# Evaluating Electric Reliability Projects Using Value of Service

*Many factors must be considered when selecting and prioritizing utility infrastructure projects, including public safety, obligation to serve, environmental impacts, system performance, and financial costs and benefits. For projects that improve service reliability, decision-makers should also consider the value customers place on avoiding unplanned service outages, also known as the Value of Service (VOS). This paper describes an approach to estimating the VOS benefits of electric transmission and distribution reliability projects at PG&E.*

## I. Introduction

One criterion in evaluating any investment is the level of benefits relative to the costs. However, many costs and benefits, including those related to public safety and health, the environment, and aesthetics are difficult to quantify and there is less confidence in their appraisal. As a result, economic evaluation of projects is typically limited to financial costs and benefits incurred by PG&E, while the decision to invest considers other factors, along with non-quantified or uncertain costs and benefits. For example, a decision to invest in infrastructure required to supply electricity to a new shopping mall is driven primarily by PG&E's obligation to serve, while a decision to invest in a project that improves utility service reliability at an existing shopping center may be driven by consideration of the potential costs suffered by the center's businesses and tenants in the event of a power outage.

In the last 25 years, a number of studies have been conducted that attempt to measure the interruption cost to utility customers that result from power outages.[1] While value-based reliability planning concepts have been in use for over two decades, the approach is limited by simplified assumptions and dependence on electricity customers self-estimating their loss (expressed in dollars) during power outages of various durations. As a result, the analytical results may under- or overestimate the cost of customer outages and, because of this uncertainty, PG&E does not include VOS-based estimates as a benefit in its basic discounted cash flow analysis of financial costs and benefits. Rather, VOS results are presented as additional information to inform decision makers of the potential magnitude of customer benefits associated with a project under consideration.

To illustrate the VOS concept, consider a situation where a substation component is expected to fail at some point in the next two years, resulting in an unplanned four hour outage. The failure can occur at any time during the two years, so on an expected basis in each year there is a 50% probability of an unplanned four hour outage.[2] A VOS survey indicates such an outage would result in a $20 million loss by the businesses and residents served by the substation. However, a proposed $10 million substation upgrade will result in the probability of an unplanned four hour outage declining to 1%

[1] Ernest Orlando Lawrence Berkeley National laboratory "Estimated Value of Service Reliability for Electric Utility Customers in the United States", June 2009

[2] Generally, there could be a probability of an outage in each year going out several years. The cost of the outage would be the probability weighted expected loss in each year discounted back to the present.

annually over the next 20 years. The value to customers of this upgrade is $19.6 million (the upgraded substation reduces the expected probability of a $20 million outage within two years from 100% to 2%, so the expected value of the benefit is 98% of $20 million). This customer benefit should be considered in addition to PG&E's financial costs and benefits when deciding whether to proceed with the project.

For many projects, unlike the simple example above, the value customers place on more reliable service may be less than the cost of the project. But before rejecting the project, other outage costs that aren't quantified, such as public health and safety, should be taken into consideration. Overall, judgment must be applied to both quantitative and qualitative costs and benefits, and attention must be given to the level of confidence in their valuation, before rendering a decision.

## II. Estimating Value of Service and the Customer Damage Function

The customer costs of an outage are known as the Customer Damage Function (CDF). These costs depend on the length of outage, the time of day, day of week, season of year, the number and types of customers, presence of backup equipment and business continuity plans, temperature and other environmental conditions. Expressed mathematically:

*Customer Loss = f (interruption attributes, customer characteristics, other factors)*

Customer damage functions are typically based on surveys, in which members of various customer classes (residential, small commercial, etc.) are asked to estimate the cost to them, net of any benefits, associated with outages of various durations and at different times of the day, week, and year. A number of studies have been conducted to estimate the CDF as a function of the various independent variables.

In 2012, PG&E commissioned a VOS study in response to a directive by the California Public Utilities Commission (CPUC) to estimate the costs customers incur during power outages and obtain other information regarding service reliability. This research, which was conducted by Freeman, Sullivan & Co., was designed to collect detailed outage cost information from residential, small & medium business (SMB), large business and agricultural customer classes and 1) estimate 2012 outage costs by customer class and region; 2) determine how costs vary by outage timing for each customer class; 3) compare 2012 outage cost estimates by customer class to those of previous studies; and 4) understand the level of reliability that is considered acceptable within each customer class. This 2012 study forms the basis for PG&E's development of the CDF.

Tables 1 and 2 below show the aggregated results of the survey data for the San Francisco Bay Area[3] and for the rest of PG&E's service territory, respectively. These values represent the average outage cost across all times of the day and week.

[3] The Bay Area includes the following 8 PG&E divisions: San Francisco, Peninsula, De Anza, San Jose, Mission, East Bay, Diablo and North Bay. The non-Bay Area region includes all other divisions.

Table 1. Bay Area Average Customer Interruption Costs, Per-Event (in 2012 $'s)[4]

| Duration \ Outage Type | Residential | Small/Med Business | Large Business | Agricultural |
|---|---|---|---|---|
| 5 Minutes | $8.18 | $585 | $430,784 | $124 |
| One Hour | $13.22 | $2,679 | $487,093 | $299 |
| Four Hour | $19.59 | $6,608 | $607,195 | $2,512 |
| Eight Hour | $26.63 | $16,464 | $610,909 | $4,867 |
| Twenty-Four Hour | $37.83 | $33,781 | $1,273,659 | $8,392 |

Table 2. Non-Bay Area Average Customer Interruption Costs, Per-Event (in 2012 $'s)

| Duration \ Outage Type | Residential | Small/Med Business | Large Business | Agricultural |
|---|---|---|---|---|
| 5 Minutes | $6.96 | $159 | $24,308 | $148 |
| One Hour | $10.71 | $974 | $54,970 | $462 |
| Four Hour | $14.89 | $2,761 | $113,746 | $1,202 |
| Eight Hour | $19.79 | $4,435 | $147,383 | $2,497 |
| Twenty-Four Hour | $26.03 | $8,515 | $615,402 | $5,764 |

Note in the tables above that residential customers tend to have the least amount of losses, whereas businesses, especially large businesses including industrials, tend to have the highest.[5] Also note the estimated losses are not linear, that is, losses due to an 8-hour outage are not 8 times losses due to a 1-hour outage. Because of the non-linearity of the CDF as a function of outage duration, it is best to estimate the CDF on a per event basis, e.g., separately evaluate the total cost of momentary events, one hour events, etc. For outage durations between the parameters surveyed, interpolation may be used to estimate outage costs by event.

Given the data available, the customer damage function is then given by:

Customer Loss = $\Sigma\, C_i * N_i$, where $C_i$ is the number of customers, and $N_i$ is the loss per event for that duration outage and customer class i.

A key attribute of any outage is when it occurs – a summer weekday (generally a time of the most economic activity and residential consumption), or a winter weekend (generally a time of less economic activity and less residential consumption). Data for outages in PG&E's territory generally show that unplanned outages occur at random times. Therefore, most reliability project analyses should use average VOS values covering all time periods. However, in system planning, the need for a capacity expansion project is often determined as a function of peak loads. For example, a substation may be operating at or near its peak capacity on weekday afternoons, so an overload and outage is most likely in that time period. Analysis of a project to increase the capacity of the substation should consider this expected timing in estimating outage related customer losses. Adjustments for expected outage timing, as a percentage of the average "base" values shown in Tables 1 and 2 above, can be found in the Appendix.

[4] Bay Area Large Business values have been reduced 43 percent from those published by Freeman and Sullivan to adjust for extremely high outage costs reported by customers who rarely experience outages.
[5] Tables included in the VOS study report summarize customer losses as a function of various parameters.

## III. Illustrative VOS Calculation Using Customer Interruption Costs

The Sodor Island Distribution Substation serves 40,000 customers in PG&E's Sierra Division. It is 57 years old and is showing signs of deterioration. Experience at this substation and similar substations indicates that each year there is: 1) a one in five chance of an equipment failure resulting in an unplanned one hour outage for all customers served by the station, 2) a one in ten chance of a more significant problem resulting in a four hour outage for 26,000 customers, and 3) a one in fifty chance of a major failure resulting in an eight hour outage for 5,000 customers.[6] A capital project has been proposed to alleviate these conditions by increasing the number of distribution transformers from two to three, upgrading the distribution bus with modern vacuum switchgear, and improving the physical layout of the transmission bus. The project is expected to have a service life of 30 years.

To estimate the expected annual customer interruption cost in the Status Quo case (where the proposed capital project is not adopted), the information above is used to develop the following table:

| **Outage Event Scenario Summary** | Event 1 | Event 2 | Event 3 |
|---|---|---|---|
| Outage Duration (hours) | 1 | 4 | 8 |
| Annual Probability of Occurance | 20% | 10% | 2% |
| Number of Customers Affected | | | |
| Residential | 35,212 | 23,474 | 4,401 |
| Small/Med Business | 3,954 | 2,636 | 494 |
| Large Business | 7 | 5 | 1 |
| Agricultural | 703 | 469 | 88 |

With the information in this table and the Non-Bay Area cost per event data in Table 2, the following calculation can be made to estimate the expected annual customer interruption cost:

| | Event Scenario 1 | | | Event Scenario 2 | | | Event Scenario 3 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Cust/Event | Cost/Cust 1 Hour | Cost/Event | Cust/Event | Cost/Cust 4 Hour | Cost/Event | Cust/Event | Cost/Cust 8 Hour | Cost/Event |
| Residential | 35,212 | 10.71 | 377,121 | 23,474 | 14.89 | 349,528 | 4,401 | 19.79 | 87,096 |
| Small/Med Business | 3,954 | 974 | 3,850,801 | 2,636 | 2,761 | 7,278,260 | 494 | 4,435 | 2,190,890 |
| Large Business | 7 | 54,970 | 384,790 | 5 | 113,746 | 568,730 | 1 | 147,383 | 147,383 |
| Agricultural | 703 | 462 | 324,505 | 469 | 1,202 | 563,504 | 88 | 2,497 | 219,701 |
| Annual Probability | | | 20% | | | 10% | | | 2% |
| Expected Annual Cost | | | $ 987,443 | | | $ 876,002 | | | $ 52,901 |

Total Expected Annual Customer Cost = $1,916,347

If the study period for the economic analysis is 30 years, then the VOS impact of the Status Quo alternative is the present value of $1,916,347 (after tax) over 30 years, discounted at 7.6 percent, or $13.3 million.

[6] Note that if an outage will happen only when two or more situations occur – for instance, one line feeding a station is down for maintenance and another line trips – then the probability of the outage should be a ***conditional*** probability reflecting the chance of the situations occurring at the same time, e.g.
P(outage) = P(line 2 trip when line 1 is down) x P(line 1 down).

# APPENDIX: VOS Adjustment for Outage Onset Timing

The 2012 VOS study provided useful information on how outage costs vary across different times of the day and week. Figure 1 provides the weekday relative cost per outage event estimates and Figure 2 provides the weekend estimates, which were derived from the customer damage functions. If a planning application requires an adjustment of outage costs that accounts for onset time, these relative values can be applied to each average outage cost estimate in Section II (referred to as the "base value"). As shown in the figure, outage costs for Small and Medium Business (SMB) customers are the most sensitive to onset time, varying from 82.5% lower than the base value on a weekend evening to 85.5% higher on a weekday morning. Considering that SMB outage costs vary substantially depending on the onset time, it is important that capacity planning applications apply these relative values.

**Figure 1: Relative Cost per Outage Event by Onset Time and Customer Class – Weekdays**

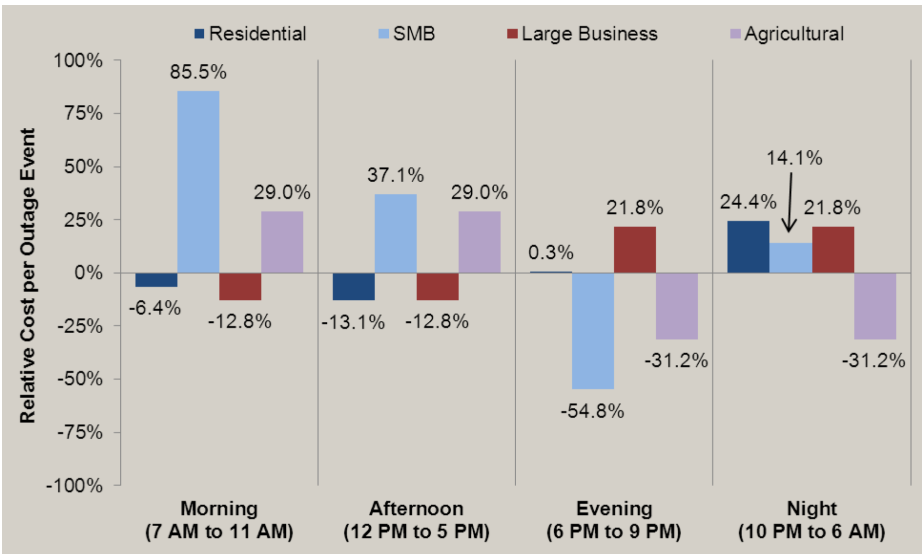


**Figure 2: Relative Cost per Outage Event by Onset Time and Customer Class – Weekends**