI and SAIFI Without Major Events for 9 Utilities that Reported Using both IEEE Standard 1366-2003 and Current/Prior Practice for Segmenting Major Events

5. Comparison of Reliability Information Reported to State PUCs and to National Bodies

Both DOE and NERC require reporting of major electricity system incidents and disturbance events. Reporting to these national bodies is now mandatory, required in near-real time, and includes incidents that sometimes result in no loss of electric service to customers.[6] The principle purpose of this form of reporting to national bodies is to provide information on major (i.e., very large) electricity system emergencies that may require immediate responses by industry or government to ensure public health and safety. Thus, there are fundamental and important differences between reports made to these national bodies and those made to state PUCs. With few exceptions, the same information is reported to both DOE and NERC at the same time.

Nevertheless, some of the incidents and disturbances reported to these national bodies are ones in which customers lose electric service. In this respect, despite fundamental differences in their purpose and scope, reported loss of electric service to these national bodies is similar to the utility-reported reliability information we collected from state PUCs. In this section, we report initial findings from our efforts to compare these two sources of information on power interruptions.

5.1 Department of Energy Form OE-417

DOE requires reporting of major electricity system incidents and disturbances. The information is reported via the Office of Electricity Delivery and Energy Reliability (OE) Form 417, commonly referred to as OE-417 (Department of Energy 2006). An initial notification is due to DOE within 60 minutes of the system disruption, followed by a detailed final report within 48 hours. The criteria for filing a report are as follows.

Form OE-417 must be submitted to the DOE Operations Center within one hour if any one of the following criteria is met:

1. Actual physical attack that causes major interruptions or impacts to critical infrastructure facilities or to operations;
2. Actual cyber or communications attack that causes major interruptions of electrical system operations;
3. Complete operational failure or shut-down of the transmission and/or distribution electrical system;
4. Electrical System Separation (islanding) where part(s) of a power grid remains operational in an otherwise blacked out area or within the partial failure of an integrated electrical system;
5. Uncontrolled loss of 300 Megawatts (MW) or more of firm system loads for more than 15 minutes from a single incident;
6. Load shedding of 100 MW or more implemented under emergency operational policy
7. System-wide voltage reductions of 3 percent or more; or

[6] Reporting to NERC became mandatory in June, 2007. Prior to June 2007, including the period analyzed in this section, reporting to NERC was encouraged, but voluntary.

8. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.

Form OE-417 must be submitted to the DOE Operations Center within six hours if one of the following applies and none of the eight categories above apply:

9. Suspected physical attacks that could impact electric power system adequacy or reliability or vandalism which targets components of any security systems;
10. Suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability;
11. Loss of electric service to more than 50,000 customers for one hour or more; or
12. Fuel supply emergencies that could impact electric power system adequacy or reliability.

The information received by DOE on Schedule 1 is publicly available. The information collected on OE-417 includes the number of customers affected, demand involved, type and cause of incident, and the date and time the incident began and ended. For this analysis, we downloaded the information on the 91 events reported in year 2006 that involved customer interruptions.

5.2 North American Electric Reliability Corporation Disturbance Analysis Working Group Database

NERC standards, which became mandatory in June 2007, require reporting of major electricity system emergencies (North American Electric Reliability Corporation (NERC) 2006). When utilities send OE-417 to DOE, they also send the form to the Regional Reliability Organization and NERC under Standard EOP-004-1.

The requirements for submitting a report to NERC are contained in Standard EOP-004-1, Attachment 1 as follows:

1. Loss of a bulk power transmission component that significantly affects the integrity of the interconnection system operation. Generally, a disturbance report will be required if the event results in actions such as:
    a. Modification of operating procedures.
    b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
    c. Identification of valuable lessons learned.
    d. Identification of non-compliance with NERC standards or policies.
    e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
    f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. Occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity – 2,000 MW or more in the Eastern or Western Interconnection and 1,000 MW or more in the Electric Reliability Council of Texas (ERCOT) Interconnection.
4. Equipment failures/system operational actions, which result in the loss of firm system demand for more than 15 minutes, as described below:

    a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
    b. All other entities are required to report all losses of firm demand totaling more than 200 MW or 50% of the total number of customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.
6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
    a. Sustained voltage excursions equal to or greater than 10%, or
    b. Major damage to power system components, or
    c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require system operator intervention, which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.
7. An Interconnection Reliability Operating Limit violation as required in reliability standard TOP-007.
8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

NERC compiles the filed information in a database that is maintained by DAWG. The DAWG database contains a summary of the disturbance, including the date, region, associated utilities, type of event, MW lost, number of customers affected, and cause. The information contained in the DAWG database is similar to information reported on OE-417, but contains additional information on the disturbance and actions taken.

The information in the DAWG database is publicly available. We obtained information for a total of 52 events in 2006 involving incidents where customers were affected. Prior to June 2007, filing information with NERC on major system emergencies was voluntary. Consequently, there may be more total events listed in OE-417 than are listed in the DAWG database for 2006.[7]

5.3 Comparison of Reported Reliability Information

We compared the interruptions reported to state PUCs and to national bodies to examine the relationship between the reliability information reported by utilities to each of these entities. Reliability information reported to national bodies is restricted to significant events involving large numbers of customers (as defined by the reporting criteria that trigger the filing requirement). Reliability information reported to state PUCs is inclusive and, in principle, includes any and all events affecting customers, regardless of the number of customers affected.[8]

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[7] Utility practices vary regarding the treatment of interruptions, which are large enough to warrant immediate reporting to national bodies, with respect to inclusion of these interruptions in the routine reports to PUCs, which we review in this report. Most utilities include information on all interruptions in their calculation of SAIDI and SAIFI. Some utilities, however, appear to exclude information on these large interruptions from their calculation of SAIDI and SAIFI.

[8] As noted in the previous footnote, if utility reporting practices exclude events large enough to warrant immediate reporting to national bodies from their SAIDI and SAIFI values, these "bulk-power system" SAIDI and SAIFI values should be considered

Comparing the interruptions reported to national bodies, in aggregate, to the total interruptions recorded by utilities, in aggregate, gives a rough measure of the significance of large interruptions compared to all interruptions.

For this comparison, we calculated a "bulk power system only" SAIDI and SAIFI value from the information contained in the utility reports to DOE and NERC. Calculating a pseudo value like this means we are effectively treating the entire U.S. as a single utility, with each report documenting a single, national-level event recorded on the transmission system.[9]

Expressing utility reliability information reported to DOE and NERC using the definitions for SAIDI and SAIFI, however, requires important additional assumptions beyond that reported to these national bodies. The necessary assumptions we made are reasonable, but they leave ample room for improvement. Hence, the values we calculate should be regarded as very preliminary and rough estimates.

To calculate SAIFI from information reported to DOE and NERC required two assumptions. First, we assumed that each reported event was a distinct event from that which might be reported by another entity. This assumption is incorrect when two or more entities report interruptions stemming from the same initiating cause (e.g., a widespread weather event, such as a major hurricane). Second, we assumed that each reported event represented a single event. This assumption is incorrect when an entity aggregates multiple interruptions over a period of time into a single report (e.g., when multiple interruptions result from multi-day period severe weather events).

To calculate SAIDI from the information reported to DOE and NERC required an assumption on how the reported number of customers affected changed over the reported duration of the interruption. We assumed that all the reported number of customers affected would initially experience the interruption and that the number would decline exponentially over the duration of an interruption. This assumption is reasonable for interruptions that are initiated by a single triggering event followed by a period of sequential restoration of service. This assumption is not appropriate, however, for interruptions that represent multiple interruptions that affect different numbers of customers at different periods of time, such as interruptions resulting from a multi-day period of severe weather.

With these important limiting assumptions in mind, Table 5 reports the SAIDI and SAIFI values we calculated from the information reported to DOE and NERC and compared them to the average SAIDI and SAIFI with major events included reported from our data collected from the PUCs in Table 4. This comparison is intended to provide a first-order estimate of the portion of interruptions experienced by utilities that result from events large enough to be reported to national bodies.

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additive to the local utility SAIDI and SAIFI values. If utility reporting practices include all interruptions, including these large interruptions, then these "bulk-power system" SAIDI and SAIFI values should be considered a portion of (or contributor to) the local utility SAIDI and SAIFI values.

[9] See Hines et al. 2008 for more additional discussion of this approach (Hines et al. 2008).

We find that large interruptions appear to represent a small portion of the total number of interruptions experienced by customers (as shown by SAIFI in Table 5). The SAIDI value calculated from the information reported to national bodies suggests that events large enough to warrant reporting to national bodies accounts for a significant amount of the interruptions experienced by utility customers. For example, the SAIDI value calculated from the information reported to DOE suggests that more than half of the customers affected by the total duration of interruptions are accounted for by the large events that must be reported to DOE.

Table 5. Comparison of Year 2006 Reliability Information on Major Electricity System Events to Reliability Information on All Events

	SAIFI	SAIDI
LBNL estimate derived from DOE OE-417	0.10	164
LBNL estimate derived from NERC DAWG	0.07	110
Average of 78 utilities whose reports included major events	1.54	292

These findings, however, are preliminary. They depend on a number of important assumptions that cannot be resolved solely on the basis of information that has been reported to these national bodies. Moreover, in order to provide a reasonable basis for this comparison, we have focused on the 80 utilities that report SAIDI and SAIFI with major events included. Obviously, based on these reports alone, we cannot generalize that the reliability information reported by these 80 utilities are representative of the other 43 utilities we received information on, or of the utilities representing roughly 40% of U.S. electricity sales we have no reliability information.

Nevertheless, to a first approximation, this comparison does support the contention, which is widespread within the utility industry, that the majority of interruptions experienced by customers, at least in number, are local in nature.

5.4 Consistency in Reporting of Large Power Interruptions

In reviewing information regarding major events that was reported by utilities to state PUCs, we identified a second means for comparing this reliability information with what is reported to national bodies.

A large number of utilities (55 of the 123) report information on each individual major event along with SAIDI and SAIFI calculated with major events included or not included. The information reported on each major event to state PUCs is similar to the information reported to national bodies in that it includes the date, time, location, and sometimes the number of customers affected and duration of the event.

Because events that might qualify as major events for the purpose of isolating an individual utility's SAIDI and SAIFI are the largest events experienced by that utility, we expected that some of these events would also qualify for reporting the national bodies. Thus, we attempted to match the information on individual major events reported to state PUCs to the information on individual events reported to national bodies. We first sought to match events according to the reporting utility, date, and time of the interruption. We then sought to compare the number of customers affected. Although this comparison is incomplete, it provides preliminary insight into the consistency of information reported to state PUCs and these national bodies.

For a number of reasons, we expected this matching to yield low results. First, as noted in footnote 7, some utilities exclude events reported to national bodies from major events that are listed individually in reports to state PUCs. Second, reports to national bodies are made by utilities that do not report reliability information to state PUCs (either because utilities are not state regulated, or the state does not have a reporting requirement). Third, the events that meet criteria for reporting to national bodies may not meet the criteria for treatment as major events for state PUC reporting purposes. Fourth, we do not have a census of major events that are recorded by all utilities that also provide reliability information to state PUCs; we have lists of major events for only 55 of the 123 such utilities.

In matching the year 2006 events reported to DOE on Form OE-417 to events reported to state PUCs, we found matches for 24 events based on date, time, and location. Three of these matches were dropped from further review because the entity reporting to OE was not the same entity that reported to the state PUC. An additional 13 matches were dropped from further review because the information reported to state the PUC did not include the number of affected customers.

The percentage difference in the number of affected customers reported to DOE compared to that reported to the state PUC for the remaining eight events is shown in Figure 11. A negative percentage means that the number of affected customers reported to the state PUC is less than the number reported to DOE; a positive percentage means that the number reported to the state PUC is greater than that reported to DOE.

Figure 11 shows that, for this small number of matched events, there are sometimes very large differences. Reports for more than half of the events differ by more than 20%. For the same event, reports to state PUCs appear to indicate more customers are affected compared to reports to national bodies.

In matching events reported to NERC in 2006 with those reported to PUCs, we found matches for 16 of these events based on date, time, and location. Six of these matches were dropped from further review because the entity reporting to NERC was not the same entity that reported to the state PUC. An additional two matches were dropped from further review because the information reported to state PUCs did not include the number of affected customers. Interestingly, the remaining eight matched events using the NERC DAWG information were not the same events matched previously using the DOE OE-417 information.

The percentage difference in the number of affected customers reported to NERC compared to the number reported to the state PUC for the remaining eight events are shown in Figure 12. A negative percentage means that the number of affected customers reported to the state PUC is less than the number reported to NERC; a positive percentage means that the number reported to the state PUC is greater than that reported to NERC.

Figure 12 shows, as did Figure 11, some very large differences. Reports for more than half of the events differ by more than 20%. Here, the tendency of state PUCs to indicate more customers are affected compared to reports to national bodies is even greater than in the previous comparison.

It is difficult to draw definitive conclusions from this initial assessment of reliability information reported to national bodies compared to that reported to state PUCs. Some of the reasons we expected to find such few matches have already been listed. A final consideration is that reporting to national bodies occurs in near real-time. Both DOE and NERC require immediate notification and preliminary information within 24 hours of an event, with a final filing within 48 hours for DOE and within 60 days for NERC. Reliability information reported to state PUCs typically takes the form of an annual summary, provided sometime after the end of a given reporting period.

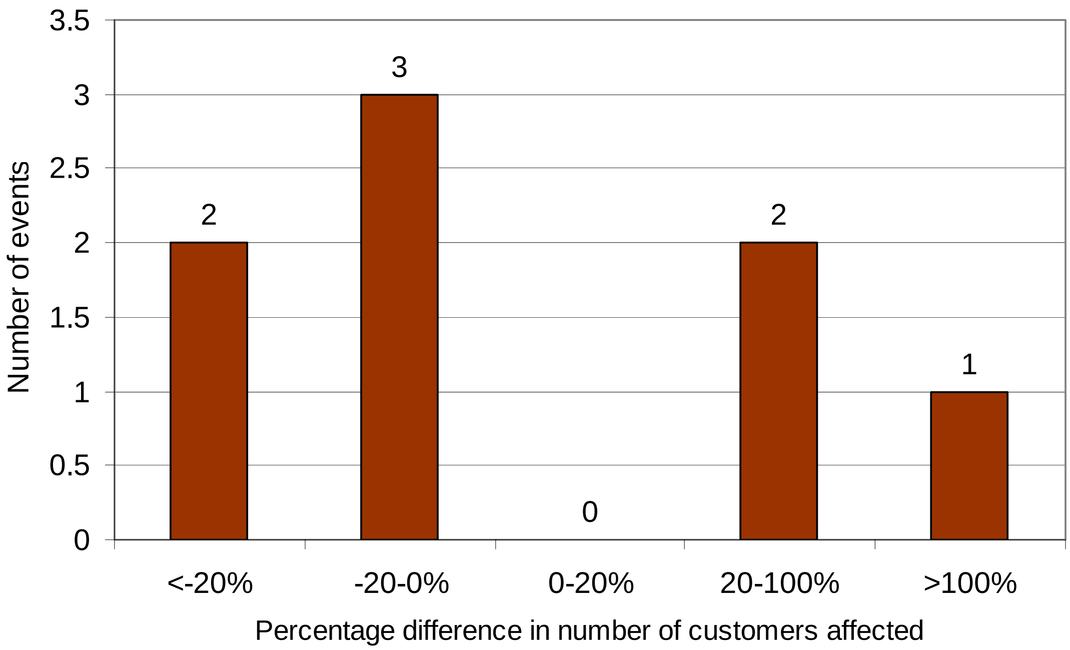

Figure 11. The Difference Between the Number of Customers Affected, as Reported on OE Form 417, and as Reported to State PUCs for Eight Major Events in 2006

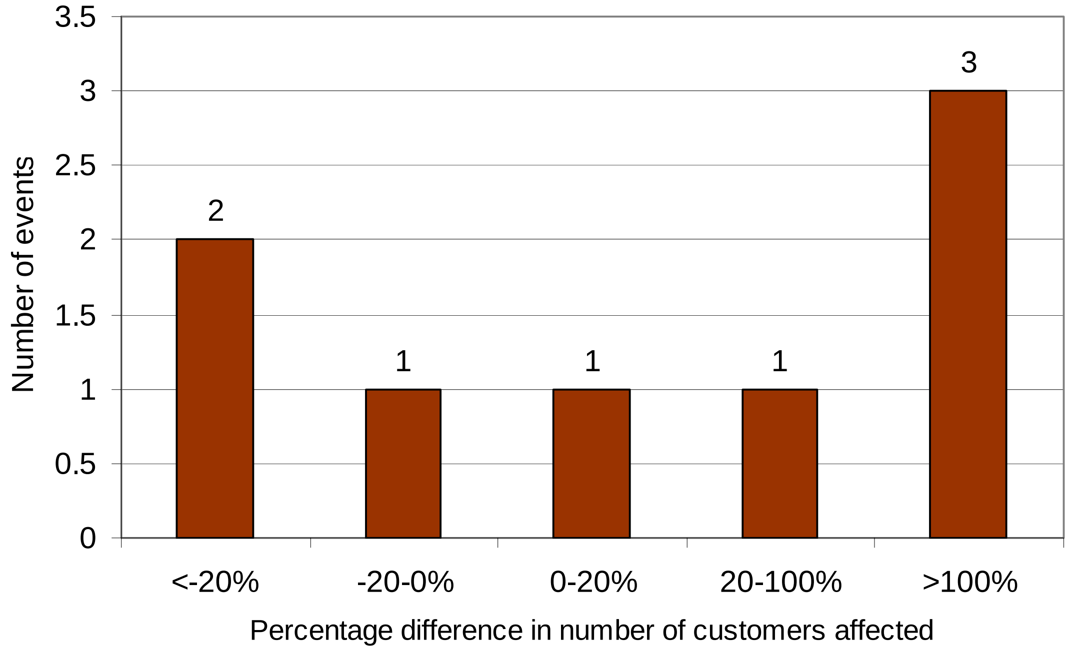

Figure 12. The Difference Between the Number of Customers Affected, as Reported to NERC, and as Reported to State PUCs for Eight Major Events in 2006

6. Summary of Findings and Conclusions

Our findings regarding state PUC practices and rules on reliability information reported by utilities are summarized as follows:

- Thirty-five state PUCs, including DC, require routine reporting of reliability event information. This is a net increase of 10 state PUCs over the number reported in a similar survey conducted by the NRRI in 2004.
- These 35 PUCs require annual reporting of SAIDI and SAIFI and/or CAIDI, which, along with SAIFI, can be used to derive SAIDI. Only two state PUCs require reporting of MAIFI.
- Twenty-one PUCs have reporting requirements that formally define major events. Of these 21, four require reporting following the IEEE Standard 1366-2003, IEEE Guide for Electric Power Distribution Reliability Indices, which introduces a consistent means for defining major events using the concept of "major event days."
- An additional four PUCs receive reliability information from utilities, though not as a result of a formal reporting requirement.
- Thirty-seven state PUCs, including DC, make publicly available or summarize in publicly available documents the reliability information they collect from utilities.

Our findings regarding utility practices for collecting and reporting reliability information to state PUCs are summarized as follows:

- All utilities reported SAIDI and SAIFI (and/or CAIDI). Only 12 of the 123 utilities reported MAIFI.
- Summary statistics for reported SAIDI, SAIFI, and MAIFI exhibit observable though not statistically significant variations across census regions.
- The definition of and practices for recording sustained and momentary interruptions have evolved over time leading to inconsistencies among utilities.
- Differences in the definition of a sustained interruption do not appear to affect SAIDI or SAIFI in a statistically significant manner.
- Utilities define major events as a means for distinguishing between utility performance in planning for and responding to routine interruptions versus that for non-routine or extraordinary interruptions.
- The definition of a major event is not consistent among the majority of utilities.
- IEEE Standard 1366-2003 introduces a consistent means for defining major events using the concept of "major event days."
- Some utilities report SAIDI and SAIFI both including and not including major events; other utilities only report SAIDI and SAIFI not including major events.
- When major events are not included, SAIDI is lowered relatively more than SAIFI compared to when major events are included.
- Many utilities report descriptive information on each major event
- Use of IEEE Standard 1366-2003 does not appear to bias SAIDI or SAIFI values compared to using prior definitions of major events.

We also collected information on bulk power system emergencies reported by utilities in near real-time to national bodies in 2006, including DOE and NERC, and compared aspects of this information to that reported by utilities to state PUCs. Our findings are summarized as follows:

- Information on electricity reliability reported to these two national bodies consists of descriptive information that is reported in near real-time on individual, large events that affect the bulk power system. The reporting takes place in near real-time because an important purpose of the reporting is to notify relevant industry and public bodies of significant power system events that may require immediate response. With few exceptions, the same information is reported to both DOE and NERC at the same time.
- Many, but not all, events reported to these national bodies also cause power interruptions to customers. For these events, the number of customers affected is reported.
- An initial assessment of these events supports the conventional wisdom that the majority of power interruptions experienced by customers are not due to large events that affect the bulk power system; they are due to more localized events that affect only utility distribution systems.
- It is difficult to cross-reference information reported to national bodies on individual large bulk power system events that cause power interruptions, as defined by these national bodies, with information reported to state PUCs on individual major events, as defined by either the PUC or the reporting utility.

From these findings, we draw the following conclusions and recommendations:

- State PUC interest in electricity reliability is growing.
- However, differences in utility reporting practices hamper meaningful comparisons of reliability information reported by utilities to different state PUCs and, therefore, may limit the effectiveness of efforts to measure the effectiveness of efforts to improve reliability.
- Efforts to eliminate differences that are solely due to reporting practices are just beginning. These efforts, which focus on using standard definitions, such as those promoted by IEEE Standard 1366-2003, are promising and should be encouraged.
- Until IEEE Standard 1366-2003 is adopted universally, regulators concerned about the definition and treatment of major events in reporting reliability information should consider requiring reporting of SAIDI and SAIFI both including and not including major events, as well as descriptive information on each major event.
- More work is required to better understand the sources of discrepancies and the importance of seeking greater consistency between reliability information reported to national bodies and that reported to state PUCs.

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Appendix A. IEEE Standard 1366-2003 Reliability Index and Major Event Day Definitions

Utilities record, organize, and report information on reliability events using a variety of metrics. The System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) measure the number and duration, respectively, of sustained interruptions experienced in one year by a customer (IEEE Working Group on System Design 1999). SAIDI and SAIFI are the two metrics most commonly used to express the reliability of electricity service based on duration and frequency of electricity interruptions. The Customer Average Interruption Duration Index (CAIDI) is also commonly reported; it is derived from SAIDI and SAIFI. The Momentary Average Interruption Frequency Index (MAIFI) is less commonly reported. However, MAIFI is important because SAIDI, SAIFI, and MAIFI, taken together, provide a comprehensive measure of electricity reliability, as measured by the duration and frequency of power interruptions.

According to the IEEE Standard 1366-2003 standard, the definitions for these indices are as follows:

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

$$\text{SAIFI} = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

$$\text{MAIFI} = \frac{\sum \text{Total Number of Customer Momentary Interruptions}}{\text{Total Number of Customers Served}}$$

IEEE Standard 1366-2003 defines sustained interruptions as lasting more than five minutes and momentary interruptions as lasting five minutes or less.

IEEE Standard 1366-2003 also provides guidelines for identifying major events using the concepts of Major Event Days (MEDs). This standard introduces a “2.5 beta method” that defines an MED as a day in which the daily system SAIDI exceeds a threshold value, T_{MED} . The T_{MED} threshold value is calculated as follows:

(a) Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.

(b) Only those days that have a SAIDI/Day value will be used to calculate the T_{MED} (do not include days that did not have any interruptions).
(c) Take the natural logarithm (ln) of each daily SAIDI value in the data set
(d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.
(e) Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set
(f) Compute the MED T_{MED}, using the following equation,

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

(g) Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a MED.