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# Smart Grid Economics: The Cost-Benefit Analysis

## It is possible for utilities to systematically assess the economic benefits that can result from reliability improvements.

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In the context of debates about the cost-effectiveness of smart grid reliability investments, it is necessary for utilities and regulators to have a common framework for cost-benefit analysis that properly accounts for the societal benefits that arise from utility investments in reliability. The key challenge in developing this framework lies in adopting practical rules for assessing the economic value of service reliability.

Smart grid investments can yield a wide range of benefits that fall into different categories, such as environmental and security benefits. This discussion, however, addresses the economic benefits that can result from reliability improvements.

Economic benefits reflect efficiency improvements in the use of capital, fuel and labor in the generation, transmission and distribution of electricity, including conservation impacts resulting from providing better information and pricing to consumers. Reliability benefits are the reduced costs to utilities and customers resulting from fewer service interruptions and power-quality disturbances.

In general, reliability problems fall into two distinct categories: service interruptions/outages and power-quality disturbances (i.e., momentary interruptions and voltage disturbances). And for most intents and purposes, interruption costs and power-quality costs can be treated in the same way when considering the economic value of reliability improvements.

Additionally, there are three important dimensions of electric-service reliability: the number of customers affected, the frequency with which outages or voltage disturbances occur, and the duration of service interruptions.

Reliability can be measured in a variety of ways. For the purposes of transmission and distribution planning, it is measured in two ways. One approach is to estimate the quantity of unserved energy (in kilowatt-hours) that results, or is expected to result, from service interruptions. This approach requires an estimation of the quantity of kilowatt-hours that would have been demanded if electricity had been available during those interruptions.

This method rests on a very difficult estimation problem - namely, the requirement to estimate the quantity of electricity that would have been demanded if unreliability had not occurred. The estimation of unserved kilowatt-hours would need to take into account the time of day, the day of the week and the season of the year during which the outages occurred. These assumptions can strongly affect the estimates of expected unserved energy, adding a significant source of uncertainty.

> Are the changes in these reliability indicators large enough to justify the costs of the investments required to achieve them?

In turn, objective statistical indicators of reliability are more commonly used when assessing the reliability of systems. Most utilities and regulatory bodies in the U.S. commonly describe the reliability of transmission and distribution circuits in terms of simple, readily obtainable and transparent indicators. These indicators are:

- **SAIDI**: system average interruption duration index (the sum of all outage durations divided by the number of customers);
- **SAIFI**: system average interruption frequency index (the count of all extended outages divided by the number of customers);
- **CAIDI**: customer average in-

terruption duration index (SAIDI divided by SAIFI); and

- **MAIFI**: momentary average interruption frequency index (the count of momentary outages divided by the number of customers).

These definitions can provide a valuable basis for assessing changes in the reliability of electric transmission and distribution systems over time. Because utilities normally maintain accurate records of outages and service-restoration time, the statistics can be calculated for feeders, substations, planning areas, transmission circuits and utility systems. They are all averages that describe slightly different aspects of service reliability.

### *The cost of unreliability*

Smart grid reliability investments can be expected to affect these reliability indicators in systematic ways. They should cause changes in the average duration of interruptions, changes in the average frequency of sustained interruptions and changes in the average frequency of momentary interruptions.

From the point of view of evaluating the benefits of smart grid investments, there is one key question: Are the expected or observed changes in these reliability indicators large enough to justify the costs of the investments required to achieve them?

To answer this question, three pieces of information are required:

- The utility costs required to achieve given levels of reliability (i.e., investment, maintenance and operating costs);
- The changes in CAIDI, SAIFI and MAIFI that will result from a given smart grid investment or set of investments; and
- The average economic losses resulting from the aforementioned units of unreliability (i.e., CAIDI, SAIFI and MAIFI) - in other words, it is necessary to develop estimates of how much a CAIDI minute costs and how much a SAIFI event costs.

The cost of unreliability is the product of the second and third preceding points. In general, the reliability benefit is calculated by comparing the outage costs that occur in a baseline condition (i.e., existing SAIFI, CAIDI and MAIFI), with the outage cost that occurs, or is expected to occur, as a result of the investment. The difference in the cost of unreliability for the baseline condition and the cost that results from the investment is the reliability benefit, and the ratio of the reliability benefit to the investment cost is the relevant cost-benefit ratio.

Economic benefits from reliability investments can flow to both utilities and their customers. Reliability benefits flow to utilities in the form of reduced operating and maintenance costs, and reduced costs of service restoration. Benefits flow to customers in the form of the avoided economic losses they experience due to unreliability.

Because all of the costs of system reinforcements flow to utilities (and indirectly to their customers through rates when utilities are allowed to recover them), utility planners often ignore customer benefits in cost-benefit calculations related to service-reliability improvements. However, because benefits accruing to customers can be very large when reliability is improved, ignoring them in assessments of costs and benefits of reliability improvements can significantly undervalue service-reliability improvements.

### *Assessing reliability*

As previously stated, assessing the economic impacts of transmission and distribution reliability investments requires the estimation of the utility costs, reliability impacts and resulting outage costs associated with investment and operating alternatives. The utility cost estimates associated with supplying reliability are, in a sense, relatively hard numbers - that is, they are based on straightforward engineering cost-estimation techniques combined with assumptions about operating and maintenance costs, which can be estimated and verified by historical data.

The reliability impacts and interruption costs to customers are inherently more uncertain. The historical reliability of electric-supply systems is usually known. It is usually possible to accurately calculate SAIFI, CAIDI and MAIFI for system components. After an investment is made, the performance of modified systems can also be observed using the same indices, so one might imagine that *ex post* comparisons of reliability performance (i.e., before and after system improvements have been made) would capture the effects of investments on reliability. Unfortunately, the situation is not so simple.

Year-to-year statistical variation in reliability indicators can obscure or magnify the observed impacts of reliability improvements. Moreover, reliability should not be thought of as static. Circuit reliability generally declines over time as load increases and system components age.

Therefore, both the baseline reliability level and reliability levels observed after investments are made are subject to uncertainty. The magnitude of that uncertainty depends on the historical year-to-year variation in reliability indices and observed trends in reliability upon which the analysis of reliability is based. When assessing reliability impacts, care must be taken to incorporate thorough analysis of the impacts of uncertainty in these estimators.

Even more serious problems can arise in making *ex ante* projections of the impacts of investments on reliability. In making ex ante projections of reliability indicators, it is necessary to forecast future reliability, either by simulating the performance of the subject system (e.g., circuit or planning area) under different circuit design assumptions or by engineering judgment.

In either case, projected changes in circuit performance must rest on assumptions that should be carefully scrutinized to ensure reasonableness. This is an area where simulation modeling and other analytical techniques could prove very useful, but a framework for conducting such analysis needs to be developed.

### *Wrangling uncertainty*

Interruption-cost estimates are also subject to uncertainty - but for different reasons. Interruption costs have been estimated in a variety of ways, and depending on the approach used to estimate interruption costs, significant differences in estimated interruption costs have been observed. The choice among interruption-cost estimation methods is important in that the average estimates from the different methods can vary by as much as a factor of 10.

There are five basic alternatives available for estimating interruption costs: customer-survey-based estimates (e.g., customer outage-cost surveys); the use of macroeconomic indicators (e.g., GDP); case-study estimates (e.g., various blackouts); market-based methods (e.g., amounts paid for backup generation); and rule-of-thumb methods (e.g., undocumented costs).

Each of these methods has its strengths and weaknesses. But on balance, the results of studies conducted over the last three decades from such entities as the Electric Power Research Institute and IEEE suggest that interruption costs can be best estimated using survey-based methods.

These methods are costly, but they are designed to collect reported interruption costs from customers - the parties who likely have the most accurate and reliable information concerning the costs they incur when their homes and businesses experience outages.

Survey-based methods are the most widely used among the interruption-cost estimation procedures. In part, this is because most analysts believe that customers are the most qualified to estimate their interruption costs. In addition, costs obtained in this manner can be applied to a wide variety of geographical areas and interruption circumstances.

The principal weakness of survey-based outage-cost estimation methods is that they are usually based on answers given by customers to questions about hypothetical power-interruption scenarios. In other words, they do not ask customers about costs they have experienced, but instead about costs they think they would experience.

It is notable that the extent of bias that might be induced by asking about hypothetical outages has never been studied, because no one has considered the problem to be important enough to fund systematic research to address the issue.

> Failing to account for the differential impacts of frequency and duration can lead to highly inaccurate estimated benefits.

### *Reliability benefits*

In terms of calculating reliability benefits, the most common approach is to apply the cost per unserved kilowatt-hour from the interruption-cost estimates. Benefits calculated from this approach are a direct function of the change in the number of interrupted hours (from what is experienced under a baseline condition to what is experienced after smart grid investments are made). Whether this change is a result of reduced interruption frequency or reduced interruption duration does not have an effect on the calculation.

However, failing to account for the differential impacts of frequency and duration can lead to highly inaccurate estimated benefits. Consider two possible smart grid investments: One would reduce the interruption duration by 50%, and the other would reduce the interruption frequency by 50%. Both reduce the number of interrupted hours by 50%, but the value of each investment is quite different.

Assume that in the baseline scenario, a typical large commercial customer experiences a single one-hour interruption each year, and this one-hour interruption costs that customer $12,487 per year. The investment alternative that leads to a 50% reduction in interruption duration will result in a situation in which the customer still experiences one interruption per year, but this interruption will now only last 30 minutes.

The 30-minute interruption costs the customer $9,217 per year. In the end, the investment that reduces interruption duration by 50% has an average annual benefit of $3,270.

The investment alternative that leads to a 50% reduction in the interruption frequency will result in a situation where the average interruption duration is still one hour, but the probability of experiencing an interruption is reduced by 50%. Therefore, a one-hour interruption still costs the customer $12,487, but because the probability of experiencing an interruption in a given year is now 50% as opposed to 100%, the interruption cost to the customer is now $6,244 per year.

Although the reduction in the number of interrupted hours is the same for both investments, the one that reduces interruption frequency provides nearly double the value.

The cost-per-event approach separately considers the benefits associated with frequency and duration. However, much like with other smart grid benefits, frequency and duration benefits overlap and cannot be considered in isolation, which requires a joint approach for the calculation.

Because this approach is slightly more complicated, the estimations use utility metrics, such as SAIFI and CAIDI. If the average interruption duration changes as a result of a proposed investment, the cost per interruption varies between the baseline and projected scenarios. Therefore, the estimated cost per interruption per event can be calculated based on the estimated CAIDI before and after the proposed investment.

This approach will accurately capture the differential effects of frequency and duration, which can be substantial. Considering that many planners compare the benefits of investments that have differential impacts on frequency and duration, it is important to not focus solely on the number of interrupted hours.

For sustained interruptions, it is recommended that planners use the cost-per-event approach to calculate reliability benefits. For power-quality disturbances (momentary interruptions, and voltage sags and swells), further research is necessary to determine whether or not the cost-per-event approach leads to accurate estimates of reliability benefits. (However, it is useful to note that the cost-per-unserved kilowatt-hour approach cannot apply here because there are little to no unserved kilowatt-hours during power-quality disturbances.)

In summary, utilities can successfully calculate reliability benefits based on well-established reliability statistics that they most likely collect on a routine basis. However, historical data and assumptions involved in the estimation of ex post and ex ante reliability impacts should be carefully documented, including the raw components of reliability indices used in the calculations.

When examining smart grid cost-benefit equations, regulators are increasingly seeking as much information as possible, in terms of the statistical analyses used to quantify the impacts of investments on reliability. Therefore, it is becoming more important to understand and document how power-quality disturbances are measured and whether these measurements are accurate. ⌗

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