Introduction

A utility best serves its customers through providing reliable service at a reasonable price. This involves a proper balancing of key performance areas. For example, utility costs and reliability must be balanced—a utility would not wish to become hyper-reliable if such reliability raised retail energy rates excessively beyond the best interests of its customers. Determining the optimal level of reliability for a particular utility is crucial to a well-performing utility.

This article explores a new method for setting the appropriate reliability target: econometric benchmarking. Currently, utilities typically compare their reliability scores against national reliability data. However, this comparison has severe limitations—how helpful is it, for example, for a utility with a rural, heavily vegetated service area to gauge its reliability against a utility with a dense, urban service area? The econometric method of setting reliability targets fixes this problem by setting a customized reliability target for a utility, based on its particular service territory characteristics. The article outlines the method, and presents a sample case study from a utility in the central U.S. (“Midwestern Utility,” or simply “Midwestern”) to illustrate the process.

The Nature of Utility Reliability

The energy distribution and transmission industry is characterized by natural monopolies, which are regulated to assure a reliable supply of energy at reasonable costs. Monopolies are necessary because of the underlying technology and infrastructure needs of the industry. This leaves utilities without direct competitors against which to evaluate cost and service quality levels. Measuring the performance of cost and service quality is crucial, because these are the two primary areas that impact value from the customer viewpoint.

Continued
Unlike most other industries in the economy, distribution utilities have their capital assets spread throughout their entire service territory. The service territory will have an enormous influence on reasonably achievable levels of cost and reliability. Evaluating the performance of energy distribution utilities is confounded by this influence—traditional evaluations often create an “apples to oranges” comparison.

A utility serving a large territory with customers thinly spread throughout it will likely have high costs per customer, as compared to a utility serving more densely populated areas. An electric utility serving an area with vegetation and a tendency for strong winds is likely to have more outages, even if it is generally more effective than its peers in preventing interruptions.

For these reasons, simple rate and reliability comparisons do not properly reveal the performance and productivity levels of the distributor. The operating conditions, even between neighboring utilities, can vary drastically. Like snowflakes, utility service territories are never identical. State, regional, or national surveys of rates or reliability indexes thus provide poor benchmarks when evaluating what those levels should be for a particular utility. In fact, even carefully designed peer groups typically do not provide adequate benchmarks, because of the numerous factors that influence distribution cost and reliability levels.

As an example of the limitation of simple comparisons, consider Midwestern Utility. Midwestern developed its reliability goals using the Edison Electric Institute’s (EEI) annual reliability report, which is based on voluntary and anonymous reliability data. Midwestern established a “top quartile” standard for System Average Interruption Duration Index (SAIDI) of 90 minutes per customer. Utilities with a SAIDI less than 91 minutes are in the first quartile (25% percentile), and are deemed the “Best Performers.” Utilities with a SAIDI of greater than 179 minutes are in the bottom quartile (75% percentile), and are called the “Worst Performers.” Midwestern’s goal was to be a “Best Performer” in 2013.

There are problems with using EEI data to gauge a utility’s reliability. For one thing, submission of data to EEI is voluntary, and so utilities with low reliability data sometimes do not submit their data or drop out of the survey, thus skewing the EEI “averages.” Even if the EEI reported all data, however, the problem remains that a simple comparison to national data is not very helpful. For example, Midwestern’s customer density is much lower than the average utility, and its vegetation challenges are much higher.

Therefore, we would expect Midwestern’s reliability to be “worse” than average. Even comparing Midwestern to an in-state peer (“Big City Utility”) may not be helpful, if that peer serves a dense urban area. On a straight index basis, a utility similar to Big City will likely have superior reliability indexes than Midwestern, because of Big City’s service territory advantages. When evaluating the performance of each utility and setting targets, adjustments must be made for these conditions.

### Issues with Using EEI Data to Gauge Reliability.
- Submission of Data is Voluntary
- Simple Comparison to National Data is Not Very Useful
Setting Econometric Reliability Benchmarks

The econometric modeling approach investigates and estimates the influence of service territory characteristics on cost or reliability levels. This provides a level playing field among distributors who have dissimilar challenges and advantages. For example, a cost model provides the cost level expected from a hypothetical “average-performing” utility that has the same external conditions as the studied utility. This information formulates an adjusted benchmark, to which observed cost and reliability data can be compared.

Another clear advantage of the econometric modeling approach is that it can provide decision-makers with information on how much confidence to place in the evaluation. A probability distribution based on model results illustrates the most likely outcome (benchmark) and its variability. In Figure 1, Utility X’s most likely cost level for the studied year, given its observed operating conditions, is $100 million. Ninety percent of its likely cost levels are predicted to be between $90 million and $110 million. However, Utility X has cost levels at $115 million, which indicate that its cost levels are statistically higher than the benchmark of $100 million, at a 90 percent confidence level.

Factors to be Considered in Econometric Adjustments

Some of the factors that affect electricity cost and reliability levels are:

- Retail customers served
- Retail volumes delivered
- Regional wage and construction cost levels
- Customer density
- Vegetation levels
- Wind levels
- Thunderstorm prevalence
- Serving an urban core
- Load factor
- Vertical integration of generation, transmission, and distribution functions
- Definition of a “major event day”
- Serving gas and electric customers

The comparability issue can be solved through econometrically modeling data from a wide range of service territories, thus quantifying how each factor above affects reliability. From the resulting econometric equation, we can then determine an “expected” cost or reliability level that is customized to each utility*.

A cost benchmarking evaluation is only part of the performance story. For electricity distributors, the reliability of their system is another central piece of the performance puzzle. Power distribution utilities constantly face the dilemma of whether to bolster reliability or maintain rates. Higher levels of reliability often come at the expense of higher costs, and therefore higher rates. As the old economic adage goes, “there is no such thing as a free lunch.”

* A simple peer group benchmarking approach typically uses only a small subset of available data (i.e. the utilities in the peer group). A comprehensive econometric modeling approach uses all of the available industry data to model reliability or costs, i.e. all US and Canadian utilities for which the appropriate data is available.
A proper balance between cost and reliability is vital to the economic well-being of customers and businesses operating within the service territory. If reliability is overly emphasized, a likely result will be electricity rates that are above the optimal level. If low rates are given too much prominence, a probable consequence will be that the economic harm from outages will surpass the savings from the low electricity prices.

The appropriate balance entails setting reliability targets and goals based on customer’s “willingness to pay” to avoid outages and the marginal costs to the utility of avoiding those outages. Stated in economic terms, both the demand curve and the supply curve for reliability should be at the equilibrium point. This is illustrated by the figure below.

In this figure, the vertical axis represents cost, and the horizontal axis represents increased reliability. The purple “supply” line represents how much it costs a utility to add an extra “unit” of reliability, and the red “demand” line represents how much a customer would be willing to pay for another unit of reliability. The optimal reliability point for a utility is where the two lines intersect.

The econometric modeling provides “expected” reliability targets, after adjusting for each utility’s particular environment. For example, the graph shows Midwestern’s recent SAIDI values, and its 2010-2013 goals before performing an econometric adjustment.

Econometric benchmarking will help Midwestern to adjust its reliability target appropriately, in light of Figure 3.

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**“Expected” Reliability**

The problem for Midwestern is that its “supply” line is different than the “average” utility—it costs Midwestern more to improve reliability, because of its vegetation and low density. In effect, its supply line is higher than that of the average utility (see Figure 3). Thus, its optimal reliability will be somewhat lower than that on an average utility (the intersection of the green and red lines).

The problem is that these goals were based on a top quartile of unadjusted EEI scores. However, we have already seen that Midwestern faces a more difficult service area than the average utility. The “top quartile” cutoff needs to be adjusted. This is done by selecting a group of utilities, and determining what their expected reliabilities are, and then comparing their actual reliability to the expected reliability. A simplified table depicting this process is shown in Table 1 on the next page.
In Table 1, a sample of twelve utilities is analyzed. The “Initial Quartile” is based on a simple comparison of SAIDI scores. On that measure, Utilities B, E, and F are in the first quartile, because they have the lowest SAIDI scores. However, each utility is then compared to its “expected” score. The expected SAIDI is calculated econometrically, taking into account the bulleted factors listed previously. Thus, Utility A’s expected SAIDI of 124 is what would be expected for an “average” hypothetical utility with A’s customer density, vegetation levels, wind levels, etc.

Each utility is then ranked by how much it came under or over its expected score. After adjustment, Utility A was the top performer, even though it was on in the 2nd quartile based on the “raw” SAIDI scores.

This process can also be done for cost performance. Customized, model-based benchmarking can provide the current status of a utility’s cost/reliability balance. Figure 5 presents the adjusted cost/reliability performance of 69 U.S. electric utilities over a three-year period, as measured by the System Average Interruption Frequency Index (“SAIFI”). The SAIFI model measures performance by modeling the effect of such factors as customer density, vegetation levels, wind conditions, size, and major event exclusion criteria on outage duration.

One aspect of performance involves delivering service efficiently with minimal costs, given a certain service quality target. Another aspect, especially germane in the electric distribution industry, is determining what that service target should be. Figure 5 illustrates categories of adjusted performances. The figure answers the first aspect of performance; however, it does not answer the question of “What should our reliability target be?” In terms of Figure 5, what quadrant should a utility strive to be in given its supply and demand curves for reliable electricity?

Table 1: Quartile Adjustment*

<table>
<thead>
<tr>
<th>Utility</th>
<th>Unadjusted SAIDI</th>
<th>Initial Quartile</th>
<th>Benchmark (Expected SAIDI)</th>
<th>Difference</th>
<th>Adjusted Rank</th>
<th>Adjusted Quartile</th>
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<tr>
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<td>110</td>
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<td>124</td>
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<tr>
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<td>4th</td>
<td>134</td>
<td>8</td>
<td>3</td>
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</tr>
<tr>
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<td>111</td>
<td>2nd</td>
<td>118</td>
<td>7</td>
<td>4</td>
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</tr>
<tr>
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<td>1st</td>
<td>95</td>
<td>6</td>
<td>5</td>
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</tr>
<tr>
<td>F</td>
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<td>100</td>
<td>2</td>
<td>6</td>
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<tr>
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<td>3rd</td>
<td>110</td>
<td>-2</td>
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<td>3rd</td>
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</table>

*Table 1 uses hypothetical utilities and SAIDIs.

Figure 5: Cost/Reliability Industry Position
The profound service territory differences among utilities lead to far different supply curves and overall costs in achieving a given reliability level. These diverse supply curves require statistical analysis to properly customize performance evaluations and set targets. Likewise, a utility’s customers have different preferences for reliability versus electricity rates. The demand curve should be incorporated into determining the optimal reliability level of a given utility.

**Conclusion**

Electric utilities should not all have the same reliability targets. There should be a healthy spread between utilities with easier operating conditions and higher customer demand for reliability, to those utilities with more challenging conditions and lower customer demand for reliability. Attempting to hit an arbitrary goal based on simple rankings will lead to outcomes that are not in the interests of the customers and ratepayers of the utility.

**Setting Targets When Customer Demand for Reliability is NOT “Average”**

As an example, say that the supply curve reliability model estimates that an “average-performing” utility with the same operating conditions as Utility X would have a SAIFI value of 1.00. Given the business types and customer preferences for reliability, Utility X’s customers place 10 percent less value on avoiding outages than their average counterparts at other utilities do. In this simplified example, Utility X’s SAIFI target should be raised by 10 percent, in other words set at 1.10 outage minutes per customer**. Figure 7 illustrates the inputs into deciding Utility X’s proper reliability target.

**Midwestern’s initial SAIDI goal of 90 was inefficient. It would result in Midwestern spending too much on reliability. We calculated Midwestern’s “expected” SAIDI econometrically, and arrived at an expected SAIDI of 133.6. In other words, the model put the SAIDI for an average-performing utility with Midwestern’s characteristics at around 134. Midwestern decided that it would like to have a 90% confidence that its new adjusted target would be a “superior” reliability performance (in the top half), and so it chose a target of 105. This target is much more achievable and reasonable than the original unadjusted top quartile target of 90, but it still allows Midwestern to strive for superior reliability.**

**Setting New Reliability Targets for Midwestern**

If a utility’s customers have an average “willingness to pay” for reliability then it can formulate a reliability target simply based on (for example) the new quartiles. As we saw above, Midwestern originally used the EEI “top quartile” target, so that it intended to get its SAIDI under 91 by 2013. However, PSE’s analysis showed that this target was much too ambitious for Midwestern, given its challenging service characteristics: achieving this goal would have put Midwestern on the far right side of its supply curve, as in Figure 6 below.

**Figure 6: Inefficiently High Reliability**

Midwestern’s initial SAIDI goal of 90 was inefficient. It would result in Midwestern spending too much on reliability. We calculated Midwestern’s “expected” SAIDI econometrically, and arrived at an expected SAIDI of 133.6. In other words, the model put the SAIDI for an average-performing utility with Midwestern’s characteristics at around 134. Midwestern decided that it would like to have a 90% confidence that its new adjusted target would be a “superior” reliability performance (in the top half), and so it chose a target of 105. This target is much more achievable and reasonable than the original unadjusted top quartile target of 90, but it still allows Midwestern to strive for superior reliability.

**Figure 7: Determining the Optimal Reliability Target of Utility X**

The profound service territory differences among utilities lead to far different supply curves and overall costs in achieving a given reliability level. These diverse supply curves require statistical analysis to properly customize performance evaluations and set targets. Likewise, a utility’s customers have different preferences for reliability versus electricity rates. The demand curve should be incorporated into determining the optimal reliability level of a given utility.

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**This assumes that the industry as a whole is at the equilibrium cost/reliability balance (see Side Issue on page 7). It also assumes that increasing SAIFI is linearly related to cost. Our empirical research estimates that costs are not linearly related to the SAIFI achieved. As the target gets easier, the marginal costs of avoiding outages become less. As the target gets more difficult, the marginal costs of avoiding an outage is higher.**
Economic theory posits that the optimal position is when the marginal costs of improving system reliability equals the marginal benefits of avoiding outages.

Side Issue: Is the Industry at the Cost/Reliability Equilibrium?

With recent large storms (e.g., Super Storm Sandy) wreaking havoc on the electricity grids of major metropolitan areas, the question of whether the industry should be increasing its investment in infrastructure and reducing the prevalence of electricity outages is a popular topic. Specific utilities do, and should, have different reliability levels based on their circumstances and the customer demand within their territories. However, what about the electric distribution industry as a whole? Is the electric industry at the proper cost/reliability balance or should distributors be spending more (or less) money to improve or maintain reliability levels?

Economic theory posits that the optimal position is when the marginal costs of improving system reliability equals the marginal benefits of avoiding outages. For the electric distribution industry to be at the proper equilibrium this condition should be met. If the marginal costs are significantly lower than the marginal benefits, then the industry, as a whole, should spend more money to improve reliability, likewise, if the marginal costs are significantly higher than the marginal benefits then less money should be spent and it would be optimal to allow reliability to deteriorate over time.

This issue was investigated by looking at the United States electric industry. Publically-available cost and reliability data was gathered. This allowed us to estimate the marginal costs of avoiding an outage. The research conducted by the author shows that at the industry mean, the marginal costs of avoiding one customer outage lasting an average of 90 minutes has a range of $250 to $500.

In a June 2009 report, Lawrence Berkeley National Laboratory (LBNL) estimates that a sustained outage creates approximately $300 of economic damage for the average customer (including residential, commercial, and industrial), based on our calculations of the estimates found within the report. This assumes an average outage time of 90 minutes*. Naturally, estimates of customer demand have a wide confidence interval range both within and between studies.

Based on the analysis of the marginal costs of reliability being between $250 to $500 combined with the estimate range of the customer demand of avoiding a sustained outage being around $300, it appears the industry is close to an optimal cost/reliability equilibrium. It is, thus, reasonable to calculate customized targets for utilities based on their specific supply and demand curves benchmarked off of the differences from the electric industry at large.


About the Author

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Steve received a BS in Economics and MS in Agricultural and Applied Economics from the University of Wisconsin-Madison. Steve has been a consultant in the energy utility industry for twelve years. He is an expert in utility performance benchmarking, incentive regulation, value-based reliability planning, productivity analysis, and DSM. Steve has provided senior-level consulting services, presented findings, and conducted expert witness testimony for locally-owned utilities, IOUs, regulatory commissions, trade associations, and consumer advocates. He has published a number of peer-reviewed journal articles on these and other topics.

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