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Evaluating Smart Grid Reliability Benefits For Illinois

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How to Assess the Economic Consequences of Smart Grid Reliability Investments

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1 INTRODUCTION

1.1 What is the Smart Grid?

The Smart Grid consists of a number of technological improvements that can be made in transmission and distribution systems. These improvements have been evolving over several decades in the electric utility. In general, these technologies are designed to improve the performance of transmission and distribution systems by:

- Installing sensors that can detect system conditions that indicate failures either have occurred or will occur in the near future (e.g., abnormal temperature readings on heat sensitive equipment);
- Incorporating fast-acting microprocessors that can quickly detect fault conditions and take action (in concert with other system components) to anticipate failures and reconfigure circuit supply routes or restore service as quickly as possible to customers that can be served by alternative supply lines;
- Reconfiguring radial circuits adding normally open points with automatic switches that can be closed to restore service to customers surrounding isolated faults automatically;
- Adding voltage regulation and capacitance down-stream of substation transformers to reduce line losses – thus improving energy efficiency; and
- Installing AMI meters that provide a wide range of benefits including:
    - Reduced cost of meter reading
    - Improved ability to detect outages and restore service quickly after outages;
    - Improved theft detection; and
    - Improved access for customers to information about the timing and magnitude of electricity consumption.

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. This will become increasingly important as society becomes reliant on electricity to supply critical energy requirements in buildings and transportation. The key challenge in developing this framework lies in adopting practical rules for assessing the economic value of service reliability – the primary focus of this report.

1.2 The Benefits of Smart Grid

A wide range of benefits arise from Smart Grid investments. A reasonably exhaustive categorization of these benefits was assembled by EPRI for DOE (2010) to support the evaluation activities that are being undertaken in conjunction with assessing the impacts of the U.S. Government's Smart Grid Investment Grants (SGIG). Table 1-1 provides a list of Smart Grid benefits contained in that report. They fall into four basic categories:

- Economic benefits – improvements in the efficiency 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 – reduced costs to utilities and customers resulting from service interruptions and power quality disturbances;
- Environmental benefits – reduced emissions associated with electricity generation (i.e., CO_2, NO_X, SO_X and PM-10); and
- Security benefits – reduced reliance on oil and reduced likelihood of widespread blackouts.

This paper discusses the economic benefits that can arise from *reliability* improvements associated with Smart Grid investments; and in particular discusses alternative methods for assessing the economic worth of these investments. Along the way, reasonable estimates of interruption costs are provided for purposes of evaluating projects in the near term; and recommendations are made for improving the analysis in the future – particularly for evaluations being carried out by the Illinois Commerce Commission (ICC).

Table 1-1:
List of Smart Grid Benefits

Benefit Category	Benefit Sub-category	Benefit
Economic	Improved Asset Utilization	Optimized Generator Operation Deferred Generation Capacity Investments Reduced Ancillary Service Cost Reduced Congestion Cost
	T&D Capital Savings	Deferred Transmission Capacity Investments Deferred Distribution Capacity Investments Reduced Equipment Failures
	T&D O&M Savings	Reduced Distribution Equipment Maintenance Cost Reduced Distribution Operations Cost Reduced Meter Reading Cost
	Theft Reduction	Reduced Electricity Theft
	Energy Efficiency	Reduced Electricity Losses

Benefit Category	Benefit Sub-category	Benefit
	Electricity Cost Savings	Reduced Electricity Cost
Reliability	Power Interruptions	Reduced Sustained Interruptions Reduced Major Interruptions Reduced Restoration Cost[1]
	Power Quality	Reduced Momentary Interruptions Reduced Sags and Swells
Environmental	Air Emissions	Reduced CO_2 Emissions Reduced SO_x, NO_x, and PM-10 Emissions
Security	Energy Security	Reduced Oil Usage Reduced Wide-Scale Blackouts

Source: EPRI (2010). Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects. Report no. 1020342. Palo Alto, CA: EPRI.

1.3 The Elements of Reliability

The reliability of electricity supply refers to the ability of the bulk electricity supply system to provide electricity within the accepted standards of power quality (i.e., frequency and wave form) when it is demanded. In general, reliability problems fall into two distinct categories – service interruptions/outages and power quality disturbances (i.e., momentary interruptions and voltage disturbances). While it is possible to imagine a wide range of technical definitions for interruptions and power quality disturbances, Title 83 of the Administrative Code for the Illinois Commerce Commission provides reasonably refined definitions of the elements of both reliability categories. According to Part 411 of the Code, an interruption or outage:

> "…means the failure or operation of a single component or the simultaneous failure or operation of physically and directly connected components of a jurisdictional entity's transmission or distribution system that results in electric service to one or more of its customers being lost or being provided at less than fifty percent of standard voltage for a period of longer than one minute in duration and requiring human intervention by the jurisdictional entity to restore electric service."

The Code specifically excludes a number of service interruption conditions from the definition of an interruption including:

- Those caused by the operation of substation breakers and other automatic switches and reclosing devices;
- Non-firm service operations;

[1] For this report, we consider reduced restoration cost as an economic benefit that is part of T&D O&M Savings. Therefore, the focus is on customer benefits associated with reductions in interruptions and power quality disturbances.

- Interruption for non-payment, tampering or denial of access;
- Interruptions to preserve public safety; and
- Scheduled interruptions for maintenance.

The code defines power quality disturbances as:

> "Power fluctuation" or "Surge" means departure of more than one-minute duration in the frequency or voltage of power supplied to the customers' point of service that is caused by the failure or operation of a single component or simultaneous failure or operation of directly connected components of a jurisdictional entity's transmission or distribution system that exceeds the Commission's standards for frequency and voltage (or, where the customer and the jurisdictional entity have agreed on frequency and voltage standards, exceeds the variation allowed thereby), and that causes damage to customer goods."

The Code specifically excludes voltage fluctuations caused by:

- Storms;
- Customer tampering;
- Damage due to civil or international unrest;
- Damage caused by animals and damage caused to the jurisdictional entity's equipment by third parties.

1.4 Reliability Measurements

For most intents and purposes, interruption costs and power quality costs can be treated in the same way when considering the economic value of service reliability improvements. In the discussion that follows, except where specifically noted, the term 'reliability' will refer to both service interruptions and power quality disturbances.

There are three really important dimensions of electric service reliability – the number of customers affected, the frequency with which outages or voltage disturbances occur and (for service interruptions) their duration. Correspondingly, electric service reliability is generally described in terms of how frequently reliability problems occur, how long they last and how many customers are affected.

Reliability can be measured in a variety of ways. For purposes of transmission and distribution planning it is measured in two ways. One approach is to estimate the quantity of un-served energy (kWh) that results (or is expected to result) from service interruptions.[2] This approach requires estimation of the quantity of kWh that would have been demanded if electricity had

[2] The measurement of reliability is not appropriate for quantifying the magnitude or impacts of power quality disturbances since energy supply is not usually interrupted to any significant degree during these problems.

been available during the interruptions that customers experienced or are expected to experience. While this definition has intuitive appeal, it 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. This is an extremely difficult problem because electricity demand varies dramatically with time of day, season, weather conditions and a host of customer characteristics. Correspondingly, the estimation of un-served kWh for transmission and distribution system outages must rest on assumptions about the demand that would have been present given the time of day, season and day of week on which outages occur. These assumptions can strongly affect estimates of expected un-served energy and this is a powerful source of uncertainty in reliability estimates derived using this approach. This is not a serious concern for generation and transmission reliability estimation because loads served by these facilities are usually diverse and reasonably predictable from weather conditions, day, week, time of day and other factors. This is less the case with distribution circuits where demand varies dramatically from circuit to circuit depending on the types of customers served, local weather conditions and so on.

There are objective statistical indicators of reliability that are more commonly used in assessing the reliability of distribution systems. Most utilities and regulatory bodies in the United States commonly describe the reliability of transmission and distribution circuits in terms of simple, readily obtainable and transparent reliability indicators. These indicators are:

1. SAIDI – the system average interruption duration index = $\frac{\text{sum of all outage durations}}{\text{number of customers}}$

2. SAIFI – the system average interruption frequency index = $\frac{\text{count of all extended outages}}{\text{number of customers}}$

3. CAIDI – customer average interruption duration index = $\frac{\text{SAIDI}}{\text{SAIFI}}$

4. MAIFI – momentary average interruption frequency index = $\frac{\text{count of momentary outages}}{\text{number of customers}}$

Definitions of the above indicators vary from one regulatory jurisdiction to another depending on the definitions of the elements of an interruption. For example, in some jurisdictions, sustained interruptions are those that last at least five minutes; while in other jurisdictions, sustained interruptions are those that last more than one minute.

In most jurisdictions, outages resulting from severe weather (e.g., ice storms, hurricane force winds, etc.) and other natural disasters such as earthquakes, floods and fires are not counted in the reliability indices. However, the definitions of these unusual conditions vary somewhat from jurisdiction to jurisdiction. Variation in the underlying definitions of outages that are considered "countable" for purposes of describing reliability makes comparisons of reliability *across* jurisdictions using these indices somewhat unreliable. However, over time, these definitions generally do not vary *within* jurisdictions and therefore these indicators 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 above statistics can be calculated for feeders, substations, planning areas, transmission circuits and utility systems. They are averages that describe slightly different aspects of service reliability. SAIDI is the average duration of extended outages experienced by *all* customers over a given time interval – usually a year. It is the average duration of outages per customer for the system as a whole. It is usually expressed in hours and minutes. This average *duration* includes all of the durations for *all* of the events that *all* customers experience during the relevant time period. SAIFI is the average *frequency* of interruptions that customers experience over a given interval – again usually one year. It is usually expressed as a rational number (e.g., 1.5, 20, 13.2, etc.). CAIDI is the average duration or length of an interruption *for those customers who experienced interruptions* – or the average time from initial discovery of the outage to service restoration. It is also expressed in hours and minutes. MAIFI is the average frequency of momentary outages. It is expressed as a rational number.

Part 411 of Title 83 of the Administrative code sets forth definitions of SAIFI and CAIDI that are consistent with the above discussion. Extended duration outages under these rules are those lasting more than one minute and momentary outages are excluded from reliability calculations altogether.

1.5 Reliability Benefits

Smart Grid reliability investments can be expected to affect the above described 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 these investments, the question is: *are the expected or observed changes in these reliability indicators large enough to justify the costs of the investments required to achieve them*?[3]

[3] Reliability benefits also arise from changes that Smart Grid technology can make in the cost of service restoration. The Smart Grid consists of a large number of sensors that have been installed at various service points. These sensors can be used to diagnose the locations where faults have occurred and to determine whether efforts to restore service have been effective. Installations of these devices can cause service to be restored more quickly. In addition to the reduction in outage duration that corresponds with this reduction in service restoration time, there is a reduction in the labor and capital cost that is required to restore service.

To answer these questions 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 above units of unreliability (i.e., CAIDI, SAIFI and MAIFI). For example, we need to develop estimates of how much a CAIDI minute costs customers, how much a SAIFI event costs and how much each momentary is worth.

The *cost* of unreliability is the product of the second and third points made above. 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 (1) is the relevant cost-benefit ratio.

Economic benefits from reliability investments can flow to utilities *and* to 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 to the society as a whole.

1.6 Value Based Reliability Planning

For many years economists have advocated evaluating utility reliability investments taking into account, not just the costs and benefits experienced by the utility, but the *total* cost of service reliability – that is, taking into account the costs and benefits experienced by both the utility and its customers. This approach to evaluating reliability investments has been called Value Based Reliability Planning (VBRP). In the VBRP framework, reliability investments are evaluated according to their impacts on the *total* cost of reliability – including investment costs, maintenance costs, operating costs *and* customer costs experienced as a result of the delivered level of reliability.

Figure 1-1 shows how the cost of service reliability is defined within the VBRP framework. Utility costs of supplying service (investment, maintenance and operating) generally increase as service reliability increases. Moreover, because each incremental improvement in reliability comes at a higher cost as reliability increases, the relationship between reliability and utility cost is non-linear – reflecting diminishing returns on investment as reliability approaches perfection. As reliability improves, the cost of unreliability experienced by customers decreases at a diminishing rate as reliability approaches perfection.

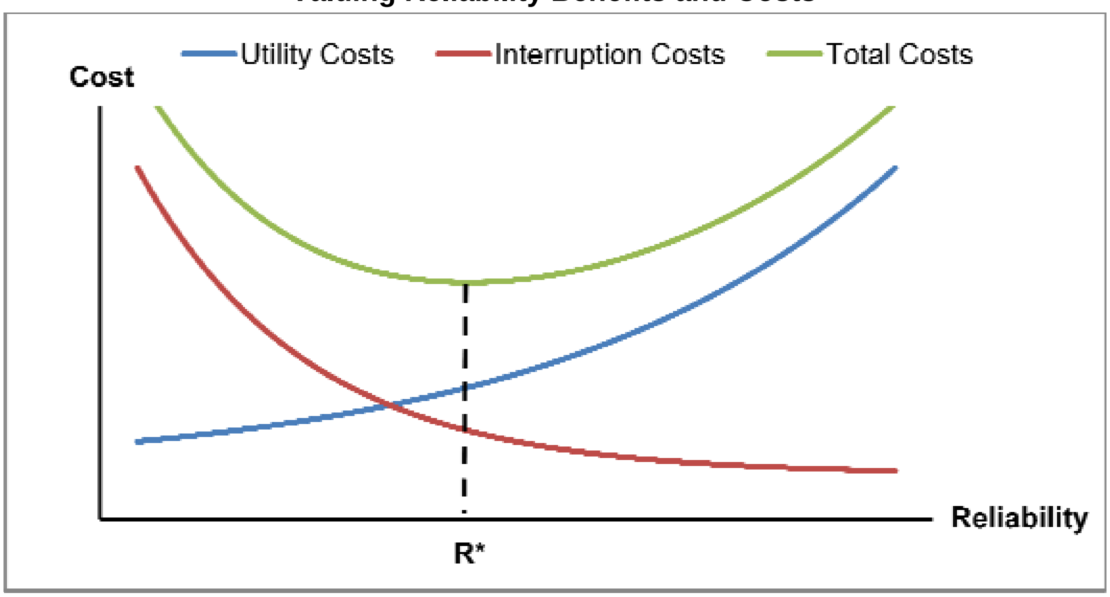
The total cost of service reliability is the *sum* of the utility costs and the cost of unreliability experienced by customers. As is apparent in Figure 1-1, in theory it is possible to identify an *optimal* point of investment in reliability – the point "R" on the graph. This is the point at which the total cost of service reliability is a minimum. If the utility invests less than "R," the total cost of service reliability is higher than it should be (because customers are experiencing outage costs that could be cost effectively avoided by utility investment). If the utility invests more than "R" the total cost of service reliability is higher than it should be (because the costs of the avoided unreliability are less than the investment costs made to avoid them).

The ICC has recognized the legitimacy of evaluating reliability investments using the total cost of service reliability in Title 83, Section 411 where it states:

> "Potential service reliability improvements should be evaluated considering the costs and benefits of the improvements to the jurisdictional entity and to customers."

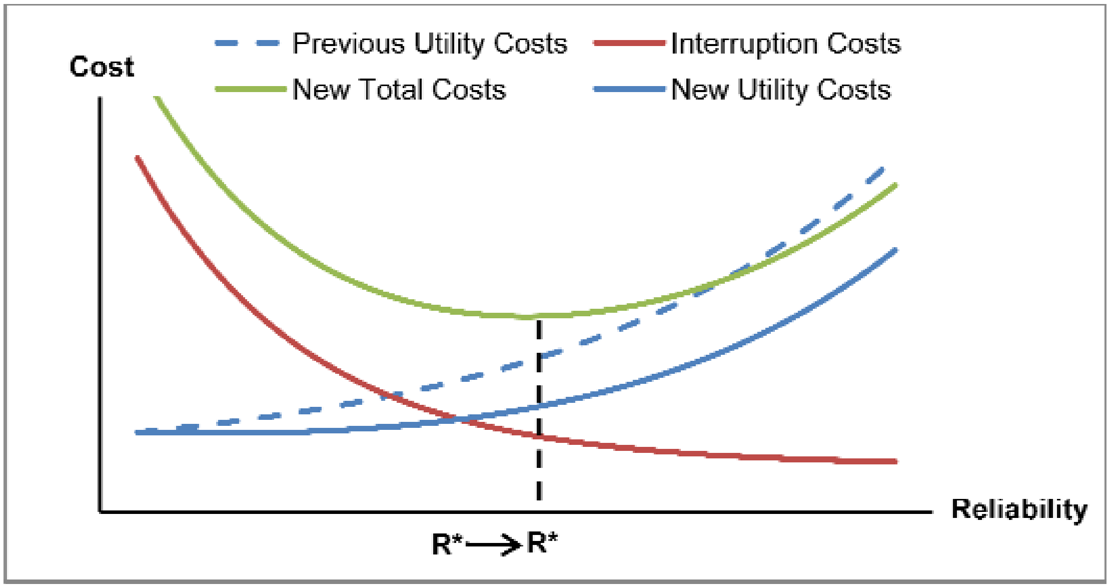
In other words, the Administrative Code calls for assessing the economic value of reliability improvements taking into consideration the costs and benefits experienced by both the utility and its customers.

Figure 1-1:
Valuing Reliability Benefits and Costs



Implementing an approach for assessing the costs and benefits of reliability investments is especially important in today's dynamic environment. The structure of utility costs has changed substantially in recent years. Smart Grid technologies may allow utilities to achieve higher reliability at a lower cost. Many of these technologies are also eligible for financial support from the federal government, which also lowers utility investment costs. Figure 1-2 shows how the optimal level of reliability changes as utility investment costs decline. The new utility costs as a result of new technology and outside funding can achieve each level of reliability at a lower cost. Because the evidence suggests that customer interruption costs change very slowly (if at all) over time (Sullivan et al., 2009), the reduction in utility costs, the optimal level of reliability "R" is higher than before even though the total costs may be lower.

Figure 1-2:
Value-Based Reliability Planning as Utility Costs Decrease



Some early advocates of VBRP argued that utilities were "gold-plating" electricity supply systems by investing too much in reliability (Shipley et al., 1972; Telson, 1975; Bental and Ravid, 1982). This argument mainly concerned investments in electricity generating capacity (by vertically integrated utilities and later by qualifying facilities) throughout the 1970s and 1980s. The reasoning of the proponents of this argument was that because utilities receive a fixed rate-of-return on their capital investments, there is an incentive for them to overinvest in system reliability, which they probably did not ignore. The controversy surrounding the wisdom of investment in generating capacity has died out as wholesale power markets have been established and other regulatory changes have occurred since the early 1990s. However, there is still fertile ground for disputes to arise about the issue of gold plating investments in transmission and distribution systems and Smart Grid investments are perhaps the most fertile ground at present for such disputes to grow.

1.7 Challenges in Estimating the Value of Service Reliability

As explained above, assessing the economic impacts of transmission and distribution reliability investments requires *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 from historical data.

The reliability impacts and interruption costs to customers are inherently more uncertain. The historical reliability of electric supply systems is usually known. That is, it is usually possible to accurately calculate SAIFI, CAIDI and MAIFI for system components. After the fact of an investment, the performance of modified systems can also be observed using the same indices, so one might imagine that an *ex post* comparisons of reliability performance (i.e., before and after installation of system improvements have been made) would capture the impacts 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. So both the baseline reliability level and reliability levels observed after investments are made are subject to uncertainty. The magnitude of the 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. Care must be taken to incorporate thorough analysis of the impacts of uncertainty in these estimators in assessing reliability impacts.

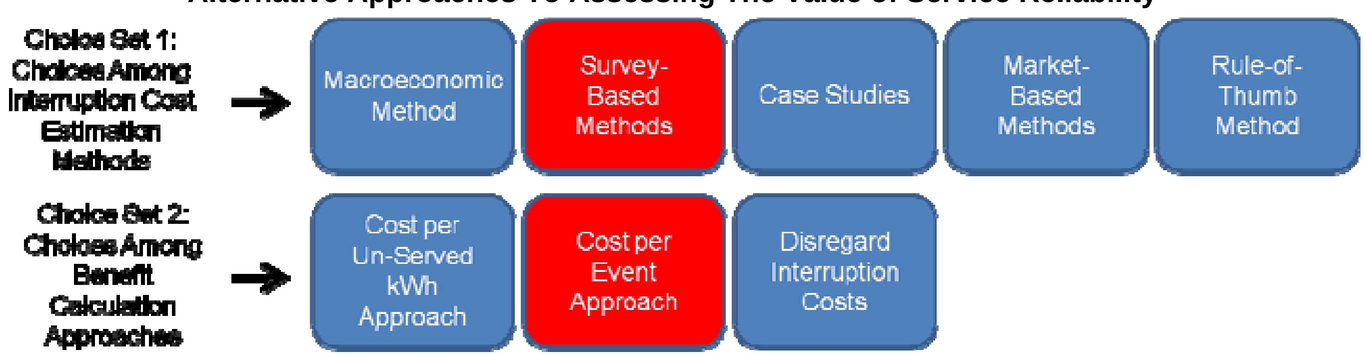
Even more serious problems can arise in making *ex ante* projections of the impacts of reliability investments on reliability. In making ex ante projections of reliability indicators it is necessary to *forecast* future reliability either by simulating the performance of the subject system (e.g., circuit 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 paper does not provide guidance concerning the evaluation of approaches used to analyze and project reliability; and to our knowledge there is no standard practice in the industry that serves as a reasonable guide for such analysis. It is obvious that 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.

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 average interruption cost estimates from the different estimation methods can vary by as much as a factor of 10. This document discusses the methods that have been used to estimate interruption costs and recommends a specific approach (survey based methods) that has been adopted in most recent studies of the economic value of reliability.

Figure 1-3 displays the distribution of choices that are available for assessing the economic value of reliability investments. There are basically five alternatives available for estimating interruption costs; and three alternatives available for quantifying reliability impacts of investments. It is possible to mix and match from these two choice sets. Indeed, the literature provides evidence of utilities having chosen almost every combination at one time or another.

It is our view that the choices among these analysis alternatives are not arbitrary. The remainder of this report discusses the consequences of selecting different choice alternatives and eventually recommends the choice set highlighted in red in Figure 1-3. Section 2 discusses the strengths and weaknesses of the 5 interruption cost estimation methods. Section 3 discusses the strengths and weaknesses of the 3 approaches for calculating reliability benefits. Section 4 discusses studies that incorporate reliability benefits. In Section 5, our recommendations among these choices are discussed. Finally, Section 6 provides a bibliography.

Figure 1-3:
Alternative Approaches To Assessing The Value of Service Reliability



2 METHODS FOR ESTIMATING INTERRUPTION COSTS

Researchers have used various methods for estimating the customer benefits associated with reliability improvements. These methods focus on estimating interruption costs – the cost of unreliability – because value of service reliability is difficult (if not impossible) to measure directly (Billinton et al., 1993).

Table 2-1 summarizes the 5 methods that have been used to estimate interruption costs. These methods include:

- The use of macroeconomic indicators (e.g., GDP);
- Customer survey based estimates (e.g., customer outage cost surveys);
- Case study estimates (e.g., New York blackout);
- Market based methods (e.g., amounts paid for backup generation); and
- Rule-of-thumb method (e.g. undocumented costs).

Table 2-1:
Strengths and Weaknesses of Interruption Cost Estimation Methods

Methodology	Strengths	Weaknesses
Macroeconomic Method	▪ Inexpensive	▪ Unrealistic assumptions
Survey-Based Methods	▪ More accurate ▪ Applicable to many geographical areas and interruption scenarios	▪ Costly ▪ Responses are based on hypothetical scenarios
Case Studies	▪ Responses are based on actual interruptions	▪ Costly ▪ Major blackouts are not representative of normal conditions
Market-Based Methods	▪ Less costly than surveys	▪ Unrealistic assumptions
Rule-of-Thumb Method	▪ Inexpensive	▪ Outdated estimates ▪ Accuracy unknown

Each of these methods has strengths and weaknesses. On balance, the comparisons favor the use of survey based interruption cost estimates wherever possible.

The macroeconomic method is inexpensive, but relies on very tenuous assumptions about the relationship between broad based market indicators and customer interruption costs. There are numerous reasons why these assumptions are invalid that are discussed below.

Survey-based methods are costly, but are designed to collect reported interruption costs from customers – parties who should have the most accurate and reliable information concerning the costs their homes and businesses experience as a result of electric 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 most qualified to estimate their interruption costs; and in part it is because 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. That is, they do not ask customers about costs they have experienced, but instead ask customers about costs they think they *would* experience. 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.

Like the survey based methods, case studies of major blackouts ask customers to estimate the costs they experience – but instead of asking about the costs of hypothetical outages, case study surveys ask about the costs of *actual* blackouts. This approach avoids the criticism that the outages that customers are responding to are hypothetical. Unfortunately, a major weakness of case study estimates of interruption costs is that blackouts are not at all like the kinds of service interruptions that normally occur in utility operations. They generally last longer, are more geographically widespread and may result in significant societal costs (e.g., looting, rioting) that do not occur during normal interruptions. Correspondingly, it is hard to argue that the costs reported for these catastrophic conditions are applicable to the thousands of routine outages that occur several times per year for most customers and last one to four hours.

Like the macroeconomic method, market-based methods are less costly than surveys but rely on unrealistic assumptions about the relationship between market indicators and interruption costs. For C&I customers, estimates of interruption costs have been derived from data on backup generation purchases and interruptible rate enrollment. Market-based methods have not been used for residential customers.

The rule-of-thumb method is the least expensive way to estimate interruption costs. Some researchers rely on the same cost per un-served kWh estimates that have been used in the industry for decades, often without citing a source from which the estimates come. This method is insufficient because the interruption cost estimates are either outdated or their accuracy is unknown.

The remainder of this section provides a more detailed review of the literature concerning the five different methods for estimating interruption costs. The literature review focuses on outage cost estimation procedures that have been in use during the past 20 years and as such is not comprehensive of the work that was done during the period preceding 1990. For a comprehensive bibliography of pre-1990 interruption cost studies, see Tollefson et al. (1991) and Billinton et al. (1983).

2.1 Macroeconomic Method

The earliest efforts to estimate interruption costs relied on readily-available macroeconomic indicators – what one might think of as outage cost proxies. The earliest work, by Shipley et al. (1972) divided gross national product (GNP) by total electricity usage in the United States to estimate an interruption cost of about $2.50 per un-served kWh *in 2010 dollars*. At the time, the authors acknowledged that this method probably produced "very rough" estimates of interruption costs and hoped the paper stimulated more research. Other studies subsequently applied this method to smaller geographical areas (Telson, 1975), to C&I customers (Munasinghe, 1981) and to residential customers (Munasinghe, 1980; Gilmer and Mack, 1983).

The assumption that cost per un-served kWh equals GNP divided by total electricity usage is unreasonable. GNP is the market value of all goods and services made in a country in a given year. It doesn't correlate very strongly with customer interruption costs for a number of reasons. First, it is intuitively obvious and scientifically demonstrable that the timing of an outage strongly influences its cost. The ratio of GNP to annual electricity consumption is insensitive to the variation in the timing of outages. Then there is the fact that interruptions result in costs that are not counted in the value of goods and services. Outages result in damage to equipment, in restart costs and in the cost of additional labor required to recover production. None of these cost elements are included in GNP (Sullivan and Keane, 1995). There is also the issue of how the ratio measures the economic impact of outages on residential customers. Residential customers are not *producers* in the context of the GNP. So application of this metric to their interruption costs makes no logical sense at all. Finally, dividing GNP by kWh results in *significantly* lower interruption cost estimates on the average compared to results obtained from scientifically rigorous customer surveys. As discussed below, survey-based methods have estimated interruption costs that are 4 or 5 times larger on the average than $2.50 per un-served kWh obtained using this proxy indicator.

Nevertheless, applications of macroeconomic proxy indicators persist. More recently, the macroeconomic method for estimating interruption costs has been primarily applied in studies outside of North America. Tishler (1993) uses industry statistics to estimate the value of lost production for C&I customers in Israel. Using a similar methodology, Chen and Vella (1994) and Hsu et al. (1994) estimate interruption costs in Taiwan and Wijayatunga and Jayalath (2004) in South Asia. As recently as 2007, De Nooij et al. used the macroeconomic method to estimate interruption costs in the Netherlands. Most of the authors of these studies say that they are applying macroeconomic indicators of interruption costs to reliability planning assessments because they do not have other, more robust estimates of interruption costs. They often cite the high cost of survey-based methods as justification for using this method. Considering the substantial theoretical problems associated with the application of proxy measurements to the estimation of interruption costs, their use for this purpose should be avoided.

2.2 Survey-Based Methods

Customer interruption cost surveys can be relatively expensive – costing in the hundreds of thousands of dollars. Nevertheless, survey-based approaches to the estimation of customer interruption costs have been used on numerous occasions in North America during the past 20 years.

The principal reason for the widespread use of surveying to estimate customer interruption costs is that, as Billinton et al. (1993) indicated:

> "The customer survey approach has the distinct advantage in that the customer is in the best position to assess the costs associated with his condition and experience."

In addition to content validity, an important advantage of survey-based outage cost estimation methods is that they can be used to study a wide range of possible conditions under which interruptions might occur. Using survey questions concerning what would happen in the event of *hypothetical* interruptions, researchers can ask customers to estimate interruption costs they believe they would experience under a wide variety of conditions (i.e., outages occurring at different times of day, with varying interruption durations, outages with and without advance notice, etc.) In a typical interruption cost survey, customers are presented with 3-8 scenarios and asked the costs they believe will occur for the specific conditions described in each scenario (Sullivan and Keane, 1995). Since this survey data is collected at the individual customer level, these studies can be used to observe how interruption costs vary according to outage conditions and customer characteristics. Using this information, it is then possible to apply the results of interruption cost surveys to a wide range of conditions that may occur in utility planning (e.g., the average outage cost over a 24-hour day, day time outages, night time outages, etc.).

Another important advantage of survey-based methods is that scientific sampling techniques can be used to ensure that answers obtained from surveys are representative of the customer populations of interest. In this way, one can be assured that customer interruption cost estimates are representative of the broader utility populations of interest – and not just the customers who may have experienced a particular outage. However, because survey-based methods almost always have been targeted at representative samples of specific utilities, there has been resistance to applying interruption costs from one utility to another. Utility planners and regulators have generally responded to this concern by requiring periodic *utility specific* customer value of service studies. These studies are routinely called for by the California Public Utilities Commission; most other jurisdictions do not require them.

Although survey-based methods have been frequently applied in studies of customer outage costs in North America, there are some criticisms of this approach. Many of these criticisms apply to survey research in general, especially when responses are based on hypothetical questions.

In particular, it has been argued that customers who are unfamiliar with electric outages may have difficulty providing accurate estimates of the costs they would experience in electric outages. For example, De Nooij et al. (2007) argue that respondents may have difficultly accurately estimating costs if they rarely experience power interruptions. Anderson and Taylor (1986) argue that if a survey respondent has not experienced an interruption for a relatively long period of time, that they may overestimate interruption costs because they are unfamiliar with the ways in which costs can be mitigated.

Woo and Train (1988) tested this hypothesis and concluded that commercial customers *with* interruption experience provided less *variable* outage cost estimates than those without experience. However, because of the inherent variation in interruption cost estimates, the sample sizes were not large enough to detect a statistically significant difference between the interruption costs obtained from the two groups. It has to be said that while the accuracy of interruption-cost estimates obtained using hypothetical questions on surveys remains to be demonstrated, the critics of this approach have so far failed to provide conclusive evidence that bias is present. Nevertheless, the accuracy of this estimation technique should be investigated further.

To compensate for lack of context that customers may experience when asked about hypothetical interruption cost scenarios, researchers have developed survey designs that are intended to help respondents estimate their interruption costs. They provide example calculations and tables that are designed to guide customers through the outage cost estimation process. However, critics argue that because these survey aids can lead to different interruption cost estimates (Sanghvi, 1982) than would otherwise occur, there is the potential for these survey design features to cause bias. Again, no systematic evidence has been offered to suggest that this hypothesis is true and while arguments about the validity of survey measurements are far from settled, it seems clear that alternative measurement strategies offer little hope of producing more accurate or valid measurements than can be obtained through surveying.

In interpreting interruption cost survey results, it is important to keep in mind that there are four basic ways of estimating interruption costs using surveys. They are:

- Direct cost measurement techniques;
- Willingness-to-pay (WTP) techniques;
- Willingness-to-accept (WTA) techniques; and
- Conjoint surveys.

For studies of commercial and industrial customer outage costs, researchers almost always employed direct cost measurement techniques. Studies of residential interruption costs have used all four of the techniques cited above.

2.2.1 Direct Cost Measurement

Direct cost measurement has been used to study interruption costs for commercial and industrial customers because it is thought that these customers experience mostly tangible economic damage during outages that researchers can directly ask about on a survey. As suggested by Sullivan and Keane (1995), outage cost surveys for C&I customers typically ask customers to estimate their costs for the following cost components:

- Lost production or sales that can never be recovered;
- Labor costs (including overtime) to make up lost production or sales;
- Damage to materials and equipment;
- Other tangible costs such as the cost to run backup generation; and
- Intangible costs such as inconvenience to customers.

Savings due to production that was made up are usually subtracted from the sum of the above costs to arrive at the final interruption cost estimate. Considering that most C&I customers have a thorough understanding of their operating costs as well as experience with production interference resulting from all kinds of factors, direct cost estimates are believed to be accurate, even though they are based on hypothetical interruption scenarios. There have been a few efforts to study both direct cost measurement and WTP surveys applied to the same C&I customers. In these studies, customer willingness to pay was found to be substantially less than the estimated direct cost of outages. There are several possible explanations for this finding. It may represent strategic bias in the answers given by C&I customers. That is, they may low-ball the estimate of their WTP answers assuming the utility may raise electricity prices if they provide an accurate estimate. It may also occur because customers either underestimate the likelihood that they will experience interruptions or because they heavily discount the savings from avoided interruption costs in the future.

2.2.2 WTP/WTA Surveys

WTP or WTA survey designs are considered to be preferable to direct cost measurements for residential customer outage costs because it is difficult for customers to assign a direct cost to lost leisure time – a substantial fraction of the cost they experience as a result of electric outages. It is also difficult to take account of improvements customers may receive in welfare when they experience direct costs resulting from outages. For example, people often say that they will dine out if an outage occurs during the dinner hour and provide a direct cost for this expenditure. Since this substitution implies a change in the value they receive from their expenditure, it is difficult to assess the incremental change in welfare that results using a direct cost measurement. In a WTP survey, respondents report how much money they would be willing to pay to avoid interruptions of different kinds. WTA surveys ask respondents to report how much money they would be willing to accept to be subjected to each interruption scenario. According to economic theory, WTP and WTA responses should be the same (Willig, 1976). In practice, WTP responses are substantially lower than WTA responses because of asymmetry between how much customers value a loss versus a gain and preference for the status quo (Doane et al., 1988). In some interruption cost studies, residential interruption costs are estimated as the average of WTP and WTA measurements obtained from the same customers.

2.2.3 Conjoint Surveys

Conjoint surveys are similar to WTP/WTA surveys in that they attempt to measure how much customers are willing to pay to avoid interruptions of certain kinds. However, instead of asking about their willingness to pay to avoid a specific interruption scenario, respondents are asked to choose between varying electric bills that are associated with different described reliability conditions (number of extended outages of a certain duration). The main advantage of this method is that respondents are asked to choose between a realistic range of service and pricing options, whereas WTP/WTA surveys present open-ended questions about amounts customers might be willing to pay (Beenstock et al., 1998).

Beenstock et al. (1998) applied a conjoint survey design to a sample of 1,350 households in Israel and compared the results to those of a WTP/WTA survey. In the conjoint analysis, they asked respondents to rank six combinations of electric bills and service reliability levels. Using a conditional logit model, they estimated an interruption cost of $9 per un-served kWh among residential customers – an estimate that is 5 times larger than the estimate from their measurements based on WTP/WTA survey responses.

A possible explanation for the differences that were observed between willingness to pay measurements and those obtained through conjoint analysis is the use of ranked responses as a measure of interruption costs. In analyzing this problem, Goett et al. (1988) concluded that ranked responses led to biased estimates in the logit model because of econometric issues involved with converting rankings to cost estimates. Despite this possible problem, researchers continue to try to apply conjoint survey techniques using ranking. For example, see Baarsma and Hop (2009). This problem bares further investigation and until the issue is resolved conjoint methods for estimating customer interruption costs should be avoided.

2.3 Case Studies

A few case studies have been conducted after major blackouts that affected millions of customers. Corwin and Miles (1978) assessed the 1977 New York City blackout and found that there were substantial indirect damages from arson, looting and rioting. In total, they estimated an aggregate cost of $345 million. They treated the analysis as if the 25-hour interruption were a natural disaster like an earthquake or a hurricane. In this context, much of the indirect cost was incurred by the government in the form of law enforcement and assistance programs to clean up after the disaster.

Other case studies of major blackouts have taken a more conventional survey-based approach. After the August 1996 blackouts in Western states, the California Energy Commission (1997) surveyed residential and C&I customers on the damages that they experienced. They found that interruption costs varied substantially. Most customers did not experience any financial losses whereas some C&I customers experienced direct costs between $50,000 and $5 million. Serra and Fierro (1997) used a similar survey methodology to measure the economic impact of electricity rationing in Chile.

The strength of case studies is that they are designed to estimate costs for outages that actually occurred rather than hypothetical outages. The weakness of this approach is that the outage for which cost estimates are obtained is nothing like the outages that frequently occur on utility systems – for which outage costs are needed. A major blackout is not representative of interruptions in general any more than the winds in a tornado are representative of the winds during an afternoon rainstorm. For example, the 1977 New York City blackout was a unique situation where a lightning strike unexpectedly brought down the electricity service for the entire city of New York for a period of 25 hours. From the utility's point of view, this blackout would be considered a major event and would normally be excluded from reliability indicators like SAIFI and SAIDI. With respect to Smart Grid benefits, a reduction in wide-scale blackouts is categorized as a security benefit as opposed to a reliability benefit.

Because the outages that are the subject of case studies are so different from outages that are the normal subject of utility planning, interruption costs from these studies are not recommended for evaluating the reliability impacts of Smart Grid investments.

2.4 Market-Based Methods

Researchers have estimated interruption costs using data on purchases of backup generation and subscriptions to interruptible rate options. Like the macroeconomic method, these data are relatively inexpensive to acquire. And like the macroeconomic method, estimates of interruption costs derived from this method rest on unrealistic assumptions.

In order to assume that the choices parties make in purchasing backup generation or subscribing to interruptible rates reflect the economic worth of reliability, it is necessary to assume that a broad range of backup generation and interruptible rate options are available to customers. In fact, interruptible rate options and backup generation alternatives are quite limited in performance and price.

2.4.1 Backup Generation Purchases

The assumption of this approach is that customers invest in backup generation to avoid interruptions just to the point at which the value of backup generation equals the economic cost of unreliability. Therefore, by analyzing data on backup generation purchases, interruption costs can be inferred. Bental and Ravid (1982) use this method to estimate interruptions costs for industrial customers in Israel. For large computer users in Japan, Matsukawa and Jujii (1994) also make use of data on backup generation purchases to infer interruption costs. The problem with this method is that customers do not often invest in backup generation in proportion to the costs that they experience as a result of unreliability. This occurs for various reasons unrelated to the value they assign to unreliability or the costs they experience on an annual basis because of it. For example, customers may not purchase backup generation because they cannot afford it, because corporate investment plans prohibit investments in the plant and so on. Investment decisions on the part of plant and facility managers are just not this simple and significant distortions in measurement are possible if they are used to estimate interruption costs.

2.4.2 Interruptible Rate Enrollment

A few efforts have been made to use subscription rates to interruptible rate options to infer customer interruption costs for certain classes of customers. For example, Caves et al. (1992) and Keane and Woo (1995) use subscriptions to interruptible rate options to estimate the value of service reliability for large industrial customers. This estimation procedure is based on the idea that customers will enroll in interruptible rate options if the marginal incentive for allowing the utility to interrupt service is greater than the customer's interruption cost. The problem with this logic is that there is only one discount level available to all customers and the *reliability advertised* for the interruptible program is dramatically lower than the *actual reliability* – and the customers believe this to be the case when they make their choice among reliability price alternatives. Correspondingly, interruption costs derived using this approach should not generally be used.

2.5 Rule of Thumb Method

A common rule of thumb for reliability planners is to use the following interruption cost estimates:

- Residential customers: $2.5 per un-served kWh;
- Commercial customers: $10 per un-served kWh; and
- Industrial customers: $25 per un-served kWh.

In reports that employ rules of thumb, sources of interruption cost estimates are generally not cited.[4] The California Energy Commission (2009) used these interruption cost estimates to calculate the reliability benefit associated with distribution automation in California. In other applications, other slightly different rules of thumb are used. Although the interruption cost estimates presented as rules of thumb have a substantial impact on the overall results, there is no discussion of why these estimates were chosen or a source to the study from which they came.

Measurements of the economic value of service reliability improvements derived from rules of thumb can result in wildly different interruption cost estimates from those that employ interruption cost estimates based on empirical research. For example, in the above referenced California Energy Commission study, researchers estimated that the maximum expected benefit from distribution automation was $292 million. Sullivan et al. (2009) show that cost per un-served kWh is substantially higher for commercial customers relative to industrial customers – contradicting the rule of thumb estimates used in the CEC estimate. Although industrial customers experience higher costs per customer, cost per un-served kWh is lower because electricity is a much larger component of their production cost than that of commercial customers.

Using the well documented and presumably much more accurate interruption cost estimates, Sullivan et al. (2010) estimate the reliability benefit to C&I customers associated with distribution automation in California to be nearly two times higher than the CEC study indicates. This example illustrates the folly of using rule of thumb estimates of interruption costs in valuing reliability improvements.

2.6 Recommendations for Estimating Interruption Costs

The literature and experience support the conclusion that interruption costs obtained from carefully conducted statistical surveys of representative samples of customers should be used to estimate interruption cost reductions associated with reliability improvements. These survey

[4] While the adoption of such rules of thumb seems completely arbitrary, it is really no different from adopting the common rule of thumb used in generation reliability planning that generation outages should not exceed 1 day in 10 years. This is not meant to lend legitimacy to the rule of thumb approach, but to suggest that rules of thumb are commonly used in utility planning.

results should be obtained using generally accepted survey procedures such as those outlined in *Interruption Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI. It is our understanding that such surveys have not been conducted by the utilities operating within the jurisdiction of the Illinois Commerce Commission.

Until such time as customer interruption costs can be estimated based on surveys of local utility customers, evaluations of the economic value of service reliability should rely on estimates obtained from a comprehensive analysis of customer-interruption costs that combined the results of 28 interruption-cost surveys to develop econometric models for projecting customer interruption costs. The research underlying the development of these models is found in: *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

3 APPROACHES TO CALCULATING RELIABILITY BENEFITS

Table 3-1 summarizes the strengths and weaknesses associated with the different approaches to calculating reliability benefits. The cost per un-served kWh approach is straightforward, but does not account for the differential impacts of interruption frequency and duration. The cost per event approach accounts for these differential impacts, which leads to more accurate calculations because they properly reflect customer preference for interruption frequency reductions relative to duration reductions.[5] The remainder of this section provides a more detailed review of the literature on the three different approaches for calculating reliability benefits once interruption costs have been estimated.

Table 3-1:
Strengths and Weaknesses of Benefit Calculation Approaches

Approach	Strengths	Weaknesses
1. Cost per Un-Served kWh Approach	▪ Straightforward	▪ Does not account for differential impacts of frequency and duration ▪ Less accurate
2. Cost per Event Approach	▪ Accounts for differential impacts of frequency and duration ▪ More accurate	▪ Slightly more complicated
3. Disregard Interruption Costs	▪ Convenient	▪ Unrealistic ▪ Overlooks important customer benefit

3.1 Cost per Un-Served kWh Approach

The most common approach for calculating reliability benefits is to apply the cost per un-served kWh from the interruption cost estimates. For sustained and major interruptions, EPRI (2010) suggests using the following equation for this approach:

$$\text{Benefit (\$)} = [\text{Interruption Duration (hours)} * \text{Load Not Served (kW estimated)} * \text{VOS (\$/kWh)}]_{\text{Baseline}} - [\text{Interruption Duration (hours)} * \text{Load Not Served (kW estimated)} * \text{VOS (\$/kWh)}]_{\text{Project}}$$

5 Section 2 reports many cost per un-served kWh estimates. This approach is helpful for comparing different interruption cost estimation methods, but is not recommended here as part of the final calculation of reliability benefits.

In the above equation:

- *Benefit* is the calculated reliability benefit with respect to sustained interruptions;
- *Baseline* represents the projected reliability conditions when there is no investment;
- *Project* represents the projected reliability conditions after the proposed investment;
- *Interruption Duration* is the estimated number of interrupted hours before and after the proposed investment;
- *Load Not Served* is the estimated aggregate kW not served during interrupted hours; and
- *VOS* is the cost per un-served kWh from the interruption cost estimates.

In practice, *Load Not Served* and *VOS* do not vary under the *Baseline* and *Project* scenarios. Therefore, the above equation can be rewritten as:

$$\text{Benefit (\$)} = \text{Load Not Served (kW estimated)} * \text{VOS (\$/kWh)} * [\text{Interruption Duration (hours)}_{\text{Baseline}} - \text{Interruption Duration (hours)}_{\text{Project}}]$$

As evidenced by this equation, benefits calculated from the cost per un-served kWh approach are a direct function of the change in the number of interrupted hours. Whether this change is a result of reduced interruption frequency or duration does not have an impact on the calculation. Although this approach is straightforward, it fails to account for the differential impacts of frequency and duration.

Failing to account for the differential impacts of frequency and duration can lead to highly inaccurate estimated benefits. To see why this is so, consider the following stylized example from Sullivan et al. (2010). There are two Smart Grid investments in consideration. One reduces interruption duration by 50%, and the other reduces 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, the average medium and large C&I customer experiences a single one-hour interruption each year. In Sullivan et al. (2009), this 1-hour interruption costs the average 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 average medium and large C&I customer still experiences 1 interruption per year, but this interruption now only lasts 30 minutes. This 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 interruption frequency will result in a situation where the average interruption duration is still 1-hour, but the probability of experiencing an interruption is reduced by 50%. Therefore, a 1-hour interruption still costs the customer $12,487, but since 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.

Although the cost per un-served kWh approach is inadequate, it is quite common in the literature. KEMA (2009) suggests that SAIDI is all that is needed to calculate benefits associated with a reduction in sustained interruptions. EPRI (2008) states that, "the total outage cost for a customer is estimated by multiplying frequency times duration to derive total hours of outage and then multiplying this by the VOLL for the total MW affected." Baer et al. (2004) estimate the total un-served kWh for residential, commercial and industrial customers in the United States and apply a cost per un-served kWh value to an assumed reduction in the number of interrupted hours. Although each of these studies addresses technologies that have differential impacts on the frequency and duration of sustained interruptions, the recommended approach is the same. It should be obvious that these recommendations are flawed.

3.2 Cost per Event Approach

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. Since this approach is slightly more complicated, the following equations use commonly reported utility metrics like SAIFI and CAIDI. For sustained interruptions, Sullivan et al. (2010) suggest using the following equation for the cost per event approach:

$$\text{Benefit (\$)} = N * [[\text{SAIFI} * \text{VOS (\$/event)}]_{\text{Baseline}} - [\text{SAIFI} * \text{VOS (\$/event)}]_{\text{Project}}]$$

In the above equation:

- *Benefit* is the calculated reliability benefit with respect to sustained interruptions;
- *Baseline* represents the projected reliability conditions when there is no investment;
- *Project* represents the projected reliability conditions after the proposed investment;
- *N* is the number of customers that benefit from the proposed investment;
- *SAIFI* is the estimated System Average Interruption Frequency Index before and after the proposed investment; and
- *VOS* is the estimated cost per interruption before and after the proposed investment.

If the average interruption duration changes as a result of the proposed investment, the cost per interruption varies between the *Baseline* and *Project* scenarios. Therefore, the *VOS* estimate per event is 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, as shown in the example in Section 3.1. Considering that many planners compare the benefits of investments that have differential impacts on frequency and duration, it is important to not just focus on the number of interrupted hours.

Although EPRI (2010) suggests the cost per un-served kWh approach for sustained interruptions, the report recommends the cost per event approach for calculating power quality benefits. For momentary interruptions, sags and swells, there is little to no un-served kWh so the cost per event approach is clearly preferable.

For momentary interruptions, the following equation can be used:

$$\text{Benefit (\$)} = N * \text{VOS (\$/event)} * [\text{MAIFI}_{\text{Baseline}} - \text{MAIFI}_{\text{Project}}]$$

For sags or swells, the following equation can be used:

$$\text{Benefit (\$)} = N * \text{VOS (\$/event)} * [\text{\# Sags/Swells}_{\text{Baseline}} - \text{\# Sags/Swells}_{\text{Project}}]$$

In the equation for sustained interruptions, cost per event changes in each scenario because duration changes. For momentary interruptions, sags and swells, the change in the number of events is the only driver of the benefits. *VOS* is the same in the *Project* and *Baseline* scenarios, which makes these equations simpler than the equation for sustained interruptions.

3.3 Disregard Reliability Benefits

After observing interruption cost estimates, many planners choose to disregard changes in interruption costs in their benefit calculations. Some planners take this stance because they believe that interruption cost estimates are inaccurate. For these planners, it is important to realize that although there is uncertainty associated with any interruption cost estimate, it is better to use the best estimate than to assume that interruption costs are zero. When planners disregard interruption cost, they are essentially assuming that interruption costs are zero, which is also an estimate and not a good one.

Other planners choose to disregard interruption costs because utilities do not directly benefit. For these planners, it is important to realize that interruption costs are an externality to the utility, much like the environmental benefits associated with Smart Grid investments, but they are not zero. Utilities do not directly benefit from reductions in air emissions, but are encouraged to consider these benefits because the costs of this externality are not accurately reflected in the market. The same thought process should be considered for interruption costs. Like any externality, there is uncertainty associated with their cost, but it is better to use the best estimate than to disregard them completely and essentially assume that there is no cost.

For power quality disturbances, it may be preferable to disregard the benefits until the cost estimates are analyzed in more detail and utility measurement metrics are standardized. Considering that sustained interruptions usually comprise the majority of reliability benefits, it is not that much of a drawback to disregard power quality disturbances for now. This approach is more preferable than relying on a biased estimate of power quality benefits that could significantly impact the results.

3.4 Recommendations for Calculating Reliability Benefits

For sustained interruptions, it is recommended that planners use the cost per event approach for calculating reliability benefits. This approach is more accurate and properly accounts for the differential impacts of interruption frequency and duration. For an example of this approach, see Appendix F in: *Benefit-Cost Analysis for Advanced Metering and Time-Based Pricing.* Prepared for Vermont Department of Public Service. A summary of this study is provided in Section 4.7.

For power quality disturbances, further research is necessary to determine whether or not the cost per event approach leads to accurate estimates of reliability benefits. The cost per un-served kWh approach does not apply because there is little to no un-served kWh during power quality disturbances. The ICC should open a discussion with stakeholder utilities to determine how power quality disturbances are measured and whether these measurements are accurate. Based on this discussion, a cost per event framework for estimating power quality benefits can be established.

4 STUDIES THAT INCORPORATE RELIABILITY BENEFITS

With an understanding of the higher level concepts in Sections 2 and 3, it is possible to accurately evaluate the strengths and weaknesses of specific studies that incorporate reliability benefits. In general, reliability benefits to the customer are not frequently estimated in planning studies. Most of these studies focus on benefits to the utility exclusively. When reliability benefits are estimated, studies frequently apply inaccurate and/or outdated interruption costs estimates and use variations of the cost per un-served kWh approach. In this section, studies of specific investments in generation, transmission and distribution are summarized and the strengths and weakness of each are discussed. The study of advanced metering infrastructure (AMI) by George et al. (2008) is the closest representation of what is recommended. Although this study relies on relatively simplistic forecasts of SAIFI and CAIDI with and without AMI, the general approach is a good example of how to estimate reliability benefits to the customer. The study on transmission planning at Duke Energy by Dalton et al. (1996) is a good example of how VBRP can be applied within a utility, but detailed information on the methods used is not provided.

4.1 Generation Reserve Margin

Billinton and Allan (1996) provide an example of a value-based reliability planning approach to determining the optimal investment in generation reserves for a service area with a system peak forecast of 170 MW. Using industry-specific interruption cost estimates from a Canadian interruption cost survey, they estimate the cost per unserved kWh for the service area at varying durations (see Table 4-1). In order to calculate the cost per unserved kWh for the whole service area, they weight each industry-specific interruption cost estimate by the total quantity of kWh sold to customers in each industry. Using a weighted cost per unserved kWh value customizes the interruption cost estimates in the survey for the industry mix of businesses in the service area being studied. Based on these interruption costs for varying durations, they estimate a cost per un-served kWh of $3.83 (1996). The aggregate interruption cost for each scenario can then be calculated by multiplying the estimated un-served energy for each scenario by the cost per un-served kWh.

Table 4-1:
Interruption Cost Estimates Used in Billinton and Allan (1996)

Interruption Duration	Interruption Cost ($/kW)
1 minute	0.67
20 minutes	1.56
2 hours	3.85
4 hours	12.14
8 hours	29.41

Table 4-2 shows the results of their case 1 analysis.[6] For this case, it is assumed that forecasted peak demand is 170 MW and total generation capacity without any additional reserves is 200 MW. The study estimates the total cost associated with adding up to 5, 10 MW gas turbine units to the system. The total cost is the sum of interruption costs and the cost of additional capacity. Each gas turbine has an annual fixed cost of $500,000. Although a single type of investment is being investigated (additional reserve capacity), the 5 alternative scenarios represent different levels of investment (10 to 50 MW of additional reserve capacity depending on the number of gas turbines purchased). As additional reserve capacity increases, the fixed cost of additional capacity increases while estimated un-served energy and interruption costs decrease. For this case, total cost reaches a minimum at 10 MW of additional reserve capacity, which is the optimal level of investment that should be made.

Table 4-2:
Case 1 Results from Billinton and Allan (1996)

Additional Reserve Capacity (MW)	Total Capacity (MW)	Reserve Margin (%)	Estimated Un-Served Energy (MWh/year)	Estimated Interruption Cost ($M/year)	Fixed Cost of Additional Capacity ($M/year)	Total Cost ($M/year)
0	200	17.7	313.9	1.202	0.0	1.202
10	210	23.5	74.3	0.284	0.5	0.784
20	220	29.4	40.9	0.157	1.0	1.157
30	230	35.3	19.5	0.075	1.5	1.575
40	240	41.2	6.3	0.024	2.0	2.024
50	250	47.1	1.2	0.004	2.5	2.504

The use of survey-based interruption cost estimates and the customization of these estimates to a given service area are strengths of this study. A weakness of this study is that it uses a cost per un-served kWh approach for calculating reliability benefits. Although interruption costs are estimated for varying durations, this information is oversimplified into a single cost per un-served kWh estimate of $3.83. This approach is oversimplified because it does not account for the differential impacts of frequency and duration. The study does not indicate whether the estimated decrease in un-served energy results from an interruption frequency or duration reduction. If additional reserve capacity reduces frequency relatively more, the associated reduction in interruption cost will be relatively higher. If the estimated un-served energy decreases because of shorter duration, the reduction in interruption cost will be relatively lower.

[6] Three other cases with different assumptions were analyzed in this study. Since the method is the same for all 4 cases, we only present the results from case 1.

Each additional reserve capacity scenario has an associated frequency and duration of interruptions. It is simpler, but not recommended, to bundle the two factors into a single un-served energy estimate and multiply it by a constant cost per un-served kWh estimate.

4.2 Transmission Planning

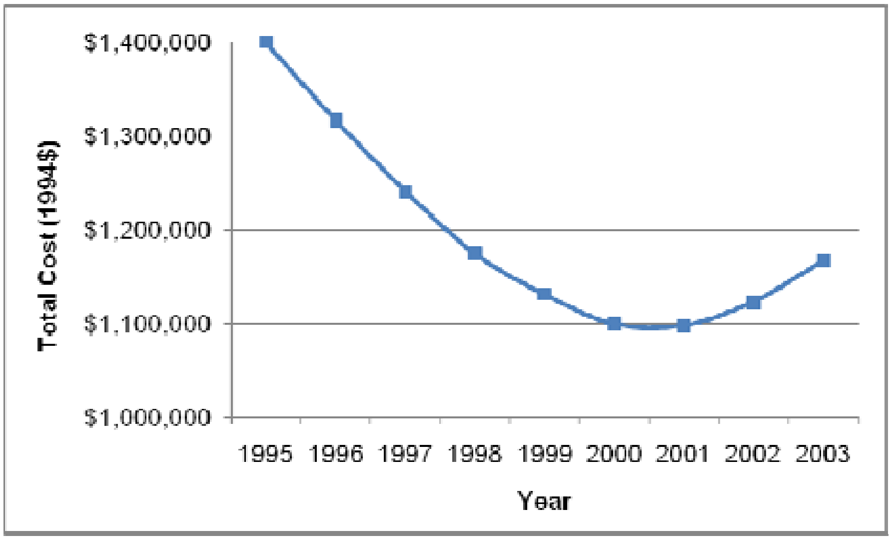
Dalton et al. (1996) provide an example of incorporating reliability benefits to the customer in transmission planning. This study concisely summarizes Duke's motivation for applying VBRP to its transmission system:

> "In the past, any single contingency that could occur during system peak conditions and cause a thermal overload required the overloaded facility to be upgraded, regardless of the costs or the likelihood of the overload occurring ... The new process attempts to balance the costs of improving service reliability with the benefits or value that these improvements bring to these customers."

This study analyzes two adjacent parallel transmission lines. At system peak, load flow studies indicate that either line would be overloaded if the other was forced out. Therefore, the deterministic rule of thumb that was currently in place would require Duke to upgrade the lines immediately at a cost of $1,400,000. However, given the small likelihood of an outage, customer interruption costs did not exceed the cost of the investment. Over time, the likelihood of an outage increases and customer interruption costs eventually outweigh the cost of the upgrade. The key to this study was to determine the optimal year of investment where total costs are minimized.

The study briefly indicates that it uses survey-based interruption cost estimates and calculates reliability benefits using the cost per event approach based on the frequency and duration of interruptions. The interruption cost estimates in each year are added to the cost of the investment to calculate the total cost associated with the transmission lines. Figure 4-1 shows how this total cost changes from 1995 to 2003. As time passes, interruption costs increase because of reliability degradation (caused by load growth) and the investment cost decreases because of the time value of money. Before 2001, the value associated with deferring the investment is greater than interruption costs. After 2001, reliability degrades to a point where interruption costs outweigh the benefits associated with deferring the investment. Total cost reaches a minimum in 2001, which is when the VBRP approach suggests the investment should be made. If the investment is made in 2001 as opposed to 1995, the utility and its customers will save $300,000 because a VBRP approach was used as opposed to the rule of thumb that was in place.

Figure 4-1:
Determining the Optimal Year for a Transmission Line Upgrade
Results from Dalton et al. (1996)



Two strengths of this study are that it uses survey-based interruption cost estimates and the cost per event approach for calculating reliability benefits. It is difficult to assess the weakness of this study because few details on the methodology are provided. Nonetheless, it is a good example of how VBRP can be applied to transmission planning within a utility.

4.3 Alternative Distribution Configurations

Billinton and Allan (1996) also use a VBRP approach for determining optimal distribution configuration. There are four cases described in this study:

- Case 1: Base case with no change in configuration;
- Case 2: Configuration that includes lateral distribution line protection;
- Case 3: Configuration that adds disconnects in the main feeder; and
- Case 4: Configuration that transfers load to an adjacent feeder.

For each case, they estimate un-served energy based on an analysis of the impact of each distribution configuration on the frequency and duration of interruptions at each load point on the feeder. By multiplying interruption frequency by duration, the total number of interrupted hours for each case and load point is estimated. This estimate of interrupted hours is multiplied by the aggregate kW at each load point to arrive at an un-served energy estimate. As in the analysis of varying generation reserve margins (Section 4.1.1), they use an interruption cost estimate of $3.83 per un-served kWh. Finally, they calculate interruption costs for each case and load point by multiplying the un-served energy estimate by the cost per un-served kWh. The aggregate interruption cost for each case is the sum of estimated costs across the four load points.

Table 4-3 summarizes the results from this analysis. Case 4 results in the lowest un-served energy and aggregate interruption cost. However, this finding does not necessarily mean that the configuration that transfers load to an adjacent feeder (case 4) is economically optimal. It just means that this alternative produces the lowest interruption cost. The investment cost associated with each case would have to be estimated in order to determine which distribution configuration is economically optimal. By adding this investment cost to the aggregate interruption cost for each case, the optimal distribution configuration that minimizes total costs could be determined.

Table 4-3:
Case 1-4 Results from Billinton and Allan (1996)

Case	Estimated Interruption Cost ($k/year)					Estimated Un-Served Energy (MWh/year)
	Load Point A	*Load Point B*	*Load Point C*	*Load Point D*	*Aggregate*	
1	114.9	92.0	69.0	46.0	321.8	84.0
2	69.5	67.7	46.2	27.8	211.2	54.8
3	28.6	40.5	39.1	27.8	136.0	35.2
4	28.6	29.6	25.8	11.5	95.5	25.1

As in the analysis of varying generation reserve margins (Section 4.1.1), a strength of this study is the use of survey-based interruption cost estimates and a weakness is that it employs a cost per un-served kWh approach for calculating reliability benefits. Although they forecast the impact of each distribution configuration on the frequency and duration of interruptions, these factors are multiplied together to arrive at a total number of interrupted hours. Instead of analyzing frequency and duration separately, the interruption cost is estimated from the number of interrupted hours. This method is not recommended, especially when forecasts of interruption frequency and duration for each alternative investment are readily available.

4.4 Alternative Feed to a City

Chowdhury and Koval (2009) estimate the reliability benefits associated with the provision of an alternative feed to a city with a population of approximately 25,000 people. In this city, planning criteria dictate that 80% of the city must receive backup supply. The alternative feed is expected to reduce the number of interrupted hours by 4 hours per year. Here are the steps they use to calculate the expected annual reliability benefit:

1. Current annual supply unavailability 5 hours/year
2. Switching time for alternative feed 1 hour
3. Expected reduction in interrupted hours 5 hours - 1 hour = 4 hours

4.	Un-served load	10 MW
5.	Load factor	85%
6.	Expected un-served energy avoided	10 MW x 0.85 x 0.80[7] x 4 = 27.2 MWh
7.	Customer interruption cost	$14/kWh
8.	Expected annual reliability benefit	$14,000 x 27.2 MWh = $380,800 per year

By including the annual cost of providing an alternative feed to the city, the cost-effectiveness of the investment could be determined, *but this was not done*. In this scenario, it may or may not be cost-effective to provide 80% of the city with backup supply. This analysis would suggest whether or not the planning criteria accurately reflect costs.

The expected reduction in un-served energy (step 6) is a function of the reduction in interrupted hours and expected load. When multiplied by the estimated customer interruption cost in step 8, they arrive at an expected annual reliability benefit of $380,800. A notable flaw in this analysis is that the source of the interruption cost estimate is not provided. As previously explained, reliance on undocumented interruption cost estimates can lead to great uncertainty about the validity of the conclusions drawn from such a study.

This example also highlights another issue with ignoring interruption frequency when calculating reliability benefits. Step 1 does not indicate the frequency of interruptions that result in the 5 hours of unavailable supply per year. By ignoring interruption frequency, step 3 overlooks that there should be an hour of switching time for each interruption. The results of this analysis will vary substantially depending on interruption frequency. In fact, the alternative feed will provide no benefit if there are five or more interruptions per year because the switching time is too long to provide any backup supply with an average interruption duration of one hour or less. The results presume that there is one interruption per year. If this is true, the estimated avoided interruption cost may be correct (taking for granted the validity of the interruption cost estimates), if not the avoided interruption cost estimate may be seriously overestimated.

[7] This number adjusts the result for the fact that only 80% of the city will receive backup supply through the alternative feed, not the entire city.

4.5 Substation Capacity and Feeder Sectionalizing

In another example, Chowdhury and Koval (2009) demonstrate a useful variation of the cost per event approach for calculating reliability benefits. In their example, planners must choose between varying substation capacities and types of feeder sectionalizing. There are two substations in this study. Substation A can have a capacity of 10 or 20 MVA. Substation B can have a capacity of 7.5 or 17.5 MVA. The type of feeder sectionalizing can either be manual or automatic. The study considers three investment scenarios:

- Case 1: Substation A=10 MVA, Substation B=7.5 MVA, Manual Feeder Sectionalizing;
- Case 2: Substation A=20 MVA, Substation B=17.5 MVA, Manual Feeder Sectionalizing; and
- Case 3: Substation A=20 MVA, Substation B=17.5 MVA, Automatic Feeder Sectionalizing.

There are seven load points on the feeder (A through G). For this summary, load point E is used to demonstrate their approach. The approach is the same for all load points.

For this study, the estimated interruption cost is $9.62/average kW for a 1-hour interruption and $18.544/average kW for a 4-hour interruption. Each of the four sections within each load point is assigned an interruption duration of 0, 1 or 4 hours. As shown in Table 4-4, case 1 results for load point E estimate a 4-hour average interruption duration for sections 1 and 4 and a 1-hour duration for sections 2 and 3. Case 2 results in a 3-hour reduction in average interruption duration for section 4, from four hours to one hour. Case 3 is similar to case 2 except that there are no interruptions for sections 2 and 3 (i.e., average interruption duration is zero). For each case, the associated $/average kW estimate is assigned to each section depending on the average interruption duration (0 hour=$0/average kW; 1 hour=$9.62/average kW; and 4 hours=$18.544/average kW). This estimate is multiplied by the load for each section to arrive at the interruption cost. The aggregate annual interruption cost for each case is the sum of estimated costs across the four sections.

Table 4-4 summarizes the results from this analysis. Not surprisingly, Case 3 results in the lowest aggregate annual interruption cost. However, it is to be expected that more substation capacity and automatic feeder sectionalizing will lead to lower interruption costs. The question is: are these reductions in interruption costs justifiable in light of the investment costs required to achieve them. In order to determine the cost effectiveness of these investment alternatives, the investment cost associated with each case would have to be estimated.

Table 4-4:
Results for Load Point E in Chowdhury and Koval (2009)

Section Number	Length (km)	Interruptions per Year	Average Interruption Duration	Aggregate Load (kW)	Estimated Interruption Cost ($/kW)	Aggregate Annual Interruption Cost ($k/year)
Case 1: Substation A=10 MVA, Substation B=7.5 MVA, Manual Feeder Sectionalizing						
1	6	0.10	4.0	2468.6	18.544	4.6
2	3	0.15	1.0	2468.6	9.62	3.6
3	4	0.20	1.0	2468.6	9.62	4.7
4	16	0.80	4.0	2468.6	18.544	36.6
					Total:	**49.5**
Case 2: Substation A=20 MVA, Substation B=17.5 MVA, Manual Feeder Sectionalizing						
1	6	0.10	4.0	2468.6	18.544	4.6
2	3	0.15	1.0	2468.6	9.62	3.6
3	4	0.20	1.0	2468.6	9.62	4.7
4	16	0.80	1.0	2468.6	9.62	19.0
					Total:	**31.9**
Case 3: Substation A=20 MVA, Substation B=17.5 MVA, Automatic Feeder Sectionalizing						
1	6	0.10	4.0	2468.6	18.544	4.6
2	3	0.00	0.0	2468.6	0.00	0.0
3	4	0.00	0.0	2468.6	0.00	0.0
4	16	0.80	1.0	2468.6	9.62	19.0
					Total:	**23.6**

As discussed in Section 3, It is recommended that planners use the cost per event approach for calculating reliability benefits. This approach is demonstrated in this example. As shown in Table 4-4, each average interruption duration has an associated interruption cost estimate. Therefore, this study first estimates the average cost associated with the expected interruption for each section based on CAIDI. Then, this estimate is adjusted for the likelihood that an interruption occurs in a given year (SAIFI). Instead of multiplying this result by the number of customers, it is scaled to the total annual cost by the aggregate load since the interruption cost estimates are in units of $/kW for each event. If the interruption cost estimates were in units of $/customer for each event, total annual cost would be determined by multiplying by the number of customers instead.

One weakness of this study is that it relies on only two estimates of cost per average kW. Each section within each load point is assigned an interruption duration of 0, 1 or 4 hours. It is unclear if this study is a stylized example or if they use actual data on interruption durations and simply round each observation to 0, 1 or 4 hours. If it is a stylized example, the method is not applicable because interruption duration is a continuous variable. If this study uses rounded estimates of interruption duration from actual data, the method is inaccurate because there is a lot of important variation between 0, 1 and 4 hours. Instead of rounding to the duration of the nearest interruption cost estimate, it is recommended that planners build a relatively simple excel-based model that estimates costs for any duration.

4.6 Distribution Automation

As noted in Section 2.5, the California Energy Commission (2009) estimated the reliability benefit associated with distribution automation in California. They used the following interruption cost estimates:

- Residential customers: $2.5 per un-served kWh;
- Commercial customers: $10 per un-served kWh; and
- Industrial customers: $25 per un-served kWh.

As a result of distribution automation in California, they estimate a 32.7% reduction in SAIFI from 1.066 to 0.781. With a CAIDI of 101.9 minutes, the SAIFI reduction results in a 35-minute reduction in SAIDI. The reduction in interrupted hours in Table 4-5 is calculated for each sector by multiplying the SAIDI reduction by the number of customers and dividing by 60. For each sector, the reduction in interrupted hours is multiplied by the average load and estimated interruption cost per un-served kWh to arrive at the estimated annual reliability benefit. The total reliability benefit is the sum of the three sectors. In total, the estimated annual reliability benefit to customers as a result of distribution automation is $127.7 million, most of which comes from the industrial sector. To determine whether this investment is cost-effective, the reliability benefit is combined with all of the other benefits of distribution automation and compared to the cost.

Table 4-5:
Results from California Energy Commission (2009)

Sector	Number of Customers	Reduction in Interrupted Hours	Average Load (kW)	Reduction in Un-served Energy (kWh)	Estimated Interruption Cost ($/kWh)	Estimated Annual Reliability Benefit ($M)
Residential	3,222,048	1,891,691	0.75	1,422,990	$2.5	$3.6
Commercial	429,955	252,430	6.56	1,655,688	$10	$17.8
Industrial	13,090	7,685	560	4,305,287	$25	$107.6
					Total:	**$127.7**

A strength of this study is that it employs readily available reliability indices – SAIFI, CAIDI and SAIDI. This makes it easier to replicate the approach in other jurisdictions and accurately compare the results. In addition, the use of these metrics may make it easier to communicate the results to those in the industry.

The key weakness of this study is that it relies on a rule of thumb for the interruption cost estimates. Although the interruption cost estimates have a substantial impact on the overall results, there is no discussion of why these estimates were chosen or a source to the study from which they came. To demonstrate the impact of applying updated and more accurate interruption cost estimates, Sullivan et al. (2010) also estimate the reliability benefit associated with distribution automation in California. Their estimated reliability benefit for C&I customers is nearly two times larger. Estimated reliability benefits are highly sensitive to the cost per un-served kWh estimates that planners use. Therefore, it is important to apply updated and accurate interruption cost estimates and not resort to using an outdated rule of thumb.

4.7 Advanced Metering Infrastructure

George et al. (2008) estimate the reliability benefits associated with AMI in Vermont. AMI can help locate outages, which leads to faster restoration and shorter interruption durations. This study estimates the benefits of shorter interruption duration by forecasting annual interruption costs with and without AMI for the lifetime of the investment. The reduction in interruption costs achieved by AMI is the reliability benefit to the customer in each year. After applying a discount rate to future benefits, the study is able to estimate the net present value to the customer in the form of increased reliability over the lifetime of the AMI investment.

For the baseline scenario without AMI, the study averages 2005 and 2006 CAIDI and SAIFI values for each utility in Vermont. It is assumed that CAIDI and SAIFI will remain constant at the 2005 and 2006 averages if the AMI investment is not made. Basically, reliability is forecasted to remain at the status quo without AMI. With AMI, this study employs an estimate of a 5% reduction in CAIDI relative to the baseline in each year. SAIFI is not expected to change because it is assumed that AMI does not impact interruption frequency.

In order to estimate aggregate interruption costs in the baseline and project scenarios, an econometric model is used. Table 4-6 shows the key inputs for the econometric model. The five large utilities in Vermont were analyzed along with a grouping of the smaller utilities. In the baseline scenario without AMI, CAIDI varies from 48.6 minutes at Burlington Electric to 153 minutes at Central Vermont. In the project scenario with AMI, CAIDI is projected to be 5% lower than the baseline in each year. SAIFI does not change in the baseline and project scenarios and varies from 1.24 at Burlington Electric to 4.4 at Washington Electric. Another key input into the econometric model is the average annual kWh for commercial and residential customers within each utility. Industrial customers of 200 kW or more were not included in the analysis.

Based on the average annual kWh and CAIDI baseline within each utility, the econometric model estimates cost per event for commercial and residential customers. This cost per event is multiplied by SAIFI to calculate the annual cost per customer. Finally, the annual cost per customer is multiplied by the number of customers to estimate the aggregate interruption costs for commercial and residential customers. The study follows the same process for the project scenario with AMI except with a 5% reduction in CAIDI. The annual reliability benefit for commercial and residential customers is the difference between aggregate interruption costs in the baseline and project scenarios.

Table 4-6:
Key Inputs for George et al. (2008)

Utility	SAIFI	CAIDI Baseline (minutes)	Commercial Customers		Residential Customers	
			Number of Customers	Avg. Annual kWh	Number of Customers	Avg. Annual kWh
Burlington Electric	1.24	48.6	3,643	53,093	16,197	5,628
Central Vermont	1.90	153.0	21,506	41,316	131,483	7,297
Green Mountain Power	1.70	99.0	14,004	50,421	78,367	7,430
Vermont Electric Coop	3.00	147.0	3,009	72,416	33,217	7,297
Washington Electric	4.40	108.0	255	13,151	9,917	6,231
Smaller Utilities	2.80	90.6	2,975	29,023	17,698	6,339

Table 4-7 summarizes the results of this study. The total reliability benefit is the sum of the two sectors. In total, the estimated annual reliability benefit to customers as a result of AMI deployment in Vermont is $1.758 million, most of which comes from the commercial sector. To determine whether this investment is cost-effective, the reliability benefit is combined with all of the other benefits of AMI and compared to the cost.

Table 4-7:
Results for George et al. (2008)

Utility	Annual Reliability Benefit Per Customer ($)		Annual Aggregate Reliability Benefit ($k)		
	Commercial	Residential	Commercial	Residential	Total
Burlington Electric	$7.36	$0.03	$26.8	$0.5	$27.3
Central Vermont	$47.04	$0.18	$1,011.6	$23.7	$1,035.3
Green Mountain Power	$24.11	$0.10	$337.6	$7.8	$345.5
Vermont Electric Coop	$70.59	$0.27	$212.4	$9.0	$221.4
Washington Electric	$69.71	$0.28	$17.8	$2.8	$20.6
Smaller Utilities	$35.49	$0.15	$105.6	$2.7	$108.2
		Total:	**$1,711.9**	**$46.4**	**$1,758.2**

This study demonstrates the cost per event approach that is recommended in Section 3. The estimated interruption cost per event is calculated with and without AMI and then this value is scaled up by SAIFI and the number of customers. Cost per event is calculated using an econometric model that customizes estimates to the area and customer class being studied. In addition, considering that interruption duration is a key input into the econometric model, the model estimates costs for varying CAIDI values. With such a model, planners do not need to round CAIDI to the nearest duration value for which an interruption cost estimate is available. Ideally, each utility would build an econometric model based on data from its own interruption cost survey. However, if this is not an option, the econometric model in Sullivan et al. (2009) can be used instead. Either option is an improvement upon relying on one or two point estimates because interruption costs vary significantly by geographic area, customer class and interruption duration.

A weakness of this study is that it relies on relatively simplistic forecasts of SAIFI and CAIDI with and without AMI. Without AMI in the baseline scenario, it is assumed that SAIFI and CAIDI remain at the status quo for 20 years. This scenario seems unrealistic because reliability varies over time. With AMI in the project scenario, the only difference is that there is a 5% reduction in CAIDI. This scenario seems simplistic because the expected reduction in CAIDI may take time to accrue as the technology is being implemented and the utility changes its processes for responding to outages. In addition, the reduction in CAIDI may not be as large towards the end of the lifetime of the AMI investment as the technology depreciates. Nonetheless, these forecasts may be the best available and because of the uncertainty, they employ a relatively conservative estimate of a 5% reduction in CAIDI.

5 SUMMARY OF RECOMMENDATIONS

1. Reliability benefits should be calculated based on well-established reliability statistics that are routinely collected by utilities under Part 411 of Title 83 of the Administrative Code of the Illinois Commerce Commission.

2. Calculations based on expected or observed changes in CAIDI and SAIFI should be required when parties are providing evidence of the impacts of Smart Grid investments on sustained interruptions.

3. 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.

4. As much information as is available should be provided in statistical analyses intended to quantify the impacts of Smart Grid investments on reliability.

5. The impacts of statistical variation in reliability indicators and evidence of historical trends in reliability indicators should be described in evaluating the observed or expected magnitude of reliability impacts of reliability investment alternatives.

6. Because timely and accurate statistical surveys of customer interruption costs have never been carried out in the region served by the ICC, it should require utilities in its jurisdiction to carry out careful surveys of the costs of electricity supply interruptions and power quality disturbances. This study could be carried out by individual utilities or jointly if they choose to do so.

7. The methods used in carrying out this survey should comport with generally accepted survey practices for estimating customer interruption costs set forth in: Sullivan, M.J., and D. Keane (1995). *Interruption Cost Estimation Guidebook*. Report no. TR-106082. Palo Alto, CA: EPRI.

8. In the interim, between the present and the time that outage cost surveys as described in 6 and 7 above are completed, interruption costs to be used in estimating the value of service reliability should be derived from the econometric equations set forth in: Sullivan, M.J., M. Mercurio, and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

9. Finally, the ICC should open a discussion with stakeholder utilities to determine how power quality disturbances are measured and whether these measurements are

accurate. Based on this discussion, a framework for estimating power quality benefits can be established.

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