

Reliability Surveying - Segmenting For Comparability

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Abstract—This paper deals with utility reliability benchmarking and the various factors that affect IEEE reliability indices as calculated by the various utilities and the need to understand and segment on the basis of those factors.

Index Terms— Reliability, Surveying

- Outage Management Systems
- Circuit Connectivity
- Distribution Automation/SCADA
- Geography
- Outage Definition
- Automated Meter Reading Outage Reporting
- Storm Normalization

I. INTRODUCTION

Utilities and regulators alike have for many years attempted to develop a means for measuring the performance of utilities over time. More recently, as the use of performance-based rates has come into vogue, regulators have looked for ways to benchmark an individual state's utilities against each other as well as against the utility industry in general. Current benchmarking methods have led to some false conclusions due to the fact that they don't take into account the various factors that affect reliability and that differ from utility to utility. These factors are real and present some real challenges to those interested in developing some valid benchmarks. This paper will look at the various factors that are relevant to the benchmarking discussion and need to be taken in to account in any survey or study.

The reliability indices referred herein as those standard indices as defined in the *Full Use Guide For Electric Power Distribution Reliability Indices* IEEE1366-2001.

II. LOOKING AT COMPARABILITY

Utilities and regulators alike have a need for better understanding how utilities compare in the level of reliability offered to customers. However, given the current state of reliability benchmarking, there are a number of problematic issues associated with the standard indices prepared by the individual utilities. These issues prevent any meaningful direct comparisons between indices of different utilities and can lead to incorrect conclusions from the indices when not clearly understood and taken into account. In this paper, the following main factors affecting direct reliability index comparison will be discussed:

A. *The Outage Management System*

What type of Outage Management System (OMS) does the utility employ? Utilities have employed various degrees of automation in the accumulation and storage of outage data. Do customer calls feed directly into the OMS? Are the calls written down and then later entered into an outage database? Are the calls retained on paper where they are counted when the indices are required? Many utilities automated systems track outages through their life cycle; many other systems do not. By their very nature, completely automated systems keep better track of the outage frequency and duration and thereby lead to higher indices than would be experienced by paper systems. For good comparisons, utilities should always be aware of the system capabilities of those other utilities included in the results. Otherwise, what appears to be poor performance on the surface may not be poor at all.

B. *Circuit Connectivity*

While some would include this item in with automation of the OMS, this is really a separate issue. Connectivity refers to the ability of the system to infer outages onto all affected customers, even those who did not notify the utility, from data related to the received calls or the location of the affected device. When a transformer that serves 12 customers fails, but only two customers call, what does the system count, 2 or 12? A utility with complete circuit connectivity takes the 2 calls, knows the transformer serves 10 others, and will record a loss of service to 12 customers. Utilities without circuit connectivity may only count the 2 calls as affected customers. This leads to gross inequities between utilities and quite possibly the largest source of error. Without connectivity throughout the circuit and system, there is simply no way to know the exact number of customers out of service for any given component failure and record the number accordingly. After implementing automated mapping systems with circuit connectivity and

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automated OMS, utilities have been known to experience outage rates more than double previous indices. Any survey, in order to be useful to participants, should require the identification of the level of circuit connectivity employed at the utility.

C. *Distribution Automation/SCADA*

To what degree has the utility being surveyed employed substation SCADA (Supervisor Control And Data Acquisition) and/or some type of automated switching scheme on the distribution system? In one sense, one could argue that whether a utility employs distribution automation is no different from whether the utility trims its trees. Either, distribution automation or tree trimming, are strategies used to reduce outages or outage duration, and are arguably reasons for higher or lower reliability indices. However, smaller utilities without the means to employ such systems may object to being compared to others who have employed them. Alternatively, those who have such systems may feel that these systems enhance their data collection, similarly to circuit connectivity, resulting in higher indices. Knowing to what extent each survey participant has employed these systems allows utilities to identify more closely with like participants and, more importantly, look at others having higher levels of implementation and identify whether better indices have resulted. Utilities without the financial wherewithal to install these systems will be better able to explain to regulators why their indices appear worse than those that have employed them.

D. *Geography*

What type of geography is served by the utility? Utility service territories may be urban, suburban, or rural, or more likely, some combination of all of these. Distribution systems designed for rural areas are generally comprised of small substations with very long radial circuits extending for many miles, with little redundancy and few circuit ties. Systems in dense urban areas are normally made up of larger substations with multiple supplies, redundant facilities, shorter circuit lengths, and multiple tie paths. Circuit distance alone is a substantial reliability issue; a rural circuit with 20 miles of exposure is inherently less reliable than an urban circuit of 5 miles. More circuit length equates to more exposure and more points of potential failure. Dense urban areas may also employ a larger degree of underground facilities than sparse rural areas. These inherent design differences and levels of system exposure necessitate the geography be known by the participants in order for appropriate comparisons to be made.

E. *Outage Definition*

Any survey should be careful in identifying what outages are expected to be included in the reported indices. Many utilities have developed their own standards for what they include in the outage numbers, eliminating such things as

maintenance (planned) outages, customer-caused outages, public-caused outages, and outages under a certain duration. The survey should clearly spell out what exclusions are proper and require utilities to identify any exceptions to the stated rules. Ideally, exclusions should be kept to a minimum in order to avoid any inequities surrounding even how the exception is identified in the utility's outage system. Even planned outages should be included in the data since utilities employ different construction and maintenance practices which may have positive or negative impact on the required frequency of planned outages. The definition of sustained interruption versus momentary interruption should be clear and used equally among all participants. IEEE 1366-2001 provides definitions and guidance in this area.

F. *Automated Meter Reading (AMR) Outage Reporting*

At the present time, automatic outage reporting through a fixed AMR network is in place at only a few utilities. However, the impact of this type of reporting is already having an effect on the calculated reliability indices at those utilities. Utilities are notified of the outage quicker, so the clock starts sooner. This can have little effect if the utility can respond quickly. However, if the utility is already responding beyond its capabilities, the clock has begun and more customer-minutes will accumulate. More importantly, when combined with circuit connectivity and an automated OMS, these additional AMR outage calls will more correctly identify the extent of the outage and the exact number of customers affected. For example, assume a tap fuse has blown affecting 20 customers, 10 on each of two distribution line transformers. Five phone calls from affected customers are received, all five from customers on the same transformer. The OMS analyzes the incoming call data and incorrectly identifies the transformer as the point of failure. Unless corrected, the outage data will reflect outages to only 10 customers instead of the correct 20. With the implementation of AMR outage reporting, the 5 customer calls are supplemented with AMR reports from all affected meters and the correct customer count is identified. Maintenance outages will also increase because line crews will be required to notify the dispatch office any time an outage is taken, or the AMR outage report will identify a failure to the OMS when there is in fact planned work in progress.

G. *Storm Normalization Methodology*

All surveys require that participating utilities report indices that are inclusive of all outages and indices that have been "storm normalized". Some surveys require the respondent to identify the method of storm exclusion. Since the normalized indices are the most useful for comparisons, having supposedly been normalized for unusual weather patterns experienced by one utility but not another, it is imperative that a method for storm-normalization be determined that is equitable for all utilities. The method

should allow for the exclusion of unusual events while not being so generous to the utility as to understate to regulators and others the actual reliability performance of the utility. The data included in the indices should be reflective of what the customer experiences from year to year. Much work has been done in this area to arrive at an equitable methodology satisfactory to both utilities and regulators, but much work remains to be done before any such method is universally accepted. In the interim, surveys should have respondents clearly identify what storm normalization methodology was employed in the determination of the reported indices.

III. Summary

Utilities and regulators are rightfully looking for ways to benchmark the performance of individual utilities against the utility's own past record as well as against others in the industry. This benchmarking is appropriate only when the proper precautions are taken to segment utilities so that relevant comparisons are made. This segmenting needs to take into not only the utility's location, geography, and system design, but also its data capture and analysis capabilities. Properly done, relevant benchmarks can be extrapolated from survey data and appropriate comparisons made.

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