Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects

Revision 1, Measuring Impacts and Monetizing Benefits

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PRODUCT DESCRIPTION

This report presents a step-by-step process for estimating the costs and benefits associated with Smart Grid demonstration projects. In its entirety, the guidebook is meant to function as a standalone user's manual for the analysis process, from the initial step of describing the project to the final step of communicating the results to all stakeholders. This revision of the Guidebook updates and supersedes the material in the original Volume 1, published in 2011, but goes further by adding detailed discussion of monetization of benefits. The steps included in this volume present detailed instructions beginning with the overall design of the demonstration project, leading to execution of the research plan and analysis of data produced. The basic methodology is built on the framework described in the *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects,* published by EPRI in January of 2010.[1]

Results and Findings

As Smart Grid technologies evolve from the research and development environment to production testing and deployment, reliable methods will be needed to value the benefits of the new technology and weigh these benefits against the cost of deployment. Having a consistent, credible, and transparent approach will help promote the deployment of Smart Grid investments where they will yield the greatest value for customers, utilities, and society.

Challenges and Objectives

Integrating smart technology into the electricity distribution system is complex. There are many new devices and systems that can be deployed in a variety of different applications. Multiple technologies can be part of a single project. Not enough is known about their performance to determine which technologies (or portfolio of technologies) will be optimal across the spectrum of possible applications. Thorough documentation of actual field performance will help resolve questions about how individual technologies and portfolios of technologies are likely to perform under different operating conditions and levels of investment. The valuation process is also complex because many Smart Grid investments produce indirect impacts. Their benefits are derived from how they enable us ". . . to integrate, interface with, and intelligently control innovations such as wind turbines, plug-in hybrid vehicles, and solar arrays."[2] Thus, a large part of the value of some Smart Grid investments is derived from other technologies whose use they enable. Assessing the value of Smart Grid investment must address the functions it enables, as well as the value that it provides directly.

Applications, Values, and Use

Engineers, planners, project managers, and other professionals can perform cost/benefit analysis for Smart Grid demonstrations by following the steps listed in the complete guidebook. Any project stakeholder involved in the process of defining specific values related to Smart Grid technology implementation will find value in its methodology. The process will allow for

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[1] EPRI, Palo Alto, CA: 2010. 1020342.

[2] Litos Strategic Communication, "The Smart Grid: An Introduction," prepared for the U.S. Department of Energy, Contract No. DE-AC26-041818, Subtask 560.01.04, undated, p. 15.

accurate analysis of the costs and benefits of various Smart Grid designs and will ultimately aid the stakeholder in steering Smart Grid deployment to provide the greatest value to beneficiaries.

The goal of the guidebook is to present a comprehensive set of guidelines and specific instructions for estimating the benefits and costs of Smart Grid projects. It is unique in its level of technical specificity and in the range of technologies it is intended to cover. It is intended to complement previous publications that deal with the concepts of cost/benefit analysis as applied to Smart Grid. Finally, it is intended to help utilities produce evaluations that meet reporting requirements for DOE-funded Smart Grid projects, as well as provide the types of information that regulatory commissions are likely to require in order to approve the investments for cost recovery through regulated rates.

The Approach

The guidebook presents a step-by-step framework that provides a standardized approach for estimating the benefits and costs of Smart Grid demonstration projects. This guidebook contains detailed discussion of the first twenty-one steps, from initial project definition to monetization of benefits. Further, it applies these steps to a specific Smart Grid technology to illustrate how the methodology can be applied.

Keywords

Smart Grid
Smart Grid benefits
Smart Grid costs
Functionality
Demonstration projects
Cost/benefit analysis

ABSTRACT

This report presents a step-by-step process for estimating the costs and benefits associated with smart grid demonstration projects. The entire guidebook is meant to function as a standalone user's manual for the analysis process, from the initial step of describing the project to the final step of communicating the results to all stakeholders. This version of the guidebook presents detailed instructions for describing the project objectives, research plan, and technologies deployed; associating the technologies with enabled functions; and mapping these functions to impacts. The report discusses the translation of impacts to cost and benefit categories for a cost/benefit analysis. The report builds on the Electric Power Research Institute (EPRI) report *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects* (1020342).

EXECUTIVE SUMMARY

Smart Grid initiatives are taking place all over the world using advanced technologies to optimize the performance of the power system to benefit consumers and society at large, as well as utilities. Understanding the costs and benefits of Smart Grid applications requires an in-depth assessment of the technical and economic performance of the applications as well as the interoperable communications networks that support them. To support such assessments, a report jointly funded by the Department of Energy and EPRI entitled, "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects (EPRI 1020342)," provides a framework for estimating benefits and costs associated with Smart Grid projects. Building on that publication ("Methodological Approach"), this guidebook functions as a standalone manual that guides the user step by step through experimental design to support a valid, supportable cost/benefit analysis (CBA).

Performing cost/benefit analysis on Smart Grid systems poses interesting and challenging problems in measuring physical impacts and estimating economic benefits from them. However, when the Smart Grid systems are part of first-of-kind or demonstration projects, there are additional challenges to producing meaningful cost/benefit analysis. Because of the numerous learning curves involved and the limited circumstances encountered, demonstration projects alone cannot provide information sufficient to support major decisions on full-scale implementation of smart grid applications on large diverse power systems. In particular, the costs to establish demonstration projects are likely higher per installation than could be achieved on wider implementation with economies of scale and known technologies. However, demonstration projects do provide opportunities for gaining necessary experience, promote progress along the various learning curves, and establish a base of impact data that can inform cost/benefit analysis for smart grid installations of broader scale and scope. Supporting that objective, this Guidebook concentrates on processes to establish scientifically based measurement techniques and protocols for measuring objective impact data. In addition, techniques for converting physical impacts into monetary benefits will be discussed in some detail, though in some areas analysts must choose among an array of techniques of varying cost and precision. Impacts measured in well-designed experiments may be extensible to analyses of broader scope even though the implementation costs of the demonstration may not be representative of routine manufacture and installation. Techniques for extending the use of demonstration data into projects of greater scope and scale will not be a part of this volume, but may be addressed in subsequent revisions.

Acknowledging these limitations, the Guidebook adopts the dual purposes of 1) creating/describing a proper experimental framework for measuring impacts in demonstration projects, and 2) laying out a CBA process with techniques that may ultimately be used in a decision-making framework for broader application. This is accomplished through a twenty-four-step procedure that establishes an experimental demonstration framework for impact measurement followed by methodologies for monetizing impacts to support the benefit side of a cost/benefit analysis. Adhering to the steps will also produce informative documentation of the demonstration project and its experimental design, substantiating the measurements taken.

To begin the CBA process, Section 3 of the Guidebook guides the user in starting the basic project documentation, describing the project purpose and the initial situation analysis: the problem or opportunity to be addressed by the smart grid application. Ideally this describes the baseline scenario, the conditions against which impacts will be measured. The user establishes project objectives intended to solve the problem or take advantage of the opportunity. The section also outlines background information to be included in the project summary, such as the geographic scope of the project, technologies involved, targeted customer groups, project partners, a high-level project timeline, etc. The summary also casts the project in its organizational, market, and institutional contexts, and their importance to the project is examined. Finally, the section answers at a high level some basic questions about the project, i.e., what the application is expected to do and what is expected to be accomplished. This sets the stage for determining answers to these questions through the structured process.

In Section 4, several lists are produced, the first being the devices, systems, and other mechanisms that are to be deployed in the project. Based on this information, the user creates a list of functions that will be provided or enabled by the deployment. This stage is intended to be equipment-focused, inclusive, and exhaustive, so that all possible functions are considered, leaving nothing out. The next step may narrow this list down to a set of functions that will be employed in the specific application under study, while others may be left unused or precluded by mutual exclusivity.

Section 5 guides the user through creating a comprehensive research plan. This begins with defining the research problem, i.e., the task of designing experiments to produce meaningful measurements that substantiate the performance of the smart grid application. This section also guides the development of a set of hypotheses that focus on measurable quantities that will reveal the expected project impacts, specifying the experimental design and establishing the baseline for each measurement. The plan further includes a detailed project timeline specifying the timing and duration of various experiments. In addition, the user develops measurement and verification protocols for the experiments, including data collection instructions and identification of data collection points, as well as data testing, screening, storage and retrieval protocols.

Section 6 discusses the structure of a cost/benefit analysis, discussing how to extrapolate experimentally derived impacts into long-term impact estimates useful for monetization. It discusses estimation of project's impact from measured quantities, examining some of the challenges that face experimenters in a number of specific areas. Methods for estimating and monetizing benefits based on project impact metrics are discussed. Naturally, monetization rests on various inputs unique to the utility, market, or region, and the most appropriate monetization method in any case may vary by situation. Each benefit should tie to some physical impact measurement, but there may be a different monetization method for each benefit. This section provides, where possible, a menu of approaches that may vary in accuracy and cost to employ.

Section 7 discusses the remaining steps that are to be fleshed out in detail in future revisions to the Guidebook.

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1
BACKGROUND

Purpose and Overview

This guidebook presents a step-by-step framework for conducting a cost/benefit analysis, from the preliminary stage of identifying the problem or opportunity that the project addresses, to the communication of the analytical results to stakeholders. It supersedes and extends the "Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects: Volume 1: Measuring Impacts." In this volume, the first twenty-one steps are discussed in some detail. This document builds on a previously published report, the *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*, ("Methodological Approach") which was co-funded by the Electric Power Research Institute (EPRI) and the U.S. Department of Energy (DOE).[3] That report provides broad context for this guidebook in that it:

- Presents a general methodological approach for estimating benefits and costs of Smart Grid projects,
- Describes a broad range of issues associated with measuring technology impacts as a precursor to assigning monetary values,
- Summarizes recent studies assessing the benefits and costs of Smart Grid technologies, and
- Provides references and data sources that can be used for estimating a variety of inputs and assumptions.

Though this guidebook builds on the previous work, it is intended to be a standalone practical guide for designing experiments and demonstration projects that produce consistent and transparent results that can be understood and validated by a range of interested parties. Although the guidebook steps can be implemented without side-by-side reference to the Methodological Approach, the latter contains useful background which is referenced herein.

The guidebook is intended to facilitate consistent and insightful implementation of Smart Grid pilot programs and experiments. Verifiable experimental results will facilitate extraction of research value from the demonstration projects, and promote deployment of the technologies in a manner that maximizes the benefits to customers, utilities and society. Further, EPRI's goal is that the EPRI-sponsored Smart Grid projects yield experimental results that will advance our understanding of where, how, and under what conditions (grid characteristics, market structures, climate, system operating conditions, etc.) the various systems can be expected to perform. To that end, the guidebook provides a format that utilities can use to articulate how a specific technology is expected to perform and to demonstrate those impacts convincingly. It also guides the preparation of detailed documentation of projects and experiments so that results can be evaluated and validated by others.

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[3] EPRI, Palo Alto, CA: 2010. 1020342.

This revision of the *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects* follows the workflow presented in Figure 1-1 below.

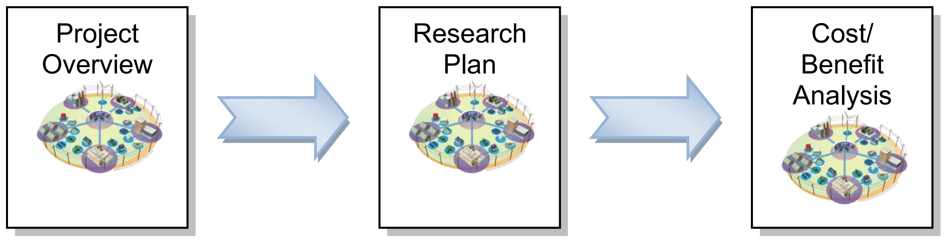

Figure 1-1
Workflow of Guidebook CBA Process

Viewed broadly, the guidebook guides a process to:

- Develop initial project documentation
- Identify and measure project impacts
- Associate impacts with project benefits
- Develop a detailed research plan
- Track project costs that are aligned with the specific project deployment and operation, and
- Develop final documentation of costs, impacts, and benefits

This process will promote consistency across the industry in how costs and benefits attributable to Smart Grid demonstration projects are estimated. This consistency will facilitate comparisons across projects undertaken in different locations over time, thereby leveraging the learnings from the pilots and demonstration projections.

Appendix A is a list of acronyms, abbreviations, and definitions of selected items from the document. Appendix B is a list of Smart Grid Functions as discussed in the report. Appendix C is an example of the guidebook's workflow process applied to a generic Volt/VAR optimization project. Appendix D is structured in workbook format to allow users to document project information and data as they work through the cost/benefit analysis process outlined in this report.

What Is a Smart Grid?

The National Energy Technology Laboratory (NETL) has developed a list of seven principal characteristics of a Smart Grid that have been widely adopted across the industry. They are described in detail in Section 4 of the DOE/EPRI Methodological Approach and are summarized here.

The principal characteristics are that a Smart Grid[4]:

1. Enables informed participation by customers
2. Accommodates all generation and storage options
3. Enables new and improved products, services and markets
4. Provides power quality for the range of needs in the 21st century economy
5. Optimizes asset utilization and operating efficiency
6. Addresses disturbances through automated prevention, containment and restoration
7. Operates resiliently against all hazards

Distilled to basics, a Smart Grid exploits new technologies and communications to enhance overall power system operations and customer-side efficiency. Some applications improve reliability of service for customers, some lower the utility's cost of providing service, while others provide customers with new information and choices. DOE lists five fundamental technologies that will drive the Smart Grid: [5]

- Integrated two-way communications connecting components, using open architecture to enable real-time monitoring and control
- Sensing and measurement technologies such as remote monitoring to support faster and more accurate response to system conditions
- Advanced components, applying the latest research in superconductivity, storage, power electronics and diagnostics
- Advanced control methods, and intelligent devices that can accept data and implement optimization and improved control of the system
- Improved interfaces and decision support for utility operating personnel

What is a Smart Grid Demonstration Project?

The Methodological Approach was written to describe a process for cost/benefit analysis specifically for Smart Grid demonstration projects, which are implicitly defined as installations of Smart Grid equipment for which impacts would be measured. This guidebook continues with that assumption, describing how to set up experiments for operating equipment in various ways. However, once Smart Grid equipment is deployed, there may be projects oriented toward exploring new applications of the capabilities, including applications that engage customers in a variety of ways. In general, the CBA techniques described in the Methodological Approach and in this Guidebook are applicable to all manner of utility activities including customer engagement, but the measurement and experiment techniques described in the Guidebook are

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[4] Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects, EPRI, Palo Alto, CA, 2010. 1020342, pp. 4-5 thru 4-11.

[5] Litos Strategic Communication, *The Smart Grid: An Introduction*, prepared for the U.S. Department of Energy, Washington, DC, Contract No. DE-AC26-04NT41817, Subtask 560.01.04, p. 29 (undated).

explicitly oriented toward equipment-based projects that do not involve customer interaction and decision-making.

It is important to realize that if the intended end result of the demonstration project is a cost/benefit analysis, then experiments must be designed specifically to generate data useful for the CBA, not just for testing and exploring the various possible uses of the equipment and showing that it works. This guidebook suggests planning time for both activities, with the proviso that sufficient time must be allotted to obtain enough information to be able to estimate impacts for full years of operation for the CBA.

How is Cost/Benefit Analysis for Smart Grid Projects Different?

While neither entirely new nor unique, the need for public enumeration of the economic benefits of utility investments is often not necessary, especially in the electric distribution area. Utilities regularly invest large sums in utility equipment devoted to public service in pursuit of their regulatory or charter obligations to serve. The benefits of extending service into newly developed areas, for instance, and planning for continued growth are generally accepted and implicit in the regulatory imperative/obligation. Utilities routinely fulfill these non-discretionary obligations while minimizing the cost of doing so, and utilities are usually well prepared to defend their decisions in this cost-minimization framework. Smart Grid projects, on the other hand, may not fit into this time-tested paradigm of cost minimization because they may be discretionary. For instance, if a smart grid project can improve reliability beyond currently acceptable levels, is it imperative to invest the money to do so? The proper answer is that it depends on how much must be invested to obtain the improvement, and whether the improvement gained is worth the money.

An enhanced form of utility planning, known as value-based planning, broadens the circle of cost minimization to include customer costs of interruptions where decisions may improve or otherwise alter the level of service reliability that customers experience. Value-based planning has long been common in economic justification of capacity reserve levels, but it can also be used at the transmission and distribution levels when addressing reliability improvements that may not have been required by reliability criteria. Demand-side activities that affect consumption patterns, either through pricing or hardware, bring further needs for careful analysis of costs and benefits, distinguishing even among groups of customers, such as participants and non-participants in a candidate program. Tests evaluating such decisions from a variety of perspectives were developed and published in California in the 1980s.[6]

Many Smart Grid investments are in this new category that requires going beyond utility-cost minimization. Besides their novelty, Smart Grid applications offer new benefits beyond basic service or lower cost. They may improve service reliability and quality beyond currently accepted levels. They may provide customers with choices they have never had before. Consequently they are discretionary for the utility, and a positive case is needed to bring such innovations into the regulated business. Eventually we may find that Smart Grid technologies are the only realistic alternatives for addressing technical issues that may arise when distributed energy resources and new services such as electric vehicle charging become common on

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[6] California, State of (2001) *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*, October 2001.

distribution systems. Nevertheless, such technical issues are mostly in the future, so today there remains the responsibility to make a positive economic and business case, showing benefits sufficient to offset costs.

Challenges in Cost/Benefit Analysis for Smart Grid Projects

Several attributes of Smart Grid investments make conducting cost/benefit analysis more challenging than for traditional utility investments.

Technology Diversity. The scope of the technologies involved can be quite broad and can range from the generation bus to the devices that customers use in their homes or businesses, and all of the communications devices in between. Many of the technologies are flexible systems that open a broad array of possible techniques and uses that have yet to be imagined. They can facilitate the integration of new technologies into dispatch operations and into wholesale electricity markets. They can facilitate the integration of distributed electricity generation installed at various locations on the system. In other words, the Smart Grid includes a varied lot of devices and technologies that can be used in a variety of ways, and their breadth requires involvement of people from many disciplines.

Scale of technologies. The scale of technologies can range from small, isolated parts of the grid to expansive projects that span several stages of the delivery system.

Scope of markets and market participants. Smart Grid investments can have impacts across customer classes, utility markets, market participants (including customers, utilities, and energy service companies), states, and regional market operators and reliability organizations such as Independent System Operators/Regional Transmission Operators (ISO/RTOs).

This combination of diversity, scale and scope span makes it challenging to generalize about market barriers and program beneficiaries, and complicates program evaluation. For example, if a distribution utility installs advanced metering infrastructure (AMI), the better data improves utility commercial operations. It may also improve performance of the distribution system, influence system-level supply costs, and even have regional implications. Sorting these out and making the proper attribution is challenging.

How should this Guidebook be used?

The guidebook was created to provide a practical instruction book performing cost/benefit analysis for Smart Grid *demonstration* projects, in which impacts are measured in deliberate experiments. That is, it assumes that the technology application in situ at reasonable scale is untested and perhaps unfamiliar, and that impacts are not known or certain ahead of time. Perhaps more importantly, it assumes that regulators, policy makers and perhaps even utility management do not have sufficient documentation or experience with these technologies to be able to conclude that they are worth the investment. Therefore, the process is intended not only to guide utilities through the process of the cost/benefit numerical exercise, but also to generate documentation in somewhat standard form that can be used to help inform management, regulators, policy makers, and the public at large about the impacts and value of Smart Grid investments.

The guidebook will also address the general shortcomings of cost/benefit analysis based on demonstration research. Demonstration projects bring new technologies into contact with utilities and customers for the first time, most likely at higher cost, with more technical glitches, and with lower performance than can be achieved in the future. In the process of demonstration and experimentation, both vendors and utilities will descend learning curves, ultimately producing better devices at lower cost, and designing better applications for them in the field. The demonstration CBA must deal with the reality of experimental results, while also looking forward in a deliberate, documented process.

Certainly, as the industry moves beyond the demonstration phase, when impacts have been understood, characterized and communicated, the deliberate documentation and experimentation phases will not be necessary, but cost/benefit analysis is likely to be needed. What is economical for one circuit may not be economical for all circuits, and among the extended aims of the demonstration initiative is to characterize the variables that will shape the economic choices in various situations in the future. However, in this demonstration phase, the CBA process is focused on measuring, verifying, and documenting impacts in Smart Grid demonstrations.

Twenty-four steps constitute the structure of the CBA process for a Smart Grid demonstration project. Multiple applications may coexist within a single project, and they may share space in a single documentation volume, but independent projects with independent non-interacting impacts and benefits should be treated with parallel tracks in the experiment phase through the ultimate economic comparison.

The steps are grouped into four sections, but they can be considered to be associated with three separate phases.

- The Project Overview

  This phase of the project prepares overview documentation that might be useful for communicating about the project in its early phases, perhaps before seeking approval. The document is intended as an externally facing document, in that it describes the utility, its regulatory context, etc. Beyond the initial project phases, this documentation will be useful as front matter for a case study fully describing the project to interested parties outside of the utility's immediate vicinity.

- The Research Plan

  This phase of the project includes all of the planning for the experimentation and measurement phase of the project, as well as for the cost/benefit analysis. Beginning with the description of the technology to be deployed and the benefits it will bring, it details the experiments to be run and the physical quantities that are to be measured during the experiments. The quantities are those needed to establish the extent to which the applied systems create physical impacts, subsequently to determine the economic benefits and the associated costs. This phase is internally facing, describing what people within the utility to do over the course of the demonstration project.

- The Cost/Benefit Analysis

  This project phase analyzes the data collected in tests and experiments, ultimately producing a cost/benefit analysis. This volume extends only through Step 21, stopping short of dealing with the scaling and scope issues encountered when analyzing demonstration or pilot projects.

The steps of the process are listed below, and grouped and associated with these phases of the process.

PROJECT OVERVIEW DOCUMENTATION

Step 1: Provide basic project identification information
Step 2: Describe the project and its major objectives
Step 3: Provide relevant Background information
Step 4: Provide a high-level budget and project timeline

TECHNOLOGY DESCRIPTION.

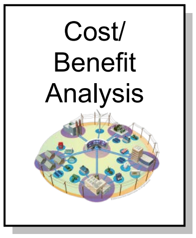
Step 5: Describe the technologies, devices, and systems to be deployed
Step 6: Describe the functions enabled
Step 7: Describe how the technology will be applied
Step 8: Describe the expected benefits
Step 9: Describe the expected impacts and performance metrics

DEVELOPING A RESEARCH PLAN

Step 10: Define the research problem
Step 11: Identify the physical measurements
Step 12: Describe relevant external factors
Step 13: Define the baseline quantities or methods of estimation
Step 14: Construct formal hypotheses to be tested
Step 15: Specify the experiments and how conducted
Step 16: Develop a detailed project timeline
Step 17: Provide data collection instructions, including collection points and periods
Step 18: Specify data testing, screening, storage and retrieval protocols
Step 19: Specify algorithms for calculation of impacts

ESTIMATING PROJECT IMPACTS, COSTS, AND BENEFITS

Step 20: Estimate physical impacts from measurements
Step 21: Monetize estimates of physical impacts
Step 22: Estimate costs incurred by customers per year for baseline and project
Step 23: Estimate utility costs by function/classification for baseline and project
Step 24: Summarize Costs and benefits



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OVERVIEW OF THE CBA PROCESS

A basic definition of Cost/Benefit Analysis (CBA) is analysis that seeks to determine whether the benefits of a project or decision outweigh its costs. However, CBA analyzes costs and benefits from a particular point of view, which may range from broad and societal (public perspective) to narrow and focused (private perspective). General economic analyses take a societal perspective, determining whether a project is a good allocation of societal resources, without regard to the distribution of benefits. This contrasts with financial analysis such as performed within investor-owned competitive firms, which is generally focused on returns to investors. In the middle ground is a form of analysis common in planning for regulated utilities in which the focus is on utility costs borne by customers. Regulated-utility planning analysis minimizes cost of reliable electric service while assuming return of investment and an opportunity for return on investment. Where utility-cost minimization does not comport with public policy goals, legislators and regulators may impose conditions intended to address those goals, in hopes of encouraging decisions that benefit society as a whole.

The Methodological Approach and this Guidebook put forth a CBA methodology that is compatible with societal or customer-oriented approaches to weighing costs and benefits. This concept fits most comfortably with fully integrated utilities, in that costs and benefits align easily and all are contained within one corporate envelope (except for externalities that fall outside of the electric sector). Costs in one part of a utility may be offset by savings in another part of the utility, minimizing or even eliminating needs for additional cost recovery. However, we recognize that users of this methodology represent a variety of utility entity types, many of which participate in only one or two of the utility functions of generation, operation, transmission and distribution. Costs incurred within one entity may produce offsetting savings in a separate corporate entity. Though consumers may be indifferent to where costs and savings occur, the various corporate entities involved face varying levels of cost-recovery risk depending on their regulatory situations and their position in the chain of costs and savings. This is important from a private perspective.

While this methodology is intended to be all-inclusive and customer/society-oriented in its point of view, utilities of all types should find the information useful for working with regulators and the public to obtain support for cost recovery so that such projects can go forward. If necessary, the information also may be broken into components that the user can apply to the situation of the individual entity. Projects with benefits outweighing their costs in a broad sense should be able to go forward, but in many cases utilities, regulators, and policymakers must make specific arrangements to provide for recovery of investment.

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PROJECT OVERVIEW DOCUMENTATION

The first several steps of the process are documentation steps, providing the user with a format that will produce a useful, standard report. This portion of the process can be done pre-project, which may be useful in the initial approval process for a demonstration project. Ultimately, projects documented in this standard format can be compared side-by-side with projects documented by many utilities in similar demonstrations, providing easily accessible information for utilities, regulators, policy makers, and the public.

The first process/documentation step is to provide a high-level overview of the project, describing generally what the utility proposes to do, the goals of the project, project participants (including any co-funders), the role of the regulator (if applicable), targeted customer groups, etc. At this juncture, the description need not be highly precise or technical; a detailed description of the project will be developed in subsequent steps, which describe the research problem, the technologies to be deployed, and a specific research plan.

General Project Information

Step 1 Provide basic project identification information.

General information would typically include the following types of information:

Name of Project	Official Smart Grid Demonstration Project Title
Project Description	Type of project in terms of equipment to be deployed and the project area, if applicable.
Lead Organization	Company Name
Other Participants	Smart Grid Demonstration Collaborators
Project Manager/ Contact Information	PM Name and Contact Information
Planned Duration of Project	Commencement and End of the Demonstration
Total Budget	Total Funding of the Demonstration
Government Cost Share	Portion of the Demonstration funded by government sources

Project Purpose

Step 2 Provide a general description of the project purpose

- **Problem/Opportunity Statement**
  Provide a concise but general description of the problem the utility is trying to solve or the opportunities for improvement that have been identified. For example:

  - Several long feeders in the [name] area have high losses and poor voltage control. [Utility] will address these issues in this area with centralized volt/var control.
  - The [name] area of the system experiences above-normal frequency/duration of customer interruptions owing to overhead lines in wooded subdivisions.
  - Integration of intermittent distributed generation is imminent in the service territory, indicating a need for additional visibility, volt/var controls, and switching capabilities on the distribution system.
  - Advanced meters installed over the past several years offer the opportunity to allow customers greater control of their energy costs through time/price-sensitive pricing.

  It is important to indicate whether the problem/opportunity deals with a specific area or whether it is a general issue. For instance, specific parts of a system may be singled out for reliability problems or high losses. Alternatively, some utilities may want to address reliability issues generally. This first statement of the problem/opportunity can be a concise capsule that doesn't elaborate on the problem details, as those are coming up next. A general reader should be able to quickly get the idea of what the project is intended to address, as well as what general technologies will be employed.

- **Brief Project Description**

  Describe the basic project elements, i.e., the technologies, devices and systems which will collectively comprise the Smart Grid project. This is not a thorough project description, but should provide enough information to give the reader an idea of the type of project, and providing the general location of the project to transition to the next section, which describes the current conditions there.

- **Current Situation/Business-as-Usual Description:**

  This section describes the current situation in the project area, including the problem areas that will be addressed by the project. This will describe the conditions that would prevail if the project were not undertaken. This situation will form the basis of economic comparison for the project performance. That is, as a baseline scenario it will provide the "but for" case, i.e., what would happen "but for" the project. While this calls for a description of the current situation, it can also look to future expectations, as some problems may be merely on the horizon rather than in current reality. Numbers can be provided here if relevant and clear, but this section is still front matter.

A situation analysis might describe:

- The cost of manual meter reading
- Reliability issues/indices in certain areas, and how they are affected by growth expectations
- Chronic high loss levels in certain areas
- Expected distributed generation additions and various means to accommodate them

Even at this early stage, it is a good idea to be expressing the descriptive items in terms of measurable quantities that will be affected by the project, working toward describing the project impacts.

- **Project Objectives:**

Describe project objectives, i.e., describe the main changes that the project is expected to allow or provide, preferably in terms of quantities measurable within the project area. Descriptive words such as "reduce" and "improve" describe changes relative to the current/baseline situation described above, and should be stated as closely as possible in the physical terms used to describe the problem or the current situation. Some projects may have complex impacts, perhaps affecting the way people within the utility do their jobs, but the goals need not go into a lot of detail at this point. There may be multiple impacts, but it is likely that one area dominates. This section should capture the main area of improvements, at a high enough level to avoid minute details. Some major areas that may be targeted are:

- Reliability (frequency and duration of customer interruptions)
- Utility Operational Efficiency (people and how they do their jobs: non-fuel O&M, non-production assets, public and employee safety)
- System Operational Efficiency (the power system and how efficiently it runs: losses, combustion, dispatch optimization, emissions)
- Utility Asset Efficiency (production assets required: GT&D)
- Power Quality (harmonics, sags/swells, voltage violations)
- Customer Efficiency (consumption required to provide desired benefits)

To the extent possible, stay within the project area and describe physical impacts. The ultimate benefit of a project may be reduced cost or even reduced emissions, and there is no harm in saying so here, but this statement should include information about the physical measures within the project area that will link with those ultimate benefits. There is no need to jump ahead to the cost/benefit analysis with a goal to lower overall cost. The objective of the CBA will be to determine whether the benefits of the project's impacts outweigh the likely costs in implementation, but the objective of the demonstration project should be to induce and measure physical impacts through the application of Smart Grid technologies.

For Example:

- The project seeks to improve operational efficiency of the distribution feeder, reducing energy losses by optimizing controllable var supply along the feeders, and by reducing customer energy use through conservation voltage reduction (CVR) strategies.

- The project seeks to induce demand response through time-varying rates, enabled by smart meters.

The project objectives, expressed in terms of quantities measurable within the project and relative to the "but for" scenario, will suggest experiments designed to determine project impacts in terms of these quantities.

Summary Project Description

Step 3 Provide a high-level background discussion and project summary

There are a number of different kinds of utilities operating in a variety of regulatory and market contexts. The regulatory and market situations can be very important to how Smart Grid projects are received. In particular, the regulatory situation is important to how cost is recovered, and the utility structure often cuts through where costs and benefits appear. In addition, some Smart Grid devices can be applied to sell products into a wholesale market system, whereas the same device within an integrated utility may provide a menu of services to its own operators. While these constraints and/or opportunities may be second nature to people internal to these utility situations, they will be very informative and explanatory to others who may not be as familiar with your utility or with utilities in general.

- **Background Section: Describe the utility and its regulatory/market contexts.**
  - **Description of utility, including**
    - Utility ownership type and structure
(Vertically integrated IOU, Co-op Distributor, Municipal T&D, etc.)
    - Service territory (preferably with map)
  - **Market structure context, including**
    - Wholesale energy market (Bilateral, Organized RTO/ISO, TSO/DSO):
Under what type of structure is wholesale energy bought and sold?
    - Retail energy market structure:
Is the utility a monopoly supplier to customers?
Are there distributors providing delivery-only service?
Are there energy-service providers?
Who handles retail meter data? Who owns it?
    - Transmission (integrated, monopoly, independent)
  - **Regulatory structure and Commissions**
    - Wholesale regulation (federal and/or state)
    - Retail regulation (state commission, town/city council, member/owner board)
    - Other relevant regulation (standards, land use, permitting, zoning, etc.)
    - Dominant type of pricing (de-coupled, conventional, dynamic, etc.)

- **Additional Project Description**
    - **Geographic Scope:** Describe the geographic scope and context of the project, preferably with maps showing their position within the service territory and other relevant geographic and demographic context information.
    - **Basic Project Elements:** Describe the basic project elements, i.e., the technologies, devices and systems which will collectively comprise a Smart Grid project. At this point in the documentation, a detailed equipment list is not necessary.
    - **Enabled Functions:** Describe the functions that the project will enable, distinguishing those that are possible from those that will be activated in the application that will be demonstrated and measured.
    - **Expected Impacts:** Describe the project's expected impacts, i.e., the physical changes the project will bring about in the project area, with emphasis on the metrics that will ultimately describe this performance. Though physical changes, such as reduced generation, can occur outside the project area, we concentrate here as close to the project area as possible, at the beginning of the causal chain that may lead to changes distant from the project. Extended impacts beyond the project area and economic benefits will be calculated from these impacts observed within the project area.
    - **Expected Benefits:** Describe the benefits expected to result from the project's impacts, i.e., the physical and monetary changes that affect people: customers, society, and/or the utility. Economic benefits are likely found beyond the project boundary, though related causally to impacts occurring within the boundary. For instance, reduced losses (an impact) lead to lower fuel cost and emissions outside of the project area.
    - **Targeted Groups or Area:** Describe the customer groups targeted or affected by the project, if relevant. This may be in terms of customer class – residential, commercial, and industrial – or in terms of geographical area.

Project Organizational Information

Step 4 Provide high-level project organizational information

- **Roles and Responsibilities**
    - **Co-Funders**
    - **Project Partners & Collaborators:**
      Description of roles and responsibilities of the various companies and organizations involved in the project, including functional organizational units internal to the utility. Roles and responsibilities can be organized based on various functional areas, as appropriate.
    - **Project Budget:** Summary of budget and sharing of cost among funders.

- **High-level Budget and Project Timeline**

  A high-level project budget and timeline may include the activities listed below:

  - Project development (including internal & external approvals of budget & scope)
  - Regulatory approvals (if required)
  - Pre-planning and preparation (equipment purchases & installation, development of marketing, communication and customer recruitment materials, if relevant)
  - Time required to measure baseline conditions
  - Field implementation, data collection and monitoring
  - Time required for data collection, processing, analysis and report writing

Table 3-1
High-Level Project Budget and Timeline

High-level Project Budget and Timeline		Date		2013				2014				2015				2016			
Task	Budget	Begin	Complete	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Project Development																			
Project Summary Development																			
Identify roles & responsibilities																			
Outline project goals and objectives																			
Develop project budget																			
Identify project partners and collaborators																			
Internal Approvals (Budget & Scope)																			
External Approvals (Budget & Scope)																			
Regulatory Approvals																			
Local, State, Federal Approvals																			
Regulatory Commission Approval																			
Pre-Planning & Preparation																			
Equipment Purchases																			
Equipment Installation																			
Marketing Material Development																			
Communication & Customer Recruitment																			
Baseline Measurements																			
Identify quantities and durations for baseline measurement																			
Measure baseline quantities																			
Field Implementation																			
Technology installation (by project phase or sub-project)																			
Data Collection																			
Data collection (start - end)																			
Data processing (start - end)																			
Data analysis (start - end)																			
Reporting																			
Internal reporting (start - end) per requirement																			
DOE reporting (if applicable)																			
Other reporting requirements																			

The Product of Steps 1-4: A document describing the project at a summary level

The steps in this section provides the high-level information necessary to introduce the Smart Grid demonstration project, provide the background justification for development of the project, and communicate the overall project goals and objectives. The subsequent sections will provide greater detail on the various stages of the process.

The document produced in this section can be created and used internally or with regulators as a part of the project proposal. However, because it provides background information such as the regulatory and market context, it can be useful externally, with parties less familiar with the utility's particular situation.

4
TECHNOLOGY DESCRIPTION

The prior section described creating basic overview documentation of a Smart Grid demonstration project, useful with management, regulators, or with later post-demonstration documentation. This section continues with a second level of documentation that delves into greater detail on the technologies being deployed in the project and what they are expected to do when deployed. The term *technology* is used here in the broadest sense to include devices and equipment, information, and even commercial terms of service like pricing structures or other behavioral inducements.

Specifically, we will examine the list of functions that the technology enables, but will then narrow down the focus to only those functions being activated in the specific application under evaluation. After all, some devices have many potential uses, but they may not all be applicable in a single deployment in a specific context. The CBA will examine the specific application being tested, to the exclusion of functions not being applied. The ultimate aim is to capture monetized results, whether costs or benefits, that the Smart Grid application provides, but the process to arrive at benefits must pass through the specification of the physical and measureable impacts expected. This section will step through the mapping out this sequence from devices and systems to monetized costs and benefits, tracing through measurable impacts.

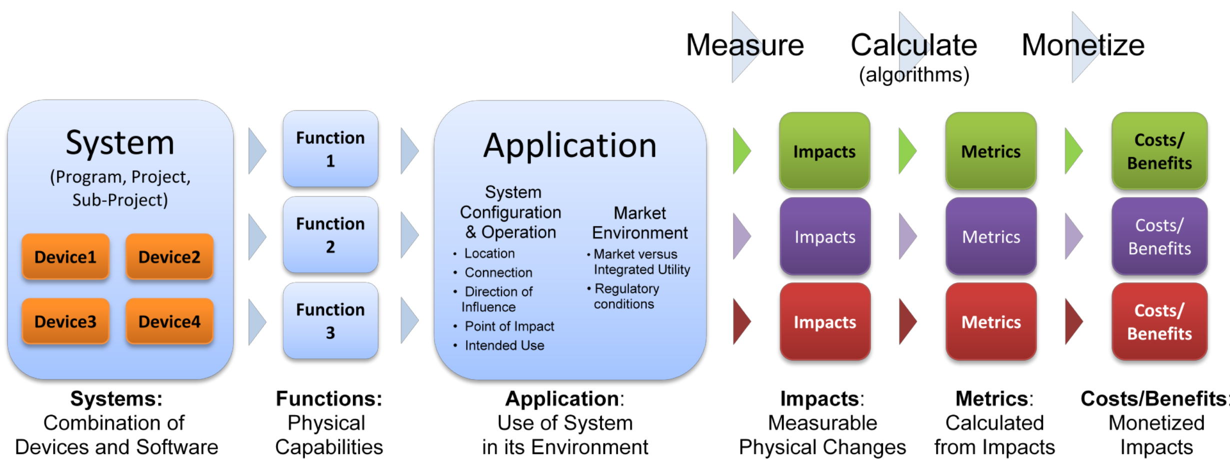


Figure 4-1
Terms Connecting Technologies to Benefits

Figure 4-1 depicts a process starting from specifying devices and systems (technologies) to the benefits they are expected to provide. The process in real implementation is not always so linear, and often difficulties are encountered in determining a baseline measurement for an impact determination. The framework is mainly useful for illustrating the terminology that will be used subsequently.

Terminology

Devices and systems – Devices are individual identifiable components that perform a function as a part of a system with other devices. A Smart Grid device is itself likely to be a system composed of component devices, but the relevant level here is large devices such as sensors, switches, radios, controllers, etc. The Smart Grid project is likely to contain a collection of such devices connected so as to communicate and operate as a system. A system is a group of devices that performs a set of complex functions reflecting the joint action of its component devices. Because of the overlapping nature of devices, systems, and sub-systems, there is no point being overly precise pulling every device apart. The term "technology" applies to them all.

Functions – Functions are the physical capabilities of the system, at a high level, that are available for use. Functions may not all be applied simultaneously in every situation, however.

Application – An Application is a selection of functions for a given system configuration and system context. A CBA based on measurement data in a demonstration project is necessarily confined to the specific application, which may include only a subset of the total array of possible functions the system can deploy.

For example, a storage unit might be applied to smooth the output of a photovoltaic unit, or the same storage unit might be applied to sell reserve capacity in the local market. Those are two separate value propositions for the same device/system. If the unit is applied to smoothing, the reserve capacity function is inert, and vice versa. A trader responsible for the unit might want to choose between functions on the fly, but that is yet a third application to be considered. The point is that a CBA is specific to the use selected, and doesn't include every enabled function unless they're going to be active.

Impacts – The physical *changes* brought about directly by the system are impacts. Impacts are derived from measurements because they are changes, i.e., differences in two sets of measurements. The reference point is a measurement or estimate from the baseline scenario.

- Direct or primary impacts are generally confined to the project area. For example, loss reduction within the project area may be a direct impact of a Smart Grid application.
- Indirect or secondary impacts are physical changes that may be outside of the project area, or that may be derived from other measurable direct impacts. They may be impractical or impossible to measure, and must be estimated. A primary impact of loss reduction may in turn cause a secondary impact of reducing fuel use and emissions out on the power system. Such secondary impacts are generally estimated, not measured.

Metrics – Metrics may be the same as impacts, or may be calculated from measurements and impacts using algorithms. An example of a metric is SAIDI, a reliability index, which is calculated from Customer Minutes of Interruption, a measurable quantity. A change in interruption minutes is a physical impact which can be converted to a change in SAIDI. The distinction is important only in that impacts are based on measurements, while impact metrics may be a step removed from measurements by way of calculation.

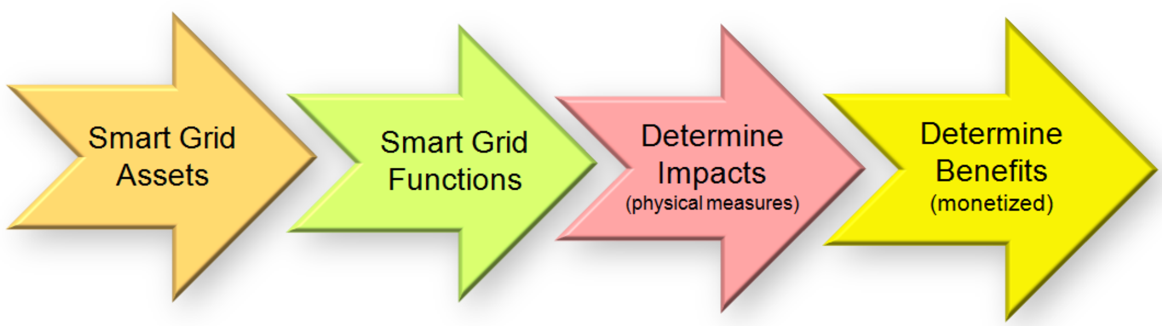
Benefits – Benefits are either monetized impacts or other non-monetized secondary impacts. A reduction in losses is not itself a benefit. The benefits of loss reduction are reductions in fuel use and emissions, both of which can be monetized from estimated secondary impacts.

Impact-Related Costs – Not all monetized impacts are benefits; some may be impact-related costs (separate from the cost of equipment, installation, maintenance, etc.). Impact-related costs are any costs caused by the operation of the equipment. If, for example, the equipment will chronically raise the voltage on a substantial number of customers relative to the baseline scenario, then any increases in losses or customer loads related to the higher voltage are impact-related costs. All impacts that result in costs or benefits experienced by customers or the utility should be captured and included in a CBA.

To summarize the terminology: We *measure* primary impacts, *calculate* impact metrics, calculate/estimate secondary impacts, and *monetize* those impacts and metrics to produce costs and benefits. Some estimated secondary impacts may not be monetized, perhaps for inclusion in a qualitative combination of characteristics. Figure 4-2 provides examples of these various quantities.

Technology Description Process Steps

These process steps in this section are preliminary to experiment design, which is intended to isolate measurements that can describe the project impacts. Formality here provides some standardization, in hopes that many projects can be understood within the framework using a standard terminology. Here we lay out the conceptual CBA process from assets to costs and benefits, to determine the physical measurements from the demonstration project necessary for the CBA. In the next section we concentrate on setting up the experiments that can produce the required measurements.



Technologies, Devices, & Systems

Examples:
- AMI/Smart meters
- Distribution Automation
- 2-way communication
- Smart Appliances
- Intelligent Electronic Devices (IEDs)

Systems' Intended Functions

Examples:
- Volt/VAR control
- Dynamic Capability Rating
- Flow control
- Intelligent line switching
- Real-time load management

Project performance relative to baseline scenario

Example measures:
- kWh reduction
- Peak kW reduction
- Loss reductions
- Outage reductions
- Improved asset utilization

Monetization of Impacts

Example metrics:
- Fuel savings
- Capacity savings
- Reduced outage costs
- Reductions in CO_2, Hg, etc.

Figure 4-2
Examples of Systems, Functions, Impacts, and Benefits

The process begins by listing and describing the technologies employed and the functions they provide. The functions are linked to benefit areas in the tables provided in the steps below, and these benefits may be the easiest way to describe what the projects are for, especially to non-technical people. However, the CBA process for demonstrations, as described above and diagramed in Figure 4-2, requires linking the benefits with physical impacts, which must be measured and verified in experimentation.

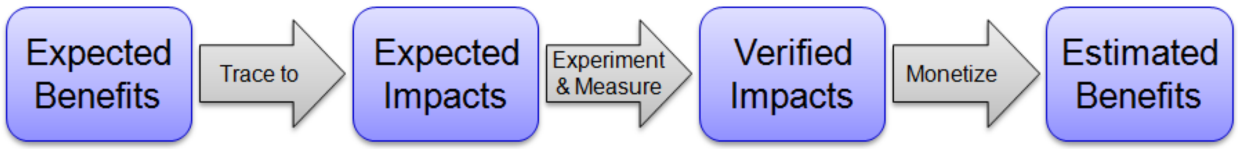


Figure 4-3
Linkage of Expected Benefits to Estimated Benefits in the CBA through Experimentation to Verify Impacts

Whatever benefits result from a Smart Grid project must trace to physical impacts that occur within the area of the project. Physical impacts may ripple out beyond the project area in lengthy causal chains that become untraceable, but they begin with impacts within the area influenced directly by the project and within the confines of the experiments, subject to some form of measurement. The exercise in this portion of the process is to trace through the causal chains from first-cause impacts to the ultimate, monetizable impacts, while recognizing again that some of the impacts may lead to costs.

In the next section, we will describe the research problem, which is to design the experiments to measure and verify impacts against a set of baseline assumptions consistent with the baseline scenario.

Step 5 Describe the technologies, devices, and systems to be deployed in the project.

Conceptually we may not need a lengthy list of minor Smart Grid devices in order to link to functions, but such lists will clearly be needed for estimating the cost of equipment and deployment for feeding into the cost/benefit analysis. Examples are shown in Figure 4-2. Include here any customer-interaction means, including pricing, that will be implemented as part of the project. While these are not assets per se, they are important technologies being tested as functionalities enabled by Smart Grid assets such as smart meters. The following list of Smart Grid assets was provided in the Methodological Approach (p 4-4), but it is not exhaustive. Users of the process are encouraged to add or substitute technologies or terminologies that fit the demonstration project and its stakeholders. What is important is that they are described in a way that leaves no ambiguity as to their purpose.

- Advanced Interrupting Switch
- AMI/Smart Meters
- Controllable/regulating Inverter
- Customer EMS/Display/Portal

- Distribution Automation
- Distribution Management System
- Enhanced Fault Detection Technology
- Equipment Health Sensor
- FACTS Device
- Fault Current Limiter
- Loading Monitor
- Microgrid Controller
- Phase Angle Regulating Transformer
- Phasor Measurement Technology
- Smart Appliances and Equipment (Customer)
- Software - Advanced Analysis/Visualization
- Two-way Communications (high bandwidth)
- Vehicle to Grid 2-way power converter
- VLI (HTS) cables

Step 6 Describe the Smart Grid Functions enabled by the systems deployed in the project.

A list of Smart Grid Functions was provided in the Methodological Approach (pp 4-4 and 4-5). This is not an exhaustive list, and users of the process are encouraged to add other functions that may arise from their projects, or to substitute terminology appropriate for the project and its stakeholders.

- Fault Current Limiting
- Wide Area Monitoring and Visualization and Control
- Dynamic Capability Rating
- Flow Control
- Adaptive Protection
- Automated Feeder Switching
- Automated Islanding and Reconnection
- Automated Voltage and VAR Control
- Diagnosis and Notification of Equipment Condition
- Enhanced Fault Protection

- Real-time Load Measurement and Management
- Real-time Load Transfer
- Customer Electricity Use Optimization

These functions are defined and described in more detail in Table 4-2 of the Methodological Approach (pp. 4-6 through 4-8), provided here in Appendix B. Demonstration project documentation should include these or similar descriptions of the functions provided by the project. The description of functions may extend beyond what is going to be applied and tested in the current project, but those functions enabled but not applied should be clearly delineated as latent future possibilities or unused functions, so as to avoid setting unrealistic expectations.

Linking of Assets to Functions

A table linking the provided asset and function categories is given in Table 4-1, suggesting of the one-to-many relationship between some assets and their associated functions. Users of the process should consider this table extensible in both dimensions, and the associations are malleable as well. To improve its use as a communication tool, the table can be trimmed to only those parts applicable for the demonstration project or project area.

Step 7 Describe how the deployed Smart Grid devices and systems will be applied.

This step should narrow down the list of functions that the technology could perform to only those being applied in the demonstration project. This is an important step, as the cost/benefit analysis should be for the Smart Grid equipment as it will be applied, not as it has the potential to be. Also, this step leads to developing experiments to measure and describe the performance of the technology in this application.

The description should begin with the functions described in the previous step, and should describe in more detail how they are to be used and applied.

- Under what circumstances will the equipment operate? Will it operate all of the time, or will it be used only in case of certain conditions, e.g., only on peak. Will it be reserved for emergency use? Or will it be operated routinely on peak? For how many peak days?
- Will storage equipment be operated to provide routine ancillary services? Will it be reserved for local reliability? Will it be used for smoothing of nearby intermittent resources?
- If the equipment has several selectable control schemes, how will the schemes be selected operationally? Will one scheme be used routinely, while another becomes active in emergency or peak conditions?

Such questions determine which sources of potential value are to be tapped, versus those that are to remain latent. Likewise, it determines which phenomena must be tested and measured in experiments, versus those that are no longer important.

Table 4-1
Linkage of Assets to Functions

Smart Grid Assets	Functions												
	Transmission		Distribution						Substation			Customer	
	Flow Control	Wide Area Monitoring and Visualization	Adaptive Protection	Automated Feeder Switching	Automated Islanding and Reconnection	Automated Volt/VAR Control	Enhanced Fault Protection	Real-time Load Transfer	Diagnosis & Notification of Equipment Condition	Dynamic Capability Rating	Fault-Current Limiting	Customer Electricity Use Optimization	Real-time load Measurement and Management
Advanced Interrupting Switch							●						
AMI/Smart Meters						●						●	●
Controllable/regulating Inverter					●	●							
Customer EMS/Display Portal												●	
Distribution Automation			●	●	●	●		●					
Distribution Management System			●	●	●	●		●		●			●
Enhanced Fault Detection Technology							●						
Equipment Health Sensor									●	●			
FACTS Device	●												
Fault Current Limiter											●		
Loading Monitor								●	●	●			
Microgrid Controller					●								
Phase Angle Regulating Transformer	●												
Phasor Measurement Technology		●											
Smart Appliances and Equipment (Customer)												●	
Software – Advanced Analysis/Visualization		●								●			
Two-way Communications (high bandwidth)		●	●	●	●	●		●					●
Vehicle to Grid 2-way power converter													
VLI (HTS) cables	●												

Step 8 Describe the benefits and impact-related costs expected from the project when it is applied as described in the previous step.

Recall the discussion above concerning direct and indirect impacts, and the distinction we are drawing here between impacts, benefits, and metrics. Benefits (and impact-related costs) are generally monetized, i.e., expressed in a currency such as dollars, though some benefits may be left in physical form for inclusion in qualitative ranking of alternatives. Benefits (or costs) may occur distant from the project, in the way that reductions in loads and losses in a particular locale may affect generator dispatch elsewhere.

Just as the CBA is for the project's specific application, and not for the technology in general, the benefits listed in this step are intended to be all-inclusive, but specific to the application of the Smart Grid technology in this demonstration project. However, every effort should be made to anticipate all benefits and impact-related costs before designing the experiments so that all of the necessary impacts can be captured during the demonstration.

The Methodological Approach defined a list of standard benefit categories (pp 4/15-18), which are replicated here in Table 4-2, along with suggested linkages with the list of Smart Grid functions. The definitions are replicated in Appendix B of this guidebook. This list of benefits was jointly derived with the U.S. DOE, and is the basis of standard reporting requirements for DOE-funded projects. The linkages shown here are, of course, not application-specific; some linkages may be inactive or negligible in some applications. The linkages of functions to benefits implied by the dots in the table are the same as in the Methodological Approach, but there may be other linkages that have been brought about in the meantime.

The list of benefits shown is unchanged from its original version, where most of the benefits refer to easily recognized physical links in the causal chain from impact to true monetary benefit. Our terminology has evolved in the ways mentioned above, in that we have separated physical impacts from monetary benefits, and the monetary benefits may be legion when calculated in all their various components. All such benefits can be mapped into these categories for the purposes of comparison across projects or reporting to DOE.

As an example, consider an installation of Distribution Automation equipment consisting of reclosers, switches, a controller system, sensors, etc., with the primary function of Fault Location Isolation and Service Restoration (FLISR) following sustained faults. The FLISR function is not a smooth fit into any of the original Smart Grid functions, but it can easily stand alone as a Function. The primary benefit of FLISR is "Reduced Sustained Outages." More precisely, FLISR reduces the number of customers abiding sustained interruptions, meaning interruptions of 5 minutes or more in duration. In our revised terminology, this is actually more of an impact. The major benefit of FLISR is reduced customer-cost of interruptions, a monetary equivalent that can be estimated.

Table 4-2
Benefits Linked to Smart Grid Functions

Benefits			Functions: Trans-mission		Distribution						Substation			Customer		Energy Resources		
			Flow Control	Wide Area Monitoring & Visualization	Adaptive Protection	Automated Feeder Switching	Automated Islanding and Reconnection	Automated Volt/VAR Control	Enhanced Fault Protection	Real-time Load Transfer	Diagnosis & Notification of Equipment Condition	Dynamic Capability Rating	Fault Current Limiting	Customer Electricity Use & Optimization	Real-time Load Measurement and	Distributed Generation	Stationary Electricity Storage	Plug-in Electric Vehicles
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						●		●				●	●		●	
	Electricity Cost Savings	Reduced Electricity Cost												●			●	
Reliability	Power Interruptions	Reduced Sustained Outages			●	●	●		●		●				●	●	●	●
		Reduced Major Outages		●			●								●			
		Reduced Restoration Cost			●	●			●		●							
	Power Quality	Reduced Momentary Outages							●	●							●	
		Reduced Sags and Swells							●								●	
Environ-mental	Air Emissions	Reduced CO_2 Emissions	●			●		●						●	●	●	●	●
		Reduced SOx, NOx and PM-10 Emissions	●			●		●						●	●	●	●	●
Security	Energy Security	Reduced Oil Usage (not monetized)				●					●				●			●
		Reduced Wide scale Blackouts		●					●			●						

Step 9 **Describe the physical impacts and performance metrics that would be needed to analyze the performance of the project and to calculate the various benefits listed in Step 8.**

This important step, working backwards from benefits or costs to the impacts that produce them, will lead directly to experiment design to measure the required impacts. Where benefit calculations depend on intermediate performance metrics, work backward from the metrics to the primitive impacts measurements needed for calculating the metrics.

Referring back to a prior example, SAIDI and MAIFI are common reliability performance metrics that are not measureable. The primitive impact used to calculate SAIDI is Customer-Minutes of Sustained Interruption, which can be measured, and for MAIFI, a count of Customer-Interruptions Momentary.

5

DEVELOPING A RESEARCH PLAN

This section describes the process of creating a research plan for measurement of the impacts of a Smart Grid demonstration project. We follow the steps of the Scientific Method in order to produce credible and reproducible results that demonstrate the impacts of the Smart Grid systems. The impacts will feed into the Cost/Benefit Analysis, driving monetized benefits and impact-related costs, though monetizing impacts is not part of this research step.

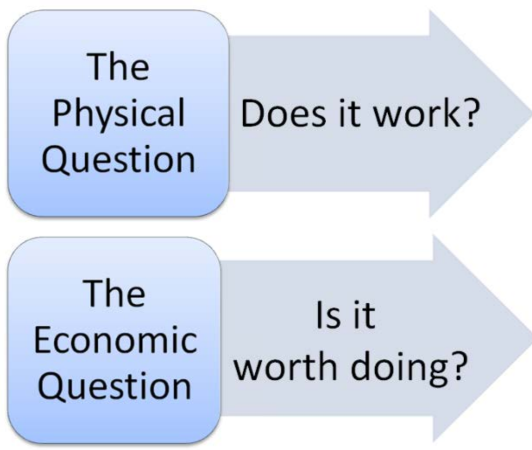


Figure 5-1
The Two Major Questions Addressed by the Process

The Research Problem for the demonstration project is mainly associated with the Physical Question: To what extent does the Smart Grid application perform? Answering this question is essential to subsequently answering the Economic Question: Does that performance justify the cost? However, the answers to the Economic Question are substantially more subjective than the physical measurements, and less likely to be shared in detail.

Stacking/Layering of Project Steps

At this juncture it is time to consider that the single project may incorporate a number of steps, each of which may present legitimate physical and economic questions. In addition, a project may consist of components that can be broken down into sub-projects. These projects must be examined separately, and if their impacts interact in any way, they must be examined both separately and together. The cost/benefit analysis, then, may fracture into a series of questions in which sequence is likely important.

- Is there a logical first step that has impact? How much of the impact and how much of the benefits come with this first step? How much does the first step cost to implement?
- Is there a logical second step? How much does this second step cost to implement, and how much impact and benefit comes with the second step?
- And so on.

It may be useful to think of these steps as successive stacked layers, where each step of the process constitutes a new ground on which the next step is built. Figure 5-2 depicts such a hypothetical stacking of portions of a project over the baseline scenario. This sequence of steps culminates in a centralized control system optimizing control of capacitors on a circuit, but it poses questions about each of several steps. The first step is a process of manual balancing load among phases, an activity that logically precedes the placement of capacitors for controlling var supply and regulating voltage. Both steps reduce losses, but only if they are treated and measured (or modeled) in sequence can we determine how much loss reduction to attribute to each step. The final step adds a centralized control system that coordinates the capacitor switching, improving the performance of the system over that achievable with just the local controls installed with each bank of capacitors. The last step determines the efficacy of the control system to improve performance, and evaluates its economics apart from that of the capacitors and the phase balancing. The entire stack could be analyzed as one project, but this approach answers more questions, focusing the physical and economic questions toward the individual steps of the project.

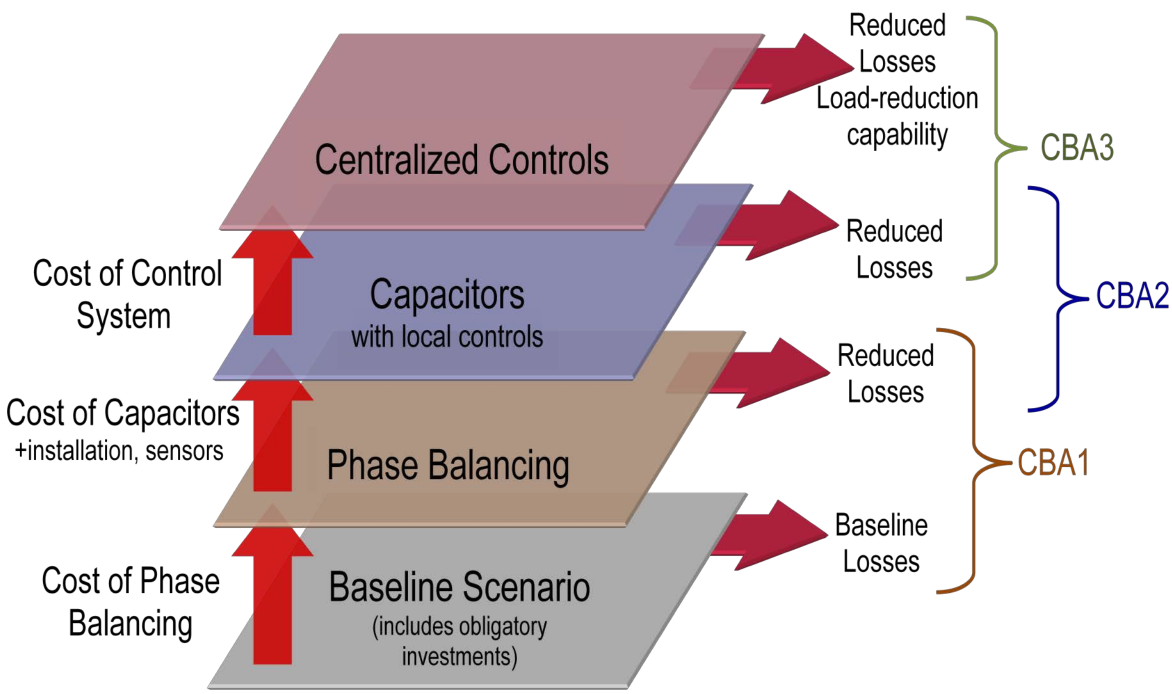


Figure 5-2
Stacking/layering of portions of a project to isolate a series of physical and economic questions

There may be alternative approaches to addressing the initial problem. Naturally, a cost/benefit analysis of one solution relative to the baseline does not resolve whether that solution is better than any other. To properly address a decision among two alternatives requires analysis of both alternatives separately.

The Research Problem, then, is to measure the physical performance of the Smart Grid application such that its performance can be quantified and described with sufficient certainty and accuracy. However, the research problem should be broken down into sub-problems sufficient for answering the relevant physical and economic questions that a thorough analysis would demand.

Baseline Quantities

Beginning in Step 2 we began describing a baseline scenario, that is, the scenario we will use as a basis of comparison to determine the relative costs and physical impacts, and subsequently benefits associated with the Smart Grid application. To this point, the baseline scenario may consist of only a qualitative description, but now we must establish numbers or measurements for comparison purposes that are consistent with this baseline scenario. This may not be a simple exercise.

Let us distinguish between the Baseline Scenario and the baseline quantities. The Baseline Scenario extends into the future, a planner's view of what would have happened but for the project being considered. It may include future upgrades or reconfigurations. Its upgrades or changes may imply impacts extending beyond the project area. We will likely need to forecast impacts, costs, and benefits into the future for the baseline scenario as well as the project scenario. The baseline *quantities*, on the other hand, are mainly concerned with the experimental measurements. All are within the project area and within the period of the demonstration. They are specific quantities that we must measure or estimate in order to determine or estimate the impact of the project. For every impact quantity, there should be a set of with-project measurements and a set of no-project baseline measurements or estimates.

Why must baseline quantities be *estimated*, rather than *measured,* for demonstration projects? In some experimental settings, researchers and scientists may be able to establish or replicate conditions such that baseline measurements can be made simultaneously, side-by-side, or under essentially the same replicated conditions as those of the experiment. However, because smart grid demonstrations take place on real power systems with real consumers experiencing variable weather, no instant of time can be physically replicated. A baseline measurement under the same conditions is not possible, and can be only estimated. Installation of the Smart Grid application may reconfigure the system such that the original condition may no longer be available, even by switching the new equipment out of service. History is sometimes used to establish a baseline, but this can be misleading unless the quantity is very stable over time. Baselines can sometimes be established by replicating the measured conditions as closely as possible in software models, which may also be useful in estimating quantities that are difficult to measure in any case, such as losses. Models can also be useful for reconstructing performance of a system responding to an event, but with the system configured as it was before the demonstration. In short, great care is required to establish baseline quantities for estimating the impacts of Smart Grid applications.

Stating hypotheses to drive experimentation

Our purpose in stating hypotheses for smart grid demonstration projects is to focus attention on designing experiments to isolate and measure quantities that demonstrate the impacts of the smart grid systems. However, constructing hypotheses can seem awkward for people not accustomed to experimental science. It may seem unnecessary, especially if all we want is to make a simple measurement of a device operating in the field. However, the process of forming well-structured hypotheses can provide focus to help avoid issues that can render results invalid.

A hypothesis is a provisional statement whose truth is to be tested by experiment. A simple hypothesis can be supported or falsified by experiment, so logically a hypothesis of a provisional truth (an "alternative" hypothesis) comes paired with a corresponding "null" hypothesis describes the alternative outcome. Experiment should decide which of the two is supported by the evidence. A complex hypothesis may break down into multiple sub-hypotheses, becoming more specific and bounded as to eventually be testable in experiment. Experiments supporting the sub-hypotheses can ultimately establish a basis to support the complex hypothesis.

The CBA process is intended to first establish the physical impacts, and then form the associated economic value proposition. Load reductions, for example, do reduce fuel use and probably reduce emissions, and these are benefits we want to capture in cost/benefit analysis. But load reductions can be measured within an experiment, while fuel-burn and emissions reductions are generally outside of the bounds of the experiment and not amenable to measurement. Hypotheses suitable for experimentation should be decidable fully within the bounds of the experiment, which may involve one or more feeders or substations or groups of customers. The hypothesis should not extend into the analytical steps that may follow in the cost/benefit analysis.

The purpose of experimentation in smart grid demonstrations is to produce valid impact measurements. The discipline of the scientific method is employed to support validity of the result. Going into an experiment we hypothesize the existence or direction of an expected physical impact, not yet knowing its amount. This initial hypothesis may seem to be a trivial true/false hypothesis, but impact measurements are not always straightforward, and on real distribution feeders they may be encumbered with unexplained random variations. The experiment will generate measurements that will allow post-experiment hypothesis testing. The measured impact, if verified apart from a chance result, then is used to establish the associated costs and benefits.

A well-formed, pre-experiment true/false hypothesis statement, therefore, should not contain an estimate or guess of a measurement that will take place in the experiment *unless the value implies something specific enough to verify or falsify the hypothesis*. The sensitivity of load to voltage provides a good case in point.

- Theory tells us that for a linear resistive load, each reduction of 1% in applied voltage will result in a 2% reduction in power consumed. To test whether that statement is true, we could set up a laboratory demonstration and take measurements. If we measure 2% with calibrated equipment, our measurements support the theory, i.e., they are consistent with Ohm's Law. If we measured 1%, then we disagree with Ohm's Law, but much more likely we have made a bad measurement or assumption. The point is that we have a theory that predicts a particular result, 2%, and we can make measurements that either support or falsify the theory. A hypothesis for that experiment might state the 2% expectation, based on theory.[7]
- Theory leads us to expect that reducing average delivery voltage on a feeder will reduce feeder load by some amount less than what Ohm's Law states because we know that different loads respond to voltage changes differently. Feeders have different concentrations of installed load types, and the mix of loads actually drawing power varies by time of day. From theory, we expect no more than 2% load reduction per 1% of voltage reduction, but we have no reason to expect that maximum result. To determine the sensitivity of a feeder's load to its voltage, we must take measurements. In this case, the hypothesis tested by experiment is simply whether a particular feeder's load responds to a reduction in voltage, true or false.

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[7] We can legitimately question how close to 2% the result has to be before it disagrees with theory. Deviations from 2% demand explanation, if only to examine measurement and device tolerances.

Formal testing of the hypothesis requires the measurements we will subsequently need in the CBA. The point is that if we have no reason to expect a particular numeric result then there is no reason to hypothesize one.[8]

Most smart grid demonstrations will be in the second category. That is, there will be smart grid equipment that performs designed and tested functions, and the experiments will be intended to measure its impact on the electric system. We may expect a particular result from experience or guesswork, but there is no need to hypothesize and confirm it.

Some experiments on first-of-kind equipment may be oriented toward confirming the design specifications of the equipment. In these cases the hypotheses may be stated in terms of the specific design specifications.

Hypothesis testing

Verifying a result requires that the measured result be distinguishable from chance variation. In some conditions, chance variation may be very small relative to the quantities being measured, such as with the laboratory measurements of electrical phenomena imagined above. However, in other situations random variations may be substantial relative to the quantities being measured, requiring analysis to verify the result. In measuring the impacts of smart grid devices, there may be two measurements that must be made, and both are usually subject to the same kinds of random variations.

In population sampling studies, where behaviors are compared among two or more groups of people, the mean and variance of a random control group allow some inference about the population and the variance of the population on that measure. A second random sample would not measure exactly the same as the first, but statistics tells us what we can expect of the second random sample in terms of how close it should measure to the first. We can use this expectation to determine if a treatment changes the behavior of one random sample relative to the other. In the smart grid arena, tests of this type are required to test measurements of human responses to time-varying rates, for example.

We have similar issues even when we measure physical quantities on distribution feeders, mainly because we cannot measure two conditions on the same feeder at once. In a sort of uncertainty principle, we can measure a quantity when affected by a treatment, but we cannot know what the quantity would have been without the treatment, or vice versa. We cannot simply make measurements with and without a treatment, because background conditions are changing all the time. If the impact, the change we are trying to measure, is within the range of the random background variations, then we are tasked with extracting an impact that is difficult to distinguish from chance. We can "explain" some of the background variations with statistical analysis, but in some cases the unexplained variations are still in the same size range as the impacts. In these cases, a lot of experimental replications are required to isolate the separate effects to a acceptable level of significance.

[8] We could hypothesize "less than 2%" to comport with the theoretical result, but why bother? The point is not to prove "less than 2%" but to find an impact by using measurements to estimate its value, which had better be less than 2%. In some times of year the impact may be so small as to be indistinguishable from zero using regression analysis.

A common measurement problem in smart grid demonstrations is the impact of voltage reduction on feeder loads, as in the example above. A common approach is to measure loads over a period of time while alternating the voltage level between normal and reduced levels for 24-hour periods. Regression analysis (a proxy of a formal statistical test) is used to explain as much normal daily, weekly, and hourly variation as possible so that the impact of the voltage variation can be estimated. However, the impact is small and within the range of the unexplained hourly variations. The hypothesis for an experiment in voltage reduction is that voltage reduction measurably reduces load and losses on a particular feeder. Methods of analysis vary, and no standard method of significance testing has been developed. The development of standard protocols would improve the results of any field trial and facilitate comparisons across experiments.

Another common measurement is feeder reliability with distribution automation equipment. Here the project must wait for faults to naturally occur in order to measure the performance of the equipment. The hypothesis would be that distribution automation equipment reduces customer-time of interruptions. The problem, however, is again the scenario against which an impact can be measured. Measurement against history would require evaluation of the historical variation in the measurement. Over time, continued improved reliability performance would be verified if it was not consistent with the historical mean and variance, with perhaps some allowance for a trend if one was evident. This may take several years to establish. Shorter-term estimations of impact can be accomplished by establishing the counterfactual performance of the pre-treatment system when exposed to the same faults, which are not affected by the presence of distribution automation equipment.

In summary, for smart grid demonstration purposes, hypotheses should be:

- True/false statements relating actions of smart grid applications to their physical impacts
- Testable by experiment
- Resolved by measurements taken within the bounds of an experiment

Experiment Design

As suggested by Figure 5-3, the setting of hypotheses precedes and drives experiment design. That is, the hypothesis makes a testable statement, the experiment is designed to test the statement to either support or falsify the hypothesis.

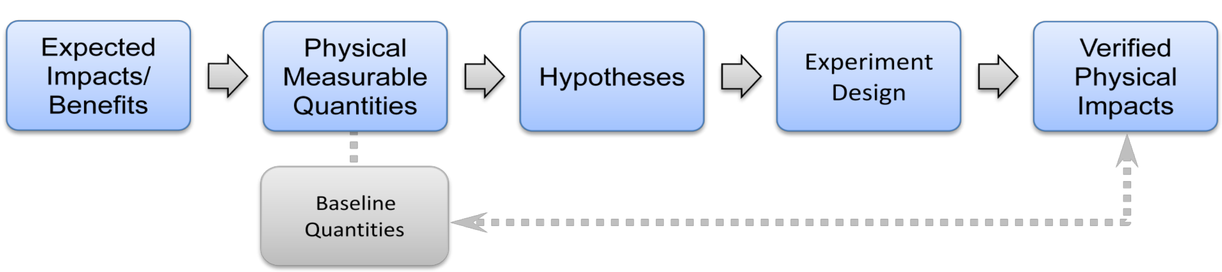

Figure 5-3
Hypotheses Precede and Drive Experiment Design

As discussed above, a complex hypothesis should be broken down into relatively simple sub-hypotheses, with only one impact to verify. Each sub-hypothesis should be decided by one set of experiments, so a list of sub-hypotheses implies a list of experiments that will take place in sequence.

Step 10 Define the Research Problem

As stated above, the Research Problem is a question that will be addressed through the demonstration project. Generically, the primary research problem can be expressed as "How does the [Smart Grid application] impact the [power system/feeder]?" Expected impacts were listed in Step 9, but this step describes the process of actually measuring those impacts, and also of structuring the cost/benefit analysis.

Since impacts may be multiple and/or multi-dimensional, the primary research problem may break into a series of individual questions or sub-problems. The researcher must analyze these questions to determine whether they can be measured and examined independently or whether they must be addressed in sequence. These considerations are a part of the research problem, and should be described fully in this step.

Step 11 Identify the physical measurements that will be needed

Physical measurements taken within the bounds of the Smart Grid demonstration project will be used subsequently to estimate the impacts of the project on the relevant sections of the power system. The impacts will be monetized either as benefits or as impact-related costs.

The expected impacts were listed in Step 9. In this step the physical measurements required for evidence to quantify these impacts are listed in some detail. Many Smart Grid devices have the capability of generating measurements, and the entire set should be examined to determine what measurements are available without further placement of sensors. Work through in detail how various measurements could be used to calculate impacts, as the needs of the calculation algorithms may affect the choices made in terms of what data to collect and how often to collect it.

Step 12 List relevant external factors and whether they will be measured/collected.

Some external factors are vitally important to analyzing measurement data. For instance, weather information such as temperature, humidity, or insolation may be important for analysis of consumption data. Weather data should preferably be measured in the vicinity of the project area, though some hourly weather data are available from various sources. Measuring these quantities as part of the project can provide data with exactly the characteristics needed, rather than having to accept the measuring points, completeness, precision, and uncertainty of the timing of measurements from another source.

Precision of non-electric data, especially with regard to simultaneity, may be unimportant for some types of projects, but for others these data quality issues may be important for establishing confidence in results. For instance, the kW impact of Conservation Voltage Reduction is small relative to the measured feeder load, and must be detected using regression analysis in which weather data plays an important part. In fact, any non-weather factors that may affect feeder loads at various times of year may also be significant. For instance, school and government holiday schedules can affect load shapes on residential and commercial feeders, likely to a greater extent than Conservation Voltage Reduction on the days when they occur. Such information can easily be figured into regression analysis if it is made available, or ignored if useless. The person who ultimately does the analysis will likely prefer more relevant data items to fewer, while finding limited use for very short-period measurements, such as one-minute intervals.

Step 13 Define the baseline quantities or methods of estimation

Beginning in Step 2 we began describing a baseline scenario, that is, the scenario we will use as a basis of comparison to determine the costs, impacts, and benefits associated with the Smart Grid application. The baseline scenario may be a qualitative description to this point, but now we must find a set of numbers or measurements for comparison purposes that are consistent with this baseline scenario. This may not be a simple exercise.

For every physical measurement that is expected to have an impact from the Smart Grid application, there should be a baseline quantity or an explanation/methodology for how the baseline will be estimated. As noted above, Smart Grid demonstrations are taking place in the field, not under highly controlled test systems where conditions can be replicated and external influences nullified. Often, the installation of a Smart Grid application precludes measurement of the system in its former state, and each moment of time is unique.

In some cases the baseline itself may not be derived or estimated as a standalone value, but its presence may be implied by the analysis that detects and estimates the impact. In the case of regression analysis to extract the impact of Conservation Voltage Reduction from a series of on/off observations, the baseline is usually implicit in the regression analysis, although a baseline could be produced from the analysis if required. With other technologies[9] the measured loads can be replicated in circuit models that can simulate the response of the original system, providing a basis of comparison from which an impact can be estimated.

This step, then, is not generally a listing of baseline measurements, but a description of the methodology used to estimate the baselines or the impacts. The selected methodology may dictate the kinds of data needed, and may provide practical limits to measurement periodicity.

[9] Models of feeder loads' response to voltage variation have not yet been developed sufficiently for adequate model-based estimation of voltage reduction impacts. The voltage sensitivity of various individual devices can be measured in the laboratory, and these devices can easily be modeled. However, the composition of loads on a feeder at any point in time is unknown.

Step 14 Construct formal hypotheses to be tested through experimentation

As discussed above, the hypotheses should be true/false statements about impacts associated with the Smart Grid application. The hypotheses should be testable by experiment, and should involve only physical, measureable quantities within the bounds of the project. Complex hypotheses that involve multiple steps or quantities should be broken down into simple statements involving one step and/or one quantity. The hypotheses should not extend into the economic analysis. The application may reduce cost in the end, but cost reductions result from some physical impact. The hypothesis should concern the physical impact, not the costs that change.

Hypotheses should be listed for every impact quantity necessary for translation/monetization into the expected benefits of the application. The tracing from expected benefits, to expected impacts, to verified impacts, to estimated benefits should be planned out in advance so that needed measurements are not missed.

Step 15 Specify the experiments and how they will be conducted.

The intent of experimentation is to verify the hypotheses and to produce measurements that will provide estimates of the impacts of an application after it has been deployed. Experiment descriptions should be complete as to the quantities they are intended to measure and how the impacts are intended to be extracted from the measurements. *Note that some impacts vary across the year, and that measurements taken in one part of the year may not apply for other times of year. The experiment plan should be examined by analysts as well as engineers, who must agree on the needs and purposes of experimentation.*

Step 16 Develop a detailed project timeline around the experiment plans

The project timeline should include the design and engineering time, equipment testing time, deployment, field testing, and then the schedule for experimentation and measurement. Time for analysis and reporting should also be included, along with interim reporting as required by management, government, or regulatory bodies. This timeline is conventional project planning, constrained by deadlines and the time required to complete certain tasks. However, within the times allotted to experiments, a detailed schedule for experiments of various types must be laid out. The time allowed for experimentation may seem short once competing needs are revealed, especially if it must be confined to a peak season. The schedule of events should be examined by all parties that will are needed for participation, including those who will need to analyze the data.

Step 17 Provide data collection instructions, including collection points and time intervals for each measurement

Smart Grid devices often have the ability to provide measurement data. These may be sufficient for analytical use, but their location on the system is a consideration. Modern substation transformers and breakers often have a variety of measurements available. For some calculations, however, a load-weighted or customer-weighted average feeder voltage may be preferable to breaker voltage. In that case, voltage readings from selected points along a feeder may provide a basis for average-voltage calculations. And in some situations, voltage data from customer-premises meters may be available for calculations.

Among the necessary details is the periodicity of the physical measurements, i.e., how often measurements are to be taken. For many calculations, hourly data will suffice, but data may be available over shorter intervals. Fifteen-minute interval data are common, but the analyst may quickly sum/average to hourly data for analysis. One-minute data could be useful for examination of short-term transient changes, or event analysis, but may far exceed what is necessary for estimating losses or load/voltage sensitivity. A consideration with such measurements, however, is what a time-stamped measurement means. Is it an instantaneous reading or is it an average over the period from the previous time stamp? The longer the measurement period, the more this is a concern. Also, the more volatile the measured quantity, the more of a concern. A time-stamped demand should logically be the average demand from the prior time stamp. Temperature measurements are more likely to be instantaneous, but then it is not as volatile as demand. Voltage is quite volatile on many circuits, so average period voltage would be preferable to instantaneous. In any case, the trade-offs of periodicity should be considered in the context of the needs of the analysis.

Along with contemporaneous measurement data, any relevant events such as reconfigurations, faults, trips, or blown fuses should be recorded as well. These may be available through an outage management system, but arrangements should be made to receive the data if needed for analysis. These events may invalidate data for a period, but they may also be incorporated in the analysis in various ways.

When all uses of data have been reviewed by all potential users of the data, data collection instructions must be provided to the proper information technology personnel on the implementation team so that the needed data are collected and stored for the experiment period.

Step 18 Specify data testing, screening, storage and retrieval protocols

Arrangements must be made with the information technology personnel as to storage and retrieval of data from the Smart Grid demonstration project. If possible, testing and screening of data on a short-cycle repetitive schedule should be automated so that out-of-bounds data conditions can be identified promptly. Drop-outs of data may indicate a malfunction in the chain of data from measurement to storage, but may indicate a malfunction among the various devices involved in the demonstration project. Ranges and correlations can be monitored through near-contemporaneous analysis to catch changes in system configuration, for instance, that could throw calculations into disarray if undetected.

Step 19 Specify algorithms for calculation of impacts and impact metrics

The raw data from Smart Grid applications that must be processed into meaningful performance impacts and metrics can be daunting in volume and complexity. Algorithms are detailed plans for dealing with the elemental measurement data, combining it with other provided data and calculating impacts or impact metrics.

For example, formulas for some system performance metrics are well known, such as system reliability metrics SAIDI and MAIFI, which are defined in IEEE Standard 1366-2003. The implementation of either formula based on the data structured as generated by your project is an algorithm. Algorithms can be implemented in computer code automating calculation of performance metrics.

This step is placed after the determination of storage and retrieval protocols because the algorithms may depend on how the data are received from storage. However, algorithm development should begin with the specification of measurements and their periodicity. That is, the method of calculation should be laid out to decide what measurements and data are needed, then specified in minute detail as data structures are determined

6

ESTIMATING PROJECT IMPACTS, COSTS, AND BENEFITS

Scoping a Cost/Benefit Analysis

A CBA is usually an extrapolation into the future, a representation in monetary terms of a plan of actions and their impacts. It is not necessarily a representation of the experimental conditions as discussed above, or an evaluation of the costs and benefits of the experiment. Rather, it is an analysis *informed* by the results of experiments, cast to be representative of realistic implementation of a Smart Grid project beyond the demonstration framework. Scoping the CBA—determining what is to be included and what time frame it is to be analyzed in—is important for making sure that the proper physical observations are taken during the experimental demonstration phase.

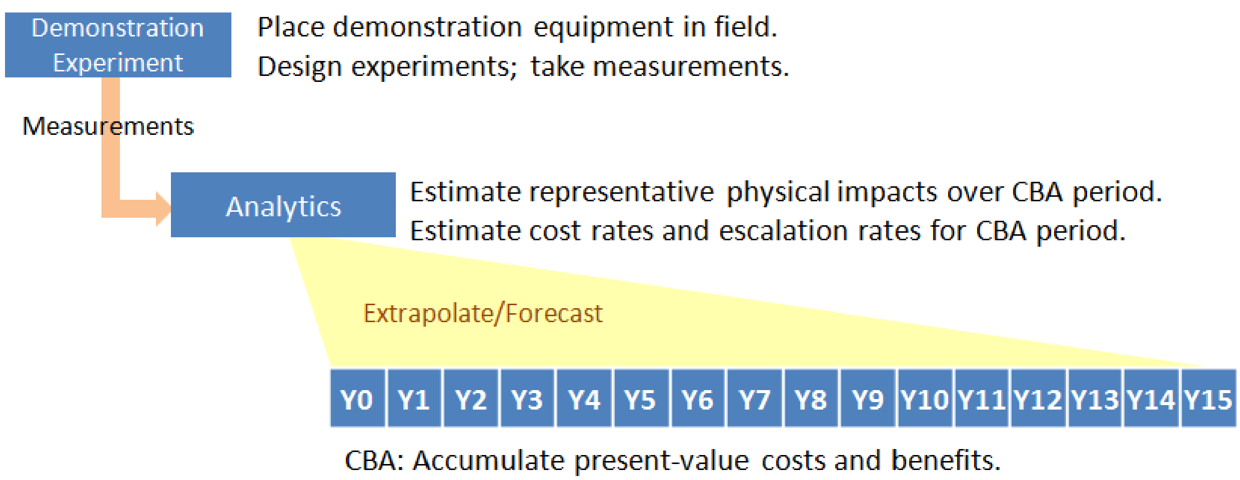

Figure 6-1
Extrapolation of Experimentally Determined Impacts to Period of CBA

What will be the time period of the CBA? Will impacts be stable across this time?

Estimating Project Impacts

In some cases project impacts may be measured directly, but as discussed above, in many cases the impact must be estimated, *even for the period of the experiment*, owing to the lack of a true baseline measurement. Further, often the true impact of interest is located well beyond the boundaries of the project, and estimation is the only tool. For instance, reductions in losses orenergy consumption are of economic interest because they save fuel and reduce emissions,[10]

[10] The Jevons, or rebound, effect supposes that efficiency gains are to some extent offset by additional consumption made economic by lower marginal costs. That is, if consumption is in equilibrium with cost, then consumption will increase if costs are reduced, eliminating some of the initial gains. If marginal costs of fuel and emissions were faced directly by consumers in consumption decisions, then these additional decisions to consume would ostensibly

both of which are physical impacts occurring potentially distant from the point of energy savings.

While various methods can be used to estimate impacts associated with the experimental conditions, a CBA for long-lived investments must include estimated costs and benefits extrapolated for many years into the future. The grounds for extrapolation of impacts must be examined, but frequently no science will be found on which to provide accuracy. In the best circumstances, experimental data can verify model results, which can provide a closer look at impacts that are difficult to measure, e.g., line losses. Models run using typical planning forecasted loads can be used to estimate impacts informed by the experimental results, with the proviso that planning estimates are subject to uncertainties as well.

Several classes of impact estimation can be identified from projects undertaken thus far. These methods each carry various uncertainties that can sometimes be characterized analytically.

- **Construction of a Counterfactual Model**

  Counterfactual model construction is aided by copious data collection during the experimental conditions. This method is perhaps best illustrated for estimating an improvement in interruption frequency and duration as a result of automated switching on a distribution system to restore service following a fault. The automated circuit is not experimentally faulted, but rather, naturally occurring faults are captured in data, for retrospective experiments to be run in a model of the original system. When a persistent fault occurs on the subject system, the interruption durations of individual customers or groups of customers are recorded, as usual. If customers have recording meters, then customers' consumptions following the interruption are also recorded. Importantly, the location of the fault and its time to clear are also recorded. The automated switching does not avoid a crew having to clear the fault, but it might reduce the number of crews sent to deal with a fault. This should be noted, along with the time to reach the faulted area.

  It may not be necessary to completely recreate an electrical model accurate down to the feeder loads in a model to determine how the crews would have dealt with the fault on the original system. The "model" in this case may be a by-hand reconstruction of how crews would have approached switching and service restoration given the configuration of switches and reclosers on the original system. Taking into account only the savings from automated switching, assuming typical times for coordinating manual switching as would have occurred for the fault. Section by section, customer durations for the counterfactual system are estimated. In this manner, any naturally occurring fault provides a case study of reducing outage durations.

- **Statistical/Regression Extraction**

  This refers mainly to the method of extracting impacts from Conservation Voltage Reduction (CVR) systems. Reducing voltage on distribution feeders reduces losses on the

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increase overall welfare, enabled by the increased efficiency. The value gained would be no greater than the savings originally estimated if the rebound were 100%, so economically we may be justified in ignoring the rebound completely. Lacking marginal-cost pricing, especially with regard to unpriced or undervalued emissions, the rebound effect would tend to deteriorate the economic value of efficiency gains. Nevertheless, we mention it only in passing, having no means to estimate or track it.

circuit, but to a greater degree reduces consumption within premises. The amount of feeder-load reduction (consumption plus losses) owing to voltage reduction is not directly measureable, and instantaneous response is not indicative of long-term response. The impact is small relative to the size of other natural variations in load from day to day and hour to hour.[11]

Generally, the methods used to evaluate the impact of voltage reduction involve regression analysis to estimate the sensitivity of load to voltage change over a period of time. The estimate is determined statistically using a regression model that takes into account weather variation and any other known factors that affect loads, such as holidays, day-of-week, and hour-of-day. Feeder load is measured over a period of time while alternating voltage between normal and reduced levels. The average load/voltage sensitivity over the period, which is small enough to not be visible graphically (except in the hour of switching), is derived from a regression coefficient. Naturally, any such estimate derived from regression is uncertain, and is affected by unaccounted-for events that occur during the measurement period.

- **Population Variance Analysis**

  Some projects involve estimating changes in customer behavior in response to price changes or event notifications of various types, including in-home displays. The analysis of customer behavior change can be treated using statistical hypothesis testing, where the behavior of one group of project customers is compared with another group for which there is no project, i.e., no price change or event notification. The control group, as a random sample of the population of customers, will exhibit natural and normal variation which will represent the variability of behaviors in the population. The treated group is also a random sampling from the population, which absent the project would be expected to behave much like the population. Measured behavior during events can then be compared with the control group behavior at the same time and evaluated as to the likelihood that the differences are chance variations.

Extrapolating Impacts Over the CBA Period

Converting physical impacts to monetary equivalents is potentially quite complex in almost every category, not least because both the physical impacts and their monetary equivalents must usually be projected over the life of the project for cost/benefit analysis, as depicted in Figure 6-1 above.

Extrapolating physical impacts poses the question of the trajectory of impacts over the life of the project. Is it stable, increasing, or decreasing? There may be little in direct evidence from experimental data to address the trajectory question, so logic and mechanisms should be employed to establish a basis for analysis. Some examples:

- Will reliability improvement be long lasting? This may be a question of growth on the feeders and/or the type of benefit assumed. In situations where reliability degrades

[11] As noted previously, the theoretical maximum real-power response from linear resistive loads is 2% reduction in consumption for each 1% of voltage reduction, but typical on-peak reduction on feeders is less than 1% reduction per 1% of voltage reduction. Practical levels of voltage reduction are typically less than 4%.

naturally over time, a reliability improvement from smart grid devices may simply defer other, more-expensive reliability upgrades that would have happened at some point in the future in any case. In such a case, a substantial benefit may be the asset deferral value, and the reliability improvement benefits may be declining during the period of deferral, and be less valuable after the ultimate upgrade occurs.

- Will the impact of Conservation Voltage Reduction be long lasting, or will it decline in time? This is not known, but we could find that loads sensitive to voltage may be declining in penetration. Electronic loads are becoming more efficient and are not generally voltage sensitive. Incandescent lighting is giving way to fluorescent and LED lighting, especially as quality and features are improved and their prices decline. While these are good things, they may reduce the impact of CVR over the period of time evaluated.

At the same time, there may be impacts that can logically be assumed to be relatively constant on some basis for the part of the system evaluated. Fault-location systems, for instance, may generally reduce the time required for crews to find faults, and there is no logic suggesting that this impact would degrade over time. In any case, a trajectory must be developed for any long-lasting impacts even if they are assumed constant, so the analyst should develop logic supporting these impact trajectories over time.

Extrapolating Cost Rates and Escalation Rates Over the CBA Period

The process of conversion of impacts to monetary equivalents is sometimes simplified to a relatively unhelpful expression that can be generalized as

Monetary equivalent = Cost/unit x (measured unit quantity – baseline unit quantity).

Aside from the inherent difficulties of obtaining clean baselines for measured quantities in smart grid demonstrations outside of laboratories, appropriate cost-per-unit figures are not often readily available, especially when considering that they must often be projected across the full period of analysis. That said, it is generally best to estimate and escalate cost or benefit rates over the study period apart from the physical quantities they are associated with. This avoids confusing the economic escalation reasoning with the physical extrapolation reasoning.

Per-unit rates of monetary equivalence should be expected to increase over time with inflation (a decrease in the buying power of a currency over time), and many analysts simply inflate such cost rates over time. However, a look at historical rates may show that costs for some quantities or commodities have not escalated in step with inflation, but may have escalated below inflation for some time. Prices for technology-based equipment or appliances often drops markedly as the products become mass produced; in addition, productivity of manufacture may improve at the same time as technological improvement.

For many commodities there are government-supplied forecasts of prices, in both inflated and real (non-inflated) terms. Comparing the two series of prices reveals at least one view of the expected price trajectory relative to inflation, but these same government sources also provide historical prices on a similar basis. Generation fossil fuels, for example, exhibit quite a bit of variation in price over time, but in general they have tended to decline in real terms between event-related price spikes or excursions, though sometimes a price trajectory will proceed from a new level following an event. Events, spikes, and excursions are not generally to be found in forecasts, even though forecasters may readily admit that they will occur. Such forecasts are often described as expected-value forecasts, with uncertainty ranges expanding across time. In any case, such government-supplied forecasts have the advantage of being based on a common economic scenario and inflation rate. If cost/price forecasts are obtained from multiple sources, then they may be based on disparate inflation scenarios. Price series based on different economic and inflation scenarios can be brought into rough equivalence if the inflation assumptions are known, with the proviso that the underlying economic assumptions that drive real escalations might be different in the two scenarios.

Cost and Benefit Categories for Cost/Benefit Analysis

Progressing toward a full cost/benefit analysis we are moving beyond the high-level benefits descriptions of the prior sections, toward a more elemental and explicit approach that analysts can use. In particular, additional emphasis should be placed on cost-causing factors, including not just construction and equipment requirements, but impact-related costs as well. Often an improvement in one facet comes at a cost in another facet, and the analysis should deal with such trade-offs explicitly. Further, a delineation of costs into capital and expense categories should be recognized, as well as a description of how each should be confronted in analytical terms.

The physical impacts that are interesting from a cost/benefit analysis perspective are those that cause economic benefits or costs. It may help to consider impacts in categories, organized according to the types of costs and benefits that they cause. We can identify several categories that encompass most impact-related costs and benefits

- **Reliability** (frequency and duration of customer interruptions)
- **Utility Operations** (people and how they do their jobs:
  non-fuel O&M, non-production assets, public and employee safety)
- **System Operations** (the power system and how efficiently it runs:
  losses, combustion, dispatch optimization, emissions)
- **Utility Assets** (production assets required in GT&D)
- **Power Quality** (harmonics, sags/swells, voltage violations)
- **Customer** (customer-borne costs, changes in service amount or value)

These categories are not all-inclusive, and users of the process may have others to include that are important in certain specific analyses. However, most impacts will affect the items in one of the groups. As we will see below, these areas section off the cost accounts of utilities in terms that are sufficiently broad to capture most kinds of cost changes that occur within a utility. Each of these can be broken down into details that may apply to a specific project. Further, the categories go beyond the utility cost accounts and into costs or benefits that are felt by customers and society in general. For instance, reliability improvement requires cost in the utility's accounts, but the improvement itself causes benefits on customers' accounts. Customers participating in certain programs may pay for devices entirely outside of the utility's accounting. Emissions impact society as a whole, and even though a utility may pay for emissions allowances, some analysts may want to consider the emissions costs that normally are not internalized by the electricity sector, and hence do not influence its operations.

The following discussion of impact monetization will be organized around these categories, which in some ways represent different domains of utility analysis. Grouping impacts within these categories will group impacts for which the monetization process should be very similar.

Reliability

The Reliability benefit category refers specifically to the frequency and duration of customer service interruptions. It does not refer to device, plant, or component reliability, which will be dealt with in other categories.[12] Nor does it refer to restoration cost, which will show up as a category of distribution cost in a different category.

Customer interruptions cause economic harm that varies with the type of customer, the duration of the interruption, and the time of the interruption in terms of season, day of week, and time of day. There are per-incident costs and per-hour costs. Some types of industrial customers are particularly sensitive to power interruptions, and many have backup generators to prevent their processes from being interrupted. At the other end of the spectrum, residential customers have much lower costs of interruptions, again depending on timing and duration. Utilities in some countries have taken steps to quantify these costs in the interest of determining how much reliability is worth to customers, and to plan for an optimal level of reliability. The values have been estimated by polling customers, and these surveys have taken place over many years in the U.S.

Utilities in many countries have used a figure to represent the economic harm that customers suffer if exposed to service interruptions. The figure is often termed the "Value of Lost Load" or VOLL. The VOLL was historically used to represent the cost of interruptions at times of peak demand, when resources are most scarce. VOLL was generally a large number, in the range of thousands of US dollars per megawatt-hour. While this figure is appropriate for estimates of capacity values at peak times, it is not generally proper for use at the distribution level, where interruptions occur with random frequency over various times of day and year.

In a U.S. DOE-funded study,[13] the results of 28 surveys done by 10 utilities in the U.S. were combined to create customer damage functions relating the cost of interruption to customer type, duration, time of year and time of day. By being specific to customer type and time of interruption, these functions are most applicable at the distribution level, where residential and commercial loads dominate and they can be separately counted. The effort produced a model called the Interruption Cost Estimate (ICE) Calculator. The calculator provides an estimate of interruption costs based on the distribution of customers among various commercial, industrial, and residential classifications. While the underlying customer damage functions do not vary

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[12] This category, after all, is intended to encircle the customer cost of interruptions and to separate it from other mechanisms of cost causation. Component reliability is related to customer interruptions, of course, but the cost of reducing or maintaining interruption frequency through redundant components is a matter of asset and/or operations costs, which appear in another category. Any project may have costs in one category and impacts in another.

[13] Michael Sullivan, Matthew Mercurio, Josh Schellenberg, *Estimated Value of Service Reliability for Electric Utility Customers in the United States*, prepared for the U.S. Department of Energy, Washington, DC, Contract No. DE-AC02-05CH11231 (2009).

from state to state, the calculator does supply census data by state, which populates the input fields with statewide values.

Accurate measurements of interruption events must be recorded so that reliability improvement can be demonstrated. However, demonstrating reliability improvement presents a major difficulty. Generally, utilities must wait for faults to occur naturally in order to see how an application performs. As is often the case in smart grid, once an application is installed, the performance of the pre-application system is unavailable for direct observation. Simulating the response of the pre-application system to the faults observed during the demonstration can provide a subjective comparison, assuming no change in performance by field crews. Alternatively, the response of the new system could be simulated with the historical faults. In either case, one or the other of the scenarios is subjective. Nevertheless, the simulation method of comparing the old versus the new system for the same period of time may be a better way than comparing different periods of time, as historical performance may be highly variable.

The IceCalculator provides estimates of customer costs from sustained interruptions of duration 8 hours or less. It does not provide a cost of momentary interruptions, nor does it estimate the cost of long-term interruptions such as might be experienced in a major event such as a strong damage-causing storm.

Table 6-1
Reliability Cost and/or Benefit Quantities

Reliability	Interruption Costs, Sustained	Δ Customer costs, from damage functions
	Interruption Costs, Momentary	Δ Customer costs, from damage functions
	Interruption Costs Major Event	Δ Economic loss estimate, apart from utility cost
	Interruption Costs, Other	Δ Other categories of customer cost, as appropriate

Table 6-1 provides a short list of the major interruption-cost quantities. The first quantity is the type addressed specifically by the IceCalculator, i.e., sustained interruptions such as are incurred in the most common types of faults.

Utility Operations

This category of costs and benefits refers to how a utility does its job with people, tools, and buildings. Many Smart Grid applications put new tools in the hands of operators, planners, and workers in the field, changing the way they work, the time it takes to get their jobs done, and the cost of their time and materials. In some cases the main benefit of a project will be reduced operations cost, where investments are made in advanced applications for Distribution Management Systems (DMS), for instance. Other projects, such as Distribution Automation, may have profound impacts on reliability, but also reduce the cost of service restoration as well. In any case, for any given project, this category should capture any changes in staffing, office space, or office tools and equipment that may be related to the project, as well as any ongoing maintenance or support requirements.

Distribution Automation, for instance, has been shown to reduce the labor and truck rolls required to make repairs and restore service to interrupted customers, reducing utility cost in addition to reducing the customers' cost of interruptions. Though it is tempting to reach directly for cost changes for use in CBA analysis, operational changes should be estimated in physical terms. Truck rolls and restoration labor hours are affected by improving fault location, for example. Ideally, physical changes such as these can be analyzed to determine how they have changed on average, so that they can be cast in an expected-experience year for extrapolation of impacts into the future.

For example, a particular circuit may exhibit 20 weather-related faults per year on average, but it may experience 10 or 30 during the test period. Either number may be well within the historical distribution of such faults. Distribution automation will not change the number of weather-related faults,[14] but it will likely reduce the labor and truck rolls required for each one. The test-period experience should be used to estimate the reduction in physical requirements per fault, then extrapolated into the future for the historical average number of faults per year, 20 in the example.

Smart Grid investments in the control center and in the field bring requirements for operating and maintenance costs in addition to the revenue requirements associated with the distribution equipment and control-center investments. Again, in preparation for the CBA, the physical demands of the project – labor and machines – should be estimated for extrapolation into the future. Tools and machines may need replacing within the period of the CBA.

On a utility's accounts, the cost of utility operations are found mainly under non-fuel operating and maintenance expense categories, as shown in Table 6-2. Where applicable, these are categorized into generation, transmission, distribution, administrative & general (A&G), and customer-related functions. The distribution expenses include maintenance and repair of the power system, while the customer functions handle customer accounts, meter reading, billing, and other customer interactions. Most of the cost of utility operations is expensed, that is, amounts that are charged against net income in the current period and are generally assumed to be charged to customers in the current period.

There are, however, assets that support utility operations: trucks, tools, buildings, control rooms, software, computers, etc. These items are not generally expensed in their entirety in the period when they are purchased. Rather, they are expensed to customers over the life of the assets through the periodic depreciation allowance. Also during the life of the assets, customers pay the carrying cost of the remaining undepreciated balance, as well as any property taxes. Some assets in this category have relatively short lives, however, so some analysts may want to treat these assets as expenses for CBA purposes. Regulator and entity conventions should be followed.

[14] This may understate the impacts. It is true that reclosers and automatic switching logic will not affect how many trees are blown into power lines by storms. However, the greater visibility of the system conditions through additional sensors and sensing equipment coupled with data analytics will provide information that may alert utilities to problem areas before they develop into causing sustained interruptions.

Table 6-2
Utility Operations Cost Categories

Utility Operations	Non-Fuel O&M (Operating and Maintenance)	G	Δ O&M expenses by function
		T	Δ O&M expenses by function
		D	Δ O&M expenses by function
		Customer	Δ O&M, including meter reading expenses
		Admin & General	Δ Building-related O&M expenses
	Non-Prod Assets	Trucks, A&G, Tools	Δ revreqs Includes control rooms, software, computers, etc.

Though this table and the others that follow appear to be in terms of monetary quantities, the Cost/Benefit Analysis will have physical quantities behind it, extrapolated into the future to the extent practical. Rates of cost per physical unit can be escalated separately according to economic factors and applied to the physical quantities as they occur across the period of the analysis. So, while the final summary of utility operations costs might appear as in the figure, physical details, cost rates, and itemized details underlie each active cost category. Naturally, individual projects may cause activity in only one or two of the categories here, and some of the categories such as G & T may not apply at all to distribution-only utilities.

System Operations

The System Operations category deals with changes in the operation of the power system itself, i.e., the generators, wires and transformers that produce electric energy and deliver it to consumers. Technologies that reduce energy losses of various types on the power system will have an impact on system operations. The benefits of loss reduction or energy conservation appear as reduction of fuel use and emissions, but reduction of peak losses provide some capacity benefits as well, benefits that actually appear in the Utility Assets category. The System Operations category, however, includes only expense items associated with energy production and delivery. A list of operation expenses might include any of the following:

Table 6-3
System Operations Costs

System Operations	Fuel	Δ Fuel expense (for generating companies)
	Purchased Power	Δ Purchased Power (esp for non-gen retailer)
	Ancillary Services	Δ A/S (mainly in ISO/RTO markets)
	Emissions - SO_2, NOx, CO_2	Δ for allowances (for generating companies)
	Operator Costs	Δ ISO/RTO operator costs
	Revenue on Enabled Sales	Δ for enabled sales, under some conditions

This varied list of operating costs raises issues of utility structure – not all utilities participate in system operations. Nevertheless, this category is important in CBA for accounting for the value of energy savings regardless of a utility's structure. After all, the CBA is not a financial analysis of any particular utility, but is rather an accounting of the costs faced by consumers in the group represented by the CBA. Many fully integrated utilities have pass-through of operations expenses, such that a direct link between customer purchases and fuel expense can be imagined. In bid-based market systems, especially where retail access is allowed, the link between cost and what customers pay is blurred significantly. In the spirit of societal cost/benefit analysis, analysts can estimate the marginal cost of energy in the relevant market for evaluating load or loss changes, as if such savings flow directly to consumers.

The table is a combination of cost categories which might be viewed by several different types of companies. A wires-only distribution company may not participate at all in the customers' energy purchase decisions, and may not even know how much its customers are paying for energy. An integrated utility may have fuel and emissions allowance costs, but may not have identifiable ancillary services costs or operator costs. Its operations expenses are O&M expenses. A distributor/retailer may not burn fuel or pay emissions allowances, but may purchase power, ancillary services, and operator services. A distribution wires company, on the other hand, doesn't burn fuel and may not even purchase power, so on its books it may have none of these expenses. However, this serves to emphasize that the cost/benefit analysis methodology is from a customer/societal point of view, not that of an individual utility. If a distribution wires company reduces losses, there is a reduction in fuel expense and emissions on the power system, and those are legitimate benefits. The financial/ratemaking situation of the individual utility is an important but separate matter.

System models and load flow analysis tools may be the best tools for evaluating the impacts of applications that reduce line losses. Furthermore, the value of loss reductions is locational. It is most valuable in importing regions with high-cost resources, areas where locational prices are high. Improving losses in areas with abundant low-cost resources may be noble, but low price of power means that the economic value is less in those locations. Emissions are similar, but since all emissions are not priced directly, they are not equally reflected in locational prices for power.

The key for analyzing impacts that affect the larger power system is that they be determined at the margin, not at the average. Hydro energy tends to be used fully regardless of small changes in load, so the devices that reduce losses won't avoid hydro energy. The same goes for nuclear energy, which is rarely drawn down from maximum available output, and most renewable resources, which are generally non-dispatchable and rarely curtailed. Consequently, hydro, nuclear, and renewable costs do not belong in the avoided cost of losses or the estimation of emissions reductions. Almost everywhere, marginal reductions in energy result in marginal reductions in coal and gas consumption, even though the ultimate reduction may occur far from the site of the change and within an entirely different utility.

Estimates of system marginal costs and emission rates can be developed from wide area system models, or various levels of estimation may be employed. For instance, a proxy unit can be used as a first approximation, say, a typical combined-cycle gas unit's heat rate and emissions rates. The cost may be based on a gas-price forecast, and may be adjusted for typical losses from the generation to the distribution level, or a shaped implied heat rate may be determined from daily gas prices and hourly electricity prices in the relevant market and then applied forward with a gas-price forecast.

Utility Asset Costs/Capital Revenue Requirements

The Utility Asset category accounts for the assets required to do the utility's main job of generating, transmitting, and/or delivering power. Utilities are always investing in and consuming assets. If utilities are able to provide the same reliable service with fewer or less expensive assets, then utilities are able to provide service at lower cost to consumers. A variety of impacts may contribute to a deferral or elimination of capital requirements. Reduction of peak losses or peak demand, for instance, vacate capacity in generators, lines, and transformers, such that upgrades or capacity additions may be deferred or eliminated. Similarly, reliability improvements brought about by distribution automation may allow deferral of upgrades or substation additions that would otherwise have been needed to support reliability.

Conventional utility planning analysis generally assumes a customer point of view, approaching utility costs as they are presented to consumers. Expenses, such as described in the prior categories, generally flow to consumers in the current period, by assumption if not in fact. Construction expenditures, on the other hand, are not charged to consumers directly, but rather are booked as long-lived assets that are charged to consumers over the life of the asset, along with taxes and financial carrying costs. Utilities normally have revenue requirement models or calculators that can project, for a specific asset, a stream of capital-related revenue requirements over the depreciation life of an asset. The revenue requirements are composed of interest, taxes (income and property), and "return of and on" invested capital, in the form of depreciation and net income, as appropriate for the particular type of entity consistent with its ratemaking arrangements. These revenue requirements estimate how utility assets appear to customers as costs. When capital is deferred, the entire stream of revenue requirements shifts into the future, and it may grow in nominal terms if the cost of equipment and labor increases during the deferral period. The value of deferral in present-value terms is the present value difference between these long-term revenue requirement streams.

Capital-related revenue requirements for electric utilities may be categorized as Generation, Transmission, Distribution, or Administrative/General (A&G). The A&G category includes buildings, but such capital devoted to the distribution business, for instance, may appear in the Distribution category of the business. We included these capital revenue requirements in the Utility Operations category of costs, however, since they support utility operations. The categories depicted in the table below refer to the assets of the system itself, which will be separated from the operational assets on most utility's accounts.

Table 6-4
Categories of Capital Revenue Requirements

Capital Revenue Requirements	Capital Deferral/ Advancement	G	Δ revenue requirements, including taxes and net income
		T	Δ revenue requirements, including taxes and net income
		D	Δ revenue requirements, including taxes and net income

Accounting properly for the value of a deferral of a long-lived asset must be done carefully. As an example, consider deferring a substation for five years in the middle of a 10-year study period. While the analyst can calculate the annual revenue requirement differences between the two in-service dates, note that the differences in revenue requirements extend well beyond the end of the study period, even if the scenarios converge to a common path. Savings during the period of deferral are reversed and partly erased after the deferred asset goes commercial on its later in-service date. The present value of revenue requirement differences will show net savings from deferral, as long as cost escalation during deferral is less than the discount rate.

This serves merely to introduce the idea of proper termination of cost/benefit analysis. It is generally not valid to track costs and benefits for a limited period of time unless everything is common at the end of that time. For example, a 10-year study that includes decisions on 30-year assets requires some accounting for the 20 years of valuable assets remaining at the end of the ten years. It may not be necessary to run the study for 30 years to capture the value, but some means of accounting for it may be necessary, keeping in mind that the point of view of the termination logic is still customer or society.

Customer Costs/Benefits

This category deals explicitly with non-reliability costs or benefits outside of the utility cost function. This is not intended to be a component of a participant or non-participant test; the CBA described here is concerned with total costs and total benefits. That is, it reflects a total resource cost view or a societal view. Consequently changes in a customer's bill are not a component of the analysis; such changes are reflected in the changes in the utility cost function. Rather, this category recognizes costs such as equipment purchases (e.g., in-home displays and/or programmable thermostats) or changes in service value. The use of this latter category would be rare, but it is included as a reminder that any change in electric service that is not decided by the customer themselves in response to incentives might represent a loss of value for the customer. As an unlikely example, if customers were involuntarily required to curtail air conditioning use on the hottest of days, then customers would suffer a cost. In absence of the curtailment, they would have consumed, paid for the service, and received value. If, on the other hand, a customer voluntarily accepts payment in return for allowing the utility to curtail, then we can assume that the payment is sufficient compensation to cover the loss of value.

Table 6-5
Account of Other Customer Costs

Customer	Value of Service (Comfort, Light, etc)	∆ Value at least as great as otherwise would have paid for it
	Cost of equipment (Devices)	∆ Cost of program-related devices

Other: Theft Reduction

Better detection of theft is often cited as a benefit of smart meters. Theft is a non-technical loss of energy that paying customers are paying for. Interestingly, looking at theft reduction only in terms of total revenue requirements can lead to a conclusion that theft doesn't matter. That is, aside from the fairness issues, theft doesn't change total revenue requirements, and correcting theft only redistributes cost responsibility among the group of customers. However, paying customers can be considered to be paying for the theft, losing value.

There are at least two outcomes from resolving theft: The consumer remains and pays for power, perhaps at a reduced rate of consumption, or the consumer leaves the service territory and doesn't consume at all. To include these possibilities on behalf of paying customers, if the customer continues consuming the same amount of energy and now pays for it, the retail value may be considered as a benefit to paying customers, disregarding the fact that the erstwhile non-paying customer is losing the same amount. If, however, the consumer reduces consumption, other customers are relieved of the cost of that energy, incurred at marginal cost.

Summary of Economic (Monetized) and Informational Cost Changes

The table in Table 6-6 summarizes the various cost categories discussed above, casting them in the form of a cost/benefit analysis summary, including both quantitative and qualitative categories of information. This table is a tally of *cost differences* between two alternatives. Some differences will be positive, impact-related *costs* or implementation costs and some will be negative. This table, then, takes the form of a cost/benefit analysis.

This is only a suggested format, and many more types of information can be added. However, the economic portion of the table is intended to include categories that cover most electric utility costs. Detailed line items can be broken out of the general categories if necessary, but most should fit into one of the categories. In a practical cost/benefit analysis of a smart grid project, not all rows of such a table would be active, and each active row would have more detailed calculations behind it. Changes in distribution O&M expenses, for instance, might cover changes in restoration costs and other changes in the distribution division of a utility, and in a study of devices that improve speed of fault location, this might be important to break out. However, this is distinct from the value of reliability improvement, which may not show up on the utility's expense statements at all, but rather, is an economic value that accrues to customers who obtain better reliability.

The economic costs and benefits section of the table could be filled in entirely with monetary values, but only the top three subsections are changes that occur within the utility cost function: System Operations, Utility Operations, and Capital Revenue Requirements. System and Utility Operations are almost completely composed of expenses, that is, costs that are assumed to be recovered in the year they occur. That is, an expense is part of the annual revenue requirement. Capital Revenue Requirements, on the other hand, are annual amounts associated with return of and on invested capital, including taxes and any time-shifting effects of various tax policies, such as accelerated depreciation for income tax purposes. The Utility Operations category includes a non-production assets category (composed of relatively short-lived assets such as trucks, computers, tools, etc.), present because it is an integral part of operations, but that may be subject to revenue requirement treatment.

With all utility changes accounted for, the sum of the three utility-cost sections should reflect the change in utility revenue requirements resulting from, for instance, a smart grid investment and its various impacts on how the utility operates. However, the economic analysis suggested here is agnostic about whether or when the changes are reflected in a utility's rates or revenues, assuming essentially that revenue equals revenue requirement, as is common in utility planning analysis. A utility's financial analysis of its cost-recovery issues is important, but is not treated here as a part of a broader economic analysis. Below the utility-cost sections, additional economic categories are included that reflect customer-cost changes, including the value of any reliability or level-of-service changes that customers would experience, expressed in monetary terms. Direct customer costs are included here as well.

Savings from theft reduction are included as an "other" category. This is an unusual category of benefit, as discussed above. It may not be reflected as a change in utility cost but may increase revenues, which would be credited against other costs in this "revenue = requirement" type of analysis.

Table 6-6
Cost/Benefit Analysis Summary Table

				Δ Present Value	Year 1	Year 2	…	Year n
Economic Costs and Benefits	System Operations		Fuel					
			Purchased Power					
			Ancillary Services					
			Emissions - SO_2, NOx, CO_2					
			Operator Costs					
			Revenue on Enabled Sales					
	Utility Operations	Non-Fuel O&M (Operating and Maintenance)	G					
			T					
			D					
			Customer					
			Admin & General					
		Non-Prod Assets	Trucks, A&G, Tools					
	Capital Revenue Requirements	Capital Deferral/ Advancement	G					
			T					
			D					
	Reliability		Interruption Costs, Sustained					
			Interruption Costs, Momentary					
			Interruption Costs Major Event					
			Interruption Costs, Other					
	Customer		Value of Service (Comfort, Light, etc)					
			Cost of equipment (Devices)					
	Other		Savings from Theft Reduction					
	Environment		ΔTons SO_2					
			ΔTons NOx					
			ΔTons CO_2					
			ΔPounds Hg					
			ΔParticulates					
Security Impacts			Oil Saved					
			Major Blackouts Avoided					
Power Quality Impacts			Change in Momentary Outages					
			Change in Sags, Swells, Voltage violations	n/a				
Efficiency Impacts			ΔkWh System Losses	n/a				
			ΔkW System Losses	n/a				
			ΔkWh Consumed	n/a				
			ΔkW Consumed	n/a				
Metering Impact			Metering Accuracy					
Safety Impact			Public Safety					
			Employee Safety					

The table suggests a summary sheet for a cost/benefit analysis, containing change-in-cost data for economic quantities and other quantitative and qualitative information.

Emissions costs are included as System Operations expenses, reflecting that utilities burning fuel may have to purchase allowances for various types of emissions or pay taxes accordingly. In other words, some emissions result directly in operating expenses. However, the emissions are included again as a separate category below the utility-cost section, where analysts may want to include changes in physical emissions quantities, and may want to include a societal cost for emissions in excess of any expenses paid by the utility.

The items below Economic Costs and Benefits are items that would not be included in the monetary analysis, but may be used for scoring of qualitative characteristics of a project. Any items that can be monetized should be moved into the Economic category and included there. For example, a project intended to solve a power-quality problem may focus on reduced damage of customer equipment, which would allow putting a monetary value on power-quality improvement.

Table 6-7
Benefits Table from Methodological Approach Related to Cost/Benefit Categories

Benefits - "Methodological Approach"			Primary Benefit Category
Economic	Improved Asset Utilization	Optimized Generator Operation	System Operational Efficiency
		Deferred Generation Capacity Investments	Utility Asset Efficiency
		Reduced Ancillary Service Cost	System Operational Efficiency
		Reduced Congestion Cost	System Operational Efficiency
	T&D Capital Savings	Deferred Transmission Capacity Investments	Utility Asset Efficiency
		Deferred Distribution Capacity Investments	Utility Asset Efficiency
		Reduced Equipment Failures	Utility Asset Efficiency
	T&D O&M Savings	Reduced Distribution Equipment Maintenance Cost	Utility Operational Efficiency
		Reduced Distribution Operations Cost	Utility Operational Efficiency
		Reduced Meter Reading Cost	Utility Operational Efficiency
	Theft Reduction	Reduced Electricity Theft	Utility Operational Efficiency
	Energy Efficiency	Reduced Electricity Losses	System Operational Efficiency
	Electricity Cost Savings	Reduced Electricity Cost	Customer Efficiency
Reliability	Power Interruptions	Reduced Sustained Outages	Reliability
		Reduced Major Outages	Reliability
		Reduced Restoration Cost	Utility Operational Efficiency
	Power Quality	Reduced Momentary Outages	Power Quality
		Reduced Sags and Swells	Power Quality
Environmental	Air Emissions	Reduced CO_2 Emissions	System Operational Efficiency
		Reduced SOx, NOx and PM-10 Emissions	System Operational Efficiency
Security	Energy Security	Reduced Oil Usage (not monetized)	System Operational Efficiency
		Reduced Wide scale Blackouts	Reliability

Linkage of Benefit Categories to Benefit Tables in the Methodological Approach

Table 6-7 provides a list of the original Smart Grid benefits from the Methodological Approach, along with the Benefit Categories that best correspond to them. The list of benefits in the Methodological Approach is excellent for discussing or showing how a smart grid technology provides benefits because it categorizes benefits in commonly used high-level terms that people such as regulators and policy makers hear about. It concentrates on benefits, characterizing most rows in words that suggest a positive benefit, e.g., *reduced* losses or *deferred* investment. Though the benefit areas are described individually in the Methodological Approach, analysts may yet find it easier to work in more elemental and concrete utility-cost terms familiar to utility analysts, then later rolling up or allocating total benefits among the various high-level categories, if necessary.

Finally, Table 6-8 cross-references the cost and impacts table with the original benefits table. This serves to illustrate the complexity of some of the original benefits, as well as how some of them overlap in the same cost categories. Experience working with these cost categories in cost/benefit analysis will provide methods for translating cost differences into the original set of benefits, though some of these methods will be suggested by the specifics of monetizing benefits from physical impacts.

Step 20 Estimate physical impacts from measurement data.

Measurements must be taken according to the plans and protocols established in the research plan. The algorithms in the research plan should have anticipated any data or analytical needs so that the experiment al period produces the data necessary. However, it is common for issues to arise during data collection. Perhaps many devices and communications links must all be working simultaneously for data to ultimately be recorded successfully in its proper place and format. The analyst should develop sufficient data to establish an estimate of the impacts for the period of the experiment.

Step 21 Convert physical impacts to monetary values

Convert physical impacts to monetary values using selected methods. Rates of monetary conversion must be escalated for the period of the study, using appropriate logic for escalations greater or less than general inflation. The general inflation assumption should be the same for all monetary conversion rates in the study.

Table 6-8
Benefits from Methodological Approach Related to CBA Line Items

Costs and Impacts for CBA			Economic													Reliability					Environmental		Security	
Methdology Approach Benefits →			Improved Asset Utilization				T&D Capital Savings			T&D O&M Savings			Theft Reduction	Energy Efficiency	Electricity Cost Savings	Power Interruptions			Power Quality		Air Emissions		Energy Security	
			Optimized Generator Operation	Deferred Generation Capacity Investments	Reduced Ancillary Service Cost	Reduced Congestion Cost	Deferred Transmission Capacity Investments	Deferred Distribution Capacity Investments	Reduced Equipment Failures	Reduced Distribution Equipment Maintenance Cost	Reduced Distribution Operations Cost	Reduced Meter Reading Cost	Reduced Electricity Theft	Reduced Electricity Losses	Reduced Electricity Cost	Reduced Sustained Outages	Reduced Major Outages	Reduced Restoration Cost	Reduced Momentary Outages	Reduced Sags and Swells	Reduced CO_2 Emissions	Reduced SO_x, NO_x and PM-10 Emissions	Reduced Oil Usage (not monetized)	Reduced Wide scale Blackouts
Economic Costs and Benefits	System Operations	Fuel	●	●		●	●							●	●									
		Purchased Power	●	●		●	●							●	●									
		A/S	●	●	●									●	●									
		Emissions - SO2, NOx, CO2	●	●		●	●							●	●									
		Operator Costs																						
		Revenue on Enabled Sales	●	●		●	●							●	●									
	Utility Operations	Non-Fuel O&M: G	●	●			●		●					●	●									
		Non-Fuel O&M: T					●		●						●									
		Non-Fuel O&M: D						●	●	●	●				●			●						
		Non-Fuel O&M: Customer										●												
		Non-Fuel O&M: A&G										●												
		Non-Prod Assets: Trucks, A&G, Tools																						
	Capital Revenue Requirements	Capital Deferral/ Advancement: G		●					●						●									
		Capital Deferral/ Advancement: T					●		●						●									
		Capital Deferral/ Advancement: D						●	●						●									
	Reliability	Interruption Costs Sustained/Normal							●							●								
		Interruption Costs Momentary																	●					
		Interruption Costs Major Event															●							
	Customer Efficiency	Value of Service (Comfort, Light, etc)													●									
		Cost of equipment (Devices)													●									
	Equity	Theft Reduction											●											
	Environment	ΔTons SO2	●											●	●							●		
		ΔTons NOx	●											●	●							●		
		ΔTons CO2	●											●	●						●			
		ΔPounds Hg	●											●	●									
		ΔParticulates	●											●	●							●		
Security Impacts		Oil Saved	●																				●	
		Major Blackouts Avoided																						●
Power Quality Impacts		Change in Momentary Outages																	●					
		Change in Sags, Swells, Voltage violations																		●				
Efficiency Impacts		ΔkWh System Losses												●										
		ΔkW System Losses												●										
		ΔkWh Consumed													●									
		ΔkW Consumed													●									
Equity Impact		Metering Accuracy																						
Safety Impact		Public Safety																						
		Employee Safety																						

7 NEXT STEPS

At this point of the process we have placed prototype or early versions of innovative equipment in the field, and perhaps both the utility and the equipment vendors have learned lessons in the process. We have experimented with the new systems in the field, and taken measurements with which we have estimated impacts, i.e., all physical changes in system behaviors that may have economic benefits or costs. But while the costs of outfitting the system and placing it in the field is known, the demonstration or pilot scenario is not quite the proper one for analysis. That is, it is not of primary importance whether demonstration or pilot projects are economic; in fact, we may as well assume they are not.

The cost of newly developed products is high, especially if custom-made or prototyped. After the new products are proven and begin to be manufactured in bulk, their prices will inevitably drop. Further, a utility installing unfamiliar systems, unlike any of its existing systems, will take more time and caution, perhaps performing laboratory testing before field trials, and perhaps experimenting with different configurations and control schemes in the field. The pilot project is a time of experimentation, not just to establish impacts, but also to figure out how best to place the systems in operation and make them work.

Further, the scope of implementation in a demonstration is limited to that of the demonstration system, which likely does not represent the variety of situations to be encountered in systemwide deployment. For example, if we learn, in the pilot, how to outfit a few feeders, have we learned enough to know how to outfit most or all of the feeders in the service territory? If we have learned that much, then the pilot system may be just one of many configurations that should be evaluated.

In short, the costs and deployment times for a pilot project are not representative of the placement of the technologies as they will occur in routine production mode. And the pilot system may not be fully representative of the systems for which we intend to apply the question of economic benefits. We may want to know whether full deployment over a utility's entire system is economic. Alternatively, we may want to know whether there are certain characteristics of feeders, for instance, that can render a technology ineffective and too expensive. Under what conditions should the technology be applied? Under what conditions should it not?

The remaining steps of the CBA process for demonstration projects take the results from the demonstration projects and use them to project into multiple scenarios based on expected future deployment costs and the variety of situations that a utility may encounter in its deployment plans. These issues are left to future editions of this report.

A

ABBREVIATIONS AND DEFINITIONS

Abbreviations

ADITx: Accumulated Deferred Income Tax

AMI: Advanced Metering Infrastructure

CBA: Cost Benefit Analysis

CVR: Conservation Voltage Reduction

DOE: United States Department of Energy

DER: Distributed Energy Resources

EMS: Energy Management System

EPRI: Electric Power Research Institute

FACTS: Flexible Alternating Current Transmission Systems

HTS: High-Temperature Superconductor

O&M: Operations and Maintenance

RTU: Remote Terminal Unit

RTO: Regional Transmission Organization

ISO: Independent System Operator

IOU: Investor-owned Utility

TSO: Transmission System Operator

DSO: Distribution System Operator

SG: Smart Grid

Var: Volt-Ampere Reactive

VLI: Very Low Impedance

VVC: Volt/Var Control

VVO: Volt/Var Optimization

Definitions

Application: A description of how and where a technology or system will be applied, including its location, type of connection, direction of influence, its point of impact, its intended use, and its market/system environment.

Asset: The term often refers to any device, system, machine, building, or property that is durable and useful for longer than a year. This is linked to the accounting definition of Assets, which are the monetary equivalent of such properties on the balance sheet of a firm or government.

Baseline Quantity: A measurement or estimate of a quantity that is consistent with the Baseline Scenario

Baseline Scenario: A counterfactual scenario or data series corresponding to what would have happened, but for the project.

Benefit: A benefit is an economic quantity, ideally a monetized value associated with a physical impact. The distinction between the economic quantity and its physical impact is intended to expose and highlight the important process step of monetization that must occur prior to cost/benefit analysis. Difficult-to-monetize or difficult-to-quantify impacts may be referred to as benefits, which may be included in a qualitative scoring portion of a cost/benefit analysis.

Expense: In the utility accounting sense, a monetary expenditure assumed to be recovered in the current period, i.e., not capitalized for later recovery. Is reflected in an expense category on the entity's income statement.

Function: A device or system's functions are its physical capabilities. All functions of a system may not be employed in every application of the system.

Hypothesis: A provisional statement that must be tested experimentally to determine if it is likely true.

Impact: An impact is a physical *change* caused by the action of a system or device. As a change, it is a comparison of the changed quantity and its corresponding baseline quantity.

Goals: A long-term, general description of what is to be achieved

Metrics: Metrics are calculated quantities used to characterize the performance of a system or organization. Metrics may correspond to physical quantities that are directly measureable, but more often they are calculated from measurable quantities. An example of a metric is SAIDI, the System Average Interruption Duration Index, used with other such indices to characterize the reliability of a power system. It cannot be measured directly, but it is calculated from measured interruption durations and counts of customers on the system.

Objectives: Associated with a specific goal, but includes a short-term tangible action that can be measured

Revenue Requirement: The amount of revenue required during a period to cover all expenses, including non-cash expenses such as depreciation, and provide a return on non-depreciated equity investment, in the case of investor-owned utilities.

System: A combination of devices and software acting and interacting together, assembled to produce certain functions, which may be very broad and flexible. Devices are likely systems as well, composed of smaller sub-systems.

Technology: Often used interchangeably with System or Device, but may also refer to bodies of accumulated applied knowledge surrounding various classes of systems or devices.

Var: The var (volt-ampere reactive) is a frequency-domain quantity describing a component of power flow that alternates symmetrically at 2 times the fundamental frequency of the AC power system. Vars are associated with the component of alternating current that is 90° out of phase with the voltage fundamental, signifying a portion of total current that carries no net energy between source and load, yet causes losses and exacerbates voltage drop.

B
SMART GRID FUNCTIONS

Table B-1
Definition of Smart Grid Functions and Types of Technologies[15]

Function	Definition and Types of Technologies
Transmission Level	
Flow Control	Flow control requires techniques that are applied at transmission and distribution levels to influence the path that power (real & reactive) travels. This uses such tools as flexible AC transmission systems (FACTS), phase angle regulating transformers (PARs), series capacitors, and very low impedance superconductors.
Wide Area Monitoring and Visualization	Wide area monitoring and visualization requires time synchronized sensors, communications, and information processing that allow the condition of the bulk power system to be observed and understood in real-time so that action can be taken.
Distribution Level	
Adaptive Protection	Adaptive protection uses adjustable protective relay settings (e.g., current, voltage, feeders, and equipment) in real time based on signals from local sensors or a central control system. This is particularly useful for feeder transfers and two-way power flow issues associated with high DER penetration.
Automated Feeder Switching	Automated feeder switching is realized through automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. These devices can operate autonomously in response to local events or in response to signals from a central control system.
Automated Islanding and Reconnection	Automated islanding and reconnection is achieved by automated separation and subsequent reconnection (autonomous synchronization) of an independently operated portion of the T&D system (i.e., microgrid) from the interconnected electric grid. A microgrid is an integrated energy system consisting of interconnected loads and distributed energy resources which, as an integrated system, can operate in parallel with the grid or as an island.

[15] *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects.* EPRI, Palo Alto, CA: 2010. 1020342 (p. 4-6 – 4-7).

Table B-1 (continued)

Automated Voltage and VAR Control	Automated voltage and VAR control requires coordinated operation of reactive power resources such as capacitor banks, voltage regulators, transformer load-tap changers, and distributed generation (DG) with sensors, controls, and communications systems. These devices could operate autonomously in response to local events or in response to signals from a central control system.
Enhanced Fault Protection	Enhanced fault protection requires higher precision and greater discrimination of fault location and type with coordinated measurement among multiple devices. For distribution applications, these systems will detect and isolate faults without full-power re-closing, reducing the frequency of through-fault currents. Using high resolution sensors and fault signatures, these systems can better detect high impedance faults. For transmission applications, these systems will employ high speed communications between multiple elements (e.g., stations) to protect entire regions, rather than just single elements. They will also use the latest digital techniques to advance beyond conventional impedance relaying of transmission lines.
Real-time Load Transfer	Real-time load transfer is achieved through real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system performance.
Substation Level	
Diagnosis & Notification of Equipment Condition	Diagnosis and notification of equipment condition is defined as on-line monitoring and analysis of equipment, its performance and operating environment to detect abnormal conditions (e.g., high number of equipment operations, temperature, or vibration). Automatically notifies asset managers and operations to respond to conditions that increase the probability of equipment failure.
Dynamic Capability Rating	Dynamic capability rating can be achieved through real-time determination of an element's (e.g., line, transformer etc.) ability to carry load based on electrical and environmental conditions.
Fault Current Limiting	Fault current limiting can be achieved through sensors, communications, information processing, and actuators that allow the utility to use a higher degree of network coordination to reconfigure the system to prevent fault currents from exceeding damaging levels.
Customer Level	
Customer Electricity Use Optimization	Customer electricity use optimization is possible if customers are provided with information to make educated decisions about their electricity use. Customers should be able to optimize toward multiple goals such as cost, reliability, convenience, and environmental impact.
Real-time Load Measurement and Management	This function provides real-time measurement of customer consumption and management of load through Advanced Metering Infrastructure (AMI) systems (smart meters, two-way communications) and embedded appliance controllers that help customers make informed energy use decisions via real-time price signals, time-of-use (TOU) rates, and service options.

C

EXAMPLE APPLICATION: VOLT/VAR OPTIMIZATION WITH CONSERVATION VOLTAGE REDUCTION

This appendix provides an example of the major activities described in this guidebook: the Summary Project Overview and the Research Plan, as partially completed for a sample Volt/Var Optimization/Conservation Voltage Reduction project.

A summary-level document such as the Summary Project Overview is useful in several respects. In the early planning stages the process and format are useful for advanced planning of some of the important steps that might forestall progress if encountered later. A formal document along these lines may also be useful for communicating with regulators, policy-makers, or management in the early stages of the project, perhaps prior to approval. Parts of it can also function as front matter for a case study or final project report as might be viewed by the public or other utilities.

Project Overview

The demonstration will implement and evaluate the Smart Grid technologies used to apply conservation voltage reduction (CVR) at the substation level. The demonstration seeks to reduce customer energy usage and reduce feeder losses, providing benefits to multiple stakeholders.

Step 1: **Provide basic project identification information.**

General Information:

Name of Project	VVC/CVR Test on SubPlace Substation
Project Description	Project will employ a locally controlled VVC system consisting of switchable capacitors and regulators coordinated and controlled from the substation.
Lead Organization	XYZ Electric Company
Other Participants	EPRI VVCCo (System Controller Manufacturer)
Project Manager/ Contact Information	John P. Manager / (xxx) xxx-xxxx / jpmanager@smartgrid.com
Planned Project Duration	Jan 2013- Dec 2016
Total Budget	$21,500,000
Government Cost Share	$10,750,000 Matching Funds

Step 2: **Provide a general description of the problem to be solved, baseline, and project goals and objectives**

Project Purpose:

- **Problem or Opportunity Statement:**
  Supplying electricity at the proper voltage is not only desirable for high quality of service, but is regulated by the ANSI C84.1 standard which states that voltage at the residential meter must be within the range between 114.1–126.0 V. The current system of voltage control requires reactive power to flow through the substation from the transmission system. Voltage levels at the substation are near the top of the ANSI range, while voltages at the ends of the feeder segments drop to the lower end of the range. This arrangement causes at least two problems: Losses in transformers and other devices are higher at the higher voltage levels near the substation, and some consumer devices consumer more power than necessary. Further, supplying reactive power from the transmission system causes thermal losses in lines and transformers.

  With a volt/var control system, switchable capacitors supply reactive power at various locations along the feeder, reducing current flow from the substation, reducing losses. Further, actively maintaining a reduced range of voltage from its highest point (usually, but not always, at the substation) to the low-voltage point (usually at the end of the feeder or one of its laterals), allows the average voltage on the feeder to be reduced, imperceptibly lowering customer loads and reducing losses along the feeder.

  The feeders supplied by the SubPlace substation have long been uncontrolled, but voltage issues are now evident, caused by growth in the surrounding area.

- **Project Description**
  The project will outfit the four feeders from the SubPlace substation with locally controlled volt/var system capable of conservation voltage reduction. Reactive power will be supplied at various points along the feeders by controllable capacitors, and voltage control will be accomplished through a combination of line regulators and the substation tap-changing transformer, in addition to switching of capacitors.

- **Current Situation/Business-As-Usual/Baseline Scenario**
  The baseline scenario is complex, as it extends into the future and assumes some modifications to the existing system. Growth in the area served by SubPlace has been steady in recent years owing to commercial development and residential growth in the extremities of Feeder SP3. Power factor has been deteriorating, and the area needs additional voltage support as evidenced by periodic customer complaints. Phases are clearly out of balance, though the extent of imbalance is not clear due to lack of instrumentation. Higher loadings have led to higher losses, and the imbalance has exacerbated voltage-control issues. The base alternative to the VVO/CVR project is a system of capacitors with only local controls, following an effort to balance the phases. Because of growth, several upgrades will be needed during the coming decades.

As new sensors allow updating and verification of circuit planning models, the phase-balancing work will be enabled (in the model and in reality), providing sufficient information to estimate a base plan for the upgrades needed to maintain voltage and reliability in the coming decades, assuming minimal penetration of customer-owned energy resources. Two sets of plans will be developed, one for the technology assumed in the project—VVO controlled from the substation, with CVR—and one for the base plan—conventional capacitors with local controls, with no opportunity for CVR. The Cost/Benefit Analysis will compare these two scenarios in terms of operating costs and capital revenue requirements. While these planning scenarios are composed of forecasted loads, the difference between the two load scenarios will be a matter of the efficacy of CVR, which will be examined experimentally.

- **Project Objectives**
  The project objectives include improving the efficiency of the feeders by reducing line and transformer losses, and improving the efficiency of the transmission system by reducing the need for supplying vars to SubPlace. However, the major objective of the Conservation Voltage Reduction is improving the efficiency of customer energy use by slightly lowering the delivery voltage.

Step 3: Provide a high-level background discussion and project summary.

- **Background**
  - **Description of Utility**
    XYZ Utility is an investor-owned transmission and distribution company operating in the XISO market in the state of MyState. Its service territory is in the southwest portion of the state where its provides electric energy at retail to approximately 70,000 customers. Energy sales were over 1,600 GWh in 2011, with 63% in residential sales, 30% in industrial and large commercial sales, and the remainder in small commercial and street lighting. Annual revenue in 2011 exceeded $160 Million. The company purchases power from a variety of suppliers under contract and complements these wholesale with purchases and sales at Locational Marginal Price (LMP) at five delivery points on its transmission system.

    Map

  - **Market Structure Context**
    The FERC-regulated wholesale market operated by the XISO provides a platform that accommodates both locational spot and bilateral contracts among buyers and sellers. Delivery prices across the transmission network are determined by LMP differences. The market can accommodate physical schedules between suppliers and buyers, but most contracts are financial, allowing generation to be scheduled optimally. Utilities in XISO must purchase capacity including reserves for a 3-year forward period in addition to the current year.

XYZ is a monopoly supplier of electricity to its customers, as retail access has not been authorized in MyState. XYZ's transmission system is operated by XISO as a portion of the wholesale market, and XYZ is compensated through the wholesale tariff.

- **Regulatory Structure Context**
  The company is regulated by the MyState PUC, a 3-member elected board with a staff of 50 analysts and support employees. The commission reviews rate change requests submitted irregularly by the utility, and generally works toward setting rates that provide an allowed rate of return on equity investment, based on staff recommendations. Residential pricing is conventional volumetric pricing that varies by time of year. Commercial and Industrial pricing is more varied, with limited time-of-use offerings, with a voluntary real-time pricing program available for large consumers. Energy and capacity purchases are essentially passed through to consumers with some cost allocations by customer class.

- **The SubPlace VVO/CVR Project**
  - **Geographic Scope of Project**
    The area served by SubPlace is approximately 100 square miles, including an area of rapid growth in the Name Creek area. The area is predominantly residential and commercial, with only a few small industrial sites.
  - **Basic Project Elements:**
    The VVO/CVR project will incorporate 15 remote controlled 600 and 1200 kvar capacitor banks on the three-phase backbones of the feeders. Twelve communicating voltage sensors and six in-line regulators will be deployed. A processor/controller unit will be installed at the substation, and communication among all devices will be wireless.
  - **Enabled Functions:**
    The VVO/CVR project take advantage of the ability of the system both to flatten the voltage profile through regulation and var supply and to lower the profile for customer efficiency.
  - **Expected Impacts:**
    The VVO/CVR project is expected to reduce losses in lines and transformers on the four circuits by supplying sufficient var supply as to show a slightly leading power factor to the system at peak conditions. Reducing the burden of supplying reactive power from the transmission system will reduce losses above and below the SubPlace substation and free up real-power capacity in generators, lines, and substations otherwise consumed by reactive power (though this is not a one-to-one relationship between reduced reactive power and freed real-power capability). However, the greater impact is expected from reduced delivery voltages, especially in areas close to SubPlace where the voltage is currently maintained within the top part of the standard ANSI voltage range in order to allow voltage drop along the feeders. Summer impacts in similar projects have demonstrated about .8% energy consumption reduction for each 1% of head-end voltage reduction. This reduces energy consumption and peak demand.
  - **Expected Benefits:**
    Reducing real power consumption on the feeder and in customer premises ultimately reduces fuel use and emissions out on the power system. The benefits for XYZ customers

will come from lower power purchase costs on the part of the utility, which are passed on to customers, and will be partially offset by higher cost recovery requirements arising from capital investments.

  - **Targeted Groups or Area:**
    Reductions in the cost of losses will be reflected in lower utility operating costs and will ultimately be passed to all customers of the utility. Conservation Voltage Reduction has passive participation for affected customers, but customers may not benefit equally or proportionally, because the benefit is dependent on the amount of voltage change at the customers' premises.

Step 4: Provide high-level project organizational information

Project Organization:

- **Co-Funders**
  The $21 Million project is funded by XYZ Electric and the Government, which is matching the funds invested by XYZ.
- Project Partners and Collaborators
  VVCCo is partnered with XYZ in the project, providing discounts on equipment in exchange for access to data and results. The Government is a partner as well, requiring periodic reports as to the use of funds for equipment and installation, and reports of impacts and benefits in the demonstration phase.
- General description of roles and responsibilities

Role	Responsibility	Contact Name & Contact Information
EPRI Project Manager		
Client Project Manager		
Client Technical Lead (per sub-project)		

- High-Level Project Budget and Timeline

High-level Project Budget and Timeline		Date		2013				2014				2015				2016			
Task	Budget	Begin	Complete	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Project Development																			
Project Summary Development																			
Identify roles & responsibilities																			
Outline project goals and objectives																			
Develop project budget																			
Identify project partners and collaborators																			
Internal Approvals (Budget & Scope)																			
External Approvals (Budget & Scope)																			
Regulatory Approvals																			
Local, State, Federal Approvals																			
Regulatory Commission Approval																			
Pre-Planning & Preparation																			
Equipment Purchases																			
Equipment Installation																			
Marketing Material Development																			
Communication & Customer Recruitment																			
Baseline Measurements																			
Identify quantities and durations for baseline measurement																			
Measure baseline quantities																			
Field Implementation																			
Technology installation (by project phase or sub-project)																			
Data Collection																			
Data collection (start - end)																			
Data processing (start - end)																			
Data analysis (start - end)																			
Reporting																			
Internal reporting (start - end) per requirement																			
DOE reporting (if applicable)																			
Other reporting requirements																			

Technology Description

The demonstration will implement and evaluate the Smart Grid technologies used to apply conservation voltage reduction (CVR) at the substation level. The demonstration seeks to reduce customer energy usage and reduce feeder losses, providing benefits to multiple stakeholders.

Step 5: Describe the technologies, devices, and systems to be deployed

- Description of project elements (technologies, devices, systems, etc.):

Technologies Deployed	Interactions among devices, systems, and operators
Remote Terminal Unit	An intelligent device, located at the substation, that interfaces SCADA and field devices, such as LTC controller, the feeder circuit breaker, and protective relays.
Transformer load tap changer controller	Responds to commands from the controller setting tap position, reporting position and various measurements to the Controller.
Line capacitor bank controls	Receives and responds to commands from the controller and reports data and alarms to VVO controller
SCADA system	Allows operators to issue control commands to various devices, retrieves data from devices and systems, including the VVO Controller, Line Capacitor Controllers, the RTU, and Voltage Sensors.
Distribution Management System (DMS)	Provides interface between human distribution operators, the SCADA system, and various systems providing state information and modeling capability of the distribution system.
Line voltage sensors	Measures voltage where installed, making data available through SCADA
Volt/Var Optimization (VVO) controller	A device that interacts with RTUs and field devices such as line capacitor controllers

Step 6: Describe the functions enabled.

- **Enabled Functions**

  Advanced Voltage/Var Control:

  - Control and optimize supply of circuit vars in order to maintain a flatter voltage profile.

  Conservation Voltage Reduction:

  - Reduce the level of the average delivery-voltage profile.

Step 7: **Describe how the technology will be applied.**

- **Application**

  Volt/Var Optimization (VVO) will be applied to the SubPlace circuits to balance the supply of reactive power with the amount needed, capable of supplying a slight surplus such that the power factor of the substation shows to the transmission system at peak will be slightly leading. The optimization routine is expected to be set to plan and allow switching of capacitors two or three times per 24-hour period.

Upon demonstration of the ability of VVO to control the circuit voltage profile, **Conservation Voltage Reduction (CVR)** will be operated continuously so as to reduce the average circuit delivery voltage without causing voltage to drop below the lower standard limit of 114V. It is anticipated that an average voltage reduction of 3.5% at the substation can be achieved. Reduction will be controlled by substation tap-changing transformers, which will be coordinated with in-line regulators, if present.

Step 8: Describe the expected benefits.

VVO: Reduces line losses and enables CVR
CVR: Reduces energy consumption of some loads and further reduces losses

VVO/CVR are primarily efficiency measures, although VVO may be adapted for voltage control when distributed resources begin to affect voltage profiles on the circuits. As efficiency measures, they ultimately reduce fuel use and emissions, and reduce usage of existing assets, thereby deferring incremental capacity in lines and generators. Locally, however, since XYZ is a T&D company, increasing energy efficiency reduces purchased power costs in terms of both energy and capacity purchased. At the feeder level, incremental capacity is made available through the reduction of both real and reactive power, eventually deferring incremental capacity additions.

Note that the reduction in energy consumption from CVR is expected to be much greater than the reduction in losses from either VVO or CVR. So, a major source of benefit from VVO is that it enables CVR.

Step 9: Describe the expected impacts and performance metrics.

The VVO/CVR project is expected to reduce losses in lines and transformers on the four circuits by supplying sufficient var supply as to show a slightly leading power factor to the system at peak conditions. Reducing the burden of supplying reactive power from the transmission system will reduce losses above and below the SubPlace substation and free up real-power capacity in generators, lines, and substations otherwise consumed by reactive power (though this is not a one-to-one relationship between reduced reactive power and freed real-power capability). However, the greater impact is expected from reduced delivery voltages, especially in areas close to SubPlace where the voltage is currently maintained within the top part of the standard ANSI voltage range in order to allow voltage drop along the feeders. Summer impacts in similar projects have demonstrated about .8% energy consumption reduction for each 1% of head-end voltage reduction. This reduces energy consumption and peak demand.

The performance metric will be an estimated reduction in net real and reactive power at the substation. The reduction in real power measured at the substation will include all losses below that level. Power factor at the transmission node will be estimated to confirm the success of achieving a leading power factor. Operation of the system will be monitored to determine whether the system functions as intended without increasing the number of transformer tap changes, capacitor switching operations, and regulator tap changes.

Developing a Research Plan

This section completes the Research Plan for the example project described above. The research plan includes the Technology Description, which sets the stage for the research needs. The Technology Description states the impacts that are expected from the project, and the Research Plan sets forth the plan to measure the impacts in experimental demonstration. The implementation of the Research Plan provides impact measurements that are used to calculate performance metrics, leading to the estimation of benefits and cost-related impacts for cost/benefit analysis.

Step 10: Define the Research Problem.

- **The Research Problem**

  The research problem in VVC/CVR analysis is to measure how it impacts the feeder and the power system. This cannot be measured directly, of course, so elements of the impact must be estimated from a measurement protocol. The impacts we are interested in are the change in real-power load at the feeder and substation level, as well as the change in var loadings as viewed at the substation.

  The first step of implementation is balancing the phase loadings of the circuits, because one low-voltage phase can limit the average voltage reduction. However, balancing load among the phases of a circuit will itself reduce losses, a low-cost activity (enabled by deployment of additional sensors) that will reduce the incremental benefit of VVO, but enable deeper utilization of CVR capabilities.

  - What are the impacts of phase balancing on losses?
  - What does VVO accomplish in terms of reduction of voltage drop?
  - What level of voltage reduction can be achieved with VVO/CVR?
  - To what extent does VVO/CVR reduce real and reactive power at the feeder head?
  - To what extent does voltage reduction affect the average premises load?
  - Is Power Quality compromised when voltage is reduced?
  - What maintenance needs are introduced by the new equipment?
  - Are tap changes and capacitor switching within normal ranges for device wear?

Step 11: Identify the physical measurements that will be needed.

- **Physical Measurements (from the project area)**

Physical measurements can be read from many smart grid devices, including reclosers, capacitor controllers, breakers, substation transformers, and inline regulators in addition to voltage sensors. Readings for real and reactive power loadings at the feeder breaker exit must be obtained, averaged across hour intervals, at longest. Voltage at the substation must be measured, along with voltages at the various sensors, all averaged across the measurement intervals (i.e., not instantaneous voltage).

During the demonstration period, one or more of the feeders should be outfitted with a Power Quality meter to measure harmonic content away from the substation during the testing of VVO/CVR. Power Quality will also be indicated to some extent by voltage violations relative to the ANSI standard for delivery voltage.

Tap changes, capacitor switching, and regulator movement should be recorded and time-stamped.

All switching activities on the circuits must be recorded as to their time and nature. If portions of the circuit are switched over other sources, or if sections are switched among the feeders at SubPlace, all such actions must be recorded so that the analysts can account for the non-normal conditions in analysis.

Step 12: List relevant external factors and whether they will be collected.

- **External Factors/Measurements**

Because of the analytics methods that must be used to extract the impact of CVR, several important external factors must be measured. Primarily, weather information such as temperature and humidity must be collected on at least an hourly basis in a location closely related to the feeder service area. Any other external (non-power-system) information relevant to feeder loading should be recorded as well. For instance, the full-time school operation schedule, including school holidays, affects the load shape on residential feeders.

In addition to weather data, real and reactive power loads for the nearby OtherPlace substation will be measured and recorded for the same period as for SubPlace. OtherPlace has a similar load makeup as SubPlace and is expected to be highly correlated with SubPlace. OtherPlace may provide a useful reference for use in regression analysis. As with SubPlace, any switching activity or outages that would affect the measured loads should be recorded and made available to the project, as well as any community occurrences that may have affected loads differently from SubPlace.

Step 13: **Define the baseline quantities or methods of estimation.**

- **Baseline Quantities**

  The baseline *scenario* is complex, as it extends into the future and assumes some modifications to the existing system. Growth in the area served by SubPlace has been steady in recent years owing to commercial development and residential growth in the extremities of Feeder SP3. Power factor has been deteriorating, and the area needs additional voltage support as evidenced by periodic customer complaints. Phases are clearly out of balance, though the extent of imbalance is not clear due to lack of instrumentation. Higher loadings have led to higher losses, and the imbalance has exacerbated voltage-control issues. The base alternative to the VVO/CVR project is a system of capacitors with only local controls, following an effort to balance the phases. Because of growth, several upgrades will be needed during the coming decades.

  As new sensors allow updating and verification of circuit planning models, the phase-balancing work will be enabled (in the model and in reality), providing sufficient information to estimate a base plan for the upgrades needed to maintain voltage and reliability in the coming decades, assuming minimal penetration of customer-owned energy resources. Two sets of plans will be developed, one for the technology assumed in the project—VVO controlled from the substation, with CVR—and one for the base plan—conventional capacitors with local controls, with no opportunity for CVR. The Cost/Benefit Analysis will compare these two scenarios in terms of operating costs and capital revenue requirements. While these planning scenarios are composed of forecasted loads, the difference between the two load scenarios will be a matter of the efficacy of CVR, which will be examined experimentally. For both planning scenarios the base load scenario will be based on the post-phase-balancing loads, which will be forecasted based on measurements taken after the phases have been balanced.

  After the VVO/CVR system is installed and tested, the efficacy of CVR will be examined through two years of day-on/day-off operation that will provide data to feed a regression analysis. The regression analysis, in essence, estimates the baseline load for comparison with the CVR load. Because the CVR analysis will be used to estimate post-CVR feeder-load forecasts, the CVRf calculations, which characterize the average % change in load for a % change in voltage, will be done using a load-weighted average voltage change based on measurements taken at various points along the circuit.

  Other baselines are less complex, but are model/estimate based. The impact of phase balancing on losses is best determined using the planning models. This activity can be described technically and evaluated in terms of its benefits and cost to implement (which is expected to be low following installation of sensors). The sensors are sunk by the time the work is done, but a cost/benefit analytical treatment of the sensor-plus-balancing activities may be useful for determining whether such activities are worth pursuing on other feeders. At least a year of measurement with sensors would be required for the most thorough phase-balancing estimates, but measurements through a peak season may suffice. In this case the first peak season following sensor installation will be used to inform the phase balancing. [Each of the research questions from Step 10 requires similar forward-looking analysis of what comparison will be made to answer the question, and how its components will be constructed. The forethought here, anticipating and formulating the components of the CBA, is necessary because experimental results are inform the analysis. The questions to be visited in the CBA establish requirements for experimental results, so this step is necessary in order to plan for the experiments. The research questions are related to the hypotheses, developed next.]

Step 14: Construct formal hypotheses to be tested through experimentation.

- **Hypotheses**

  [At least one hypothesis should be developed for each research question of the research problem.]

  - VVO reduces the drop in the feeder voltage profile to a greater extent than with locally controlled capacitors.
  - Combined VVO and CVR enables feeder voltage reduction to a greater extent that with locally controlled capacitors.
  - Combined VVO and CVR will reduce real power demands on the feeders.
  - Power Quality, in terms of voltage violations and harmonics, can be maintained within standards while operating VVO/CVR.
  - Switching of capacitors and tap changing on regulators and capacitors can be maintained within normal ranges while operating VVO/CVR, implying that maintenance requirements will be normal.

Step 15: Specify experiments and how they will be conducted.

- **Experiments**

  [Ideally, the schedule of experiments would be aimed at determining whether each hypothesis is supported by evidence. Here, the investigative period in the first year addresses the first and second hypotheses, and perhaps the fourth. The third hypothesis is addressed in the second year of continuous operation and measurement after the bounds of future operation have been determined.]

  Following phase balancing, a one-year period of continuous day-on/day-off operation will proceed to provide data for analysis while testing the ability of the system to operate at different levels of voltage reduction. During this period the loadings and voltages will be recorded at each device on each circuit, which will be used to analyze the voltage profile and the changes in load. Voltage will be alternated among three states of voltage variation (for example, 0%, -2%, and -4% reduction) while monitoring voltage extremes and power quality. The 0% condition will feature capacitors operated on local controls, as close as possible to the condition specified in the baseline scenario. As soon as engineers are comfortable with the level of voltage reduction that can be achieved without difficulty, the system will be put into a simple alternation between normal voltage and reduced voltage for the remainder of the two-year experiment period.

Step 16: Develop a detailed project timeline around experiment plans.

Detailed Project Timeline	
Task	**Deadline**
Project Design	
Research Plan development	
Establish baseline(s)	
Identify baseline measurments	
Schedule for baseline data gathering	
Document experimental design	
Identify hypotheses	
Test Plan development	
Specify experiment schedules	
Experiment 1	
Experiment 2	
Experiment 3	
Data Collection Plan Development	
Data Collection Protocol development	
Data Storage Protocol development	
Data Retrieval Protocol development	
Data Screening Protocol development	
Smart Grid Technology Deployment	
Schedule for data gathering	
Schedule for data analysis	
Schedule for reporting results	

Step 17: Provide data collection instructions, including collection points and time intervals for each measurement

- **Data measurement requirements:**
  - Feeder real and reactive power, voltage, measured in 15-minute intervals at the breaker
  - Voltage, and real/reactive power flow, at each measuring device on the feeder, i.e., capacitors, reclosers, and regulators capable of reporting, and voltage sensors at points near critical low-voltage points on the feeder
  - Tap position and voltage on the tap-changing transformer, time stamped
  - Kvar supplied for each bank of capacitors, by 15-minute interval.

Step 18: Specify data testing, screening, storage and retrieval protocols

- **Data testing and screening protocols:**

  Readings from all sensors and meters should be tested to verify that the readings are valid and are consistent with the physical situation.

- **Data storage and retrieval protocol:**

  Specifies the data items, their duration, and their specific location, in either a special purpose database or among the various databases the utility maintains.

IT Contact	
Field Measurement Contact	
Storage Platform/System	
Data retrieval Contact/Platform	

Step 19: Specify algorithms for calculation of impacts and impact metrics.

- **Algorithms**

  Regression analysis will be used to extract the real-power impact of voltage reduction from the measured load data, selecting among the available weather, comparable-feeder, and ancillary data that are available. The analysis will be done hourly from compiled interval data, but will be done for seasonal periods with similar weather patterns, if possible. For instance, summer months may be done as a unit with winter and shoulder months being done in separate groups. Experience suggests that these periods will show different results, consistent with the change in load-device composition over the course of a year, isolating the cooling months from the heating months.

  The result of regression analysis will be a formula estimating the feeder load in the form of a linear combination of the observation data, including a term composed of variable that indicates the voltage state, whether normal or reduced, and its coefficient. The coefficient of the voltage variable is the average change in load to the change in voltage represented by the variable. For instance, if the voltage-state variable is a 1 when voltage is reduced 2.5% and a zero when voltage is normal, then the coefficient of the voltage-state variable will be the average change in load associated with a 2.5% voltage reduction.

  The CVRf is the %-change in load per %-change in voltage, or %ΔkW/%ΔV, so some calculation is required to convert the coefficient, which is in units of demand, into a percentage. To calculate the %-change in load, the coefficient is divided by the average load for the period of analysis, modified to counteract the effect of the voltage reduction. That is, the average load is estimated as what it would have been absent the voltage reduction, obtained by adding the load reduction back to the load.

Other impacts and metrics include power factor at substation in VVO mode, and weighted average voltage change.

Step 20: Estimate physical impacts from measurement data

The estimation of physical impacts, for the purposes of a CBA, involve extrapolation to future periods. Naturally, assumptions must be made as to how current-day experimental results can be applied to future years. Planners must do this routinely, and a key feature of such extrapolations is reasonableness. Another feature of extrapolation is flexibility within the bounds of reasonableness, and relative ease of altering assumptions for exploring bounds. If it is reasonable to allow a constant levels of impacts, even if it is an upper bound, then a scenario of constant impacts can be run to estimate their value. If there exists logic for declining impacts, then scenarios can be constructed on that basis. The analysis provides valid what-if information.

In any case, it is advisable to extrapolate the physical impacts for the term of the study, and then apply cost or price rates to the stream of physical impacts. The reason for this is that it is important to think through the physical changes that may occur across the span of time, and it is easy to skip this step if conversion to monetary terms is done first.

Suppose in a study of a VVO/CVR system we estimate that we can reduce feeder loadings by 3% year-round. For study purposes we could assume a scenario of 3% reduction for 15 years based on a 15-year forecast of feeder load. Or if that seems speculative, we could allow the percentage to decline to 2% or 1% over time, on the logic that conversions to energy-efficient devices and appliances might be occurring, and would be less sensitive to supply voltage. Appliance saturation data might support such a trajectory, but substantial analysis may not be warranted. We can make use of the information derived from a constant-impact scenario and a declining-impact scenario, in the end asking whether the benefits in either case are sufficient to overcome the costs.

Table7-1
Example Impacts for Layers of Project Investments

		Year1	Year2	Year3	Year4	Year5	Year6	Year7	Year8	Year9	Year10
Baseline Scenario											
Feeder Losses, Baseline Scenario	MWh	3,504	3,557	3,610	3,664	3,719	3,775	3,831	3,889	3,947	4,006
Capacitors Added, Local Controls											
Feeder Losses	MWh	3,066	3,112	3,159	3,206	3,254	3,303	3,352	3,403	3,454	3,506
Loss Reduction	MWh	438	445	451	458	465	472	479	486	493	501
Capacitors Added + VVO/CVR											
Feeder Losses, w/caps + VVO/CVR	MWh	2,978	3,023	3,068	3,114	3,161	3,209	3,257	3,306	3,355	3,405
Loss Reduction w/caps + VVO/CVR	MWh	88	89	90	92	93	94	96	97	99	100
Consumption Reduction w/caps + VVO/CVR	MWh	2,628	2,667	2,707	2,748	2,789	2,831	2,874	2,917	2,960	3,005
Energy Savings w/caps + VVO/CVR	MWh	2,716	2,756	2,798	2,840	2,882	2,925	2,969	3,014	3,059	3,105

Step 21: Convert physical impacts to monetary values

XYZ Electric operates in a wholesale market with locational marginal prices determined by a bid-based security-constrained economic dispatch. XYZ owns no generation, and buys its energy supply from various market sources. It is also required to purchase capacity, including reserves, in the ISO's capacity market. While XYZ has some contractual obligations for power supply, it also buys some power in the spot market at its locational marginal price. If at any time it has more contractual energy than it can consume, it essentially sells its surplus at its locational marginal price. So, for incremental changes in load or losses, the appropriate value for XYZ's customers is the locational marginal price. Similarly, an appropriate price for incremental changes in peak load is the market capacity price, capped by the administratively determined Cost Of New Entry. But identifying the pricing point does not provide the needed data; we need estimates of these quantities for the next 15 or 20 years. Similarly, changes in O&M, for positive or negative, must be extrapolated for the period, as well as costs for capital investments if there are changes in future investment requirements brought about by the changes in the project. For example, reducing load and losses may allow a substation upgrade to be deferred by one or more years, taking place five years hence. Deferral generally saves money in present-value terms, despite that it generally means an increase in the prices of equipment.

Many utility planners are accustomed to long-term extrapolations of such quantities, sometimes using models to account for large physical system changes that are represented in long-term plans, changes such as new power plants, transmission lines, or retirements. In other cases, extrapolations are based on long-range price escalation rates for various components of cost, such as natural gas or labor. Often such assumptions can be found in economic models und7erlying the company's load forecast.

Table7-2
Example Monetized Benefits, with Present Value

		Present Value	Year1	Year2	Year3	Year4	Year5	Year6	Year7	Year8	Year9	Year10
Marginal Cost of Energy	$/MWh		40.0	46.4	47.9	50.0	51.4	53.9	57.1	59.8	62.1	66.0
Baseline Scenario												
Cost of Losses, Baseline Scenario	k$	**1,403.8**	140.2	165.0	173.0	183.3	191.1	203.3	218.7	232.6	245.1	264.3
Capacitors Added, Local Controls												
Cost of Losses	k$	**1,228.3**	122.6	144.4	151.4	160.4	167.3	177.9	191.4	203.6	214.5	231.3
Loss Savings	k$	**175.5**	17.5	20.6	21.6	22.9	23.9	25.4	27.3	29.1	30.6	33.0
Savings attributable to Capacitors	k$	**175.5**	17.5	20.6	21.6	22.9	23.9	25.4	27.3	29.1	30.6	33.0
VVO/CVR												
Cost of Losses	k$	**1,193.3**	119.1	140.2	147.1	155.8	162.5	172.8	185.9	197.7	208.3	224.7
Loss Savings	k$	**35.1**	3.5	4.1	4.3	4.6	4.8	5.1	5.5	5.8	6.1	6.6
Consumption Savings	k$	**1,052.9**	105.1	123.7	129.8	137.5	143.4	152.5	164.0	174.5	183.8	198.2
Savings attributable to VVO/CVR	k$	**1,088.0**	108.6	127.9	134.1	142.0	148.1	157.5	169.5	180.3	189.9	204.9
Total for Project												
Loss Savings	k$	**210.6**	21.0	24.7	26.0	27.5	28.7	30.5	32.8	34.9	36.8	39.6
Consumption Savings	k$	**1,052.9**	105.1	123.7	129.8	137.5	143.4	152.5	164.0	174.5	183.8	198.2
Savings attibutable to Project	k$	**1,263.4**	126.1	148.5	155.7	164.9	172.0	183.0	196.8	209.4	220.6	237.9
Present-Worth Factor	8%		1.0000	0.9259	0.8573	0.7938	0.7350	0.6806	0.6302	0.5835	0.5403	0.5002

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TEMPLATES FOR COST/BENEFIT ANALYSIS

COST/BENEFIT ANALYSIS PROCESS CHECKLIST

PROJECT OVERVIEW DOCUMENTATION

Project Overview

☐ **Step 1:** Provide basic project identification information
☐ **Step 2:** Describe the project and its major objectives
☐ **Step 3:** Provide relevant Background information
☐ **Step 4:** Provide a high-level budget and project timeline

TECHNOLOGY DESCRIPTION.

☐ **Step 5:** Describe the technologies, devices, and systems to be deployed
☐ **Step 6:** Describe the functions enabled
☐ **Step 7:** Describe how the technology will be applied.
☐ **Step 8:** Describe the expected benefits
☐ **Step 9:** Describe the expected impacts and performance metrics

DEVELOPING A RESEARCH PLAN

Research Plan

☐ **Step 10:** Define the research problem.
☐ **Step 11:** Identify the physical measurements
☐ **Step 12:** Describe relevant external factors.
☐ **Step 13:** Define the baseline quantities or methods of estimation
☐ **Step 14:** Construct formal hypotheses to be tested
☐ **Step 15:** Specify the experiments and how conducted
☐ **Step 16:** Develop a detailed project timeline
☐ **Step 17:** Provide data collection instructions, including collection points and periods
☐ **Step 18:** Specify data testing, screening, storage and retrieval protocols
☐ **Step 19:** Specify algorithms for calculation of impacts

ESTIMATING PROJECT IMPACTS, COSTS, AND BENEFITS

Cost/ Benefit Analysis

☐ **Step 20:** Estimate physical impacts from measurements
☐ **Step 21:** Monetize estimates of physical impacts
☐ **Step 22:** Estimate costs incurred by customers per year for baseline and project
☐ **Step 23:** Estimate utility costs by function/classification for baseline and project
☐ **Step 24:** Summarize Costs and benefits

Template for Summary Overview and Research Plan Development

Project Overview

Overview statement:

Step 1: Provide basic project identification information.

General Information:

Name of Project	
Project Description	
Lead Organization	
Other Participants	
Project Manager/ Contact Information	
Planned Project Duration	
Total Budget	
Government Cost Share	

Step 2: Provide a general description of the problem to be solved, baseline, and project goals and objectives

Project Purpose:

- **Problem or Opportunity Statement:**

- **Project Description**

- **Current Situation/Business-As-Usual/Baseline Scenario**

- **Project Objectives**

Step 3: Provide a high-level background discussion and project

- **Background**
    - **Description of Utility**

Map

-
    - **Market Structure Context**
    - **Regulatory Structure Context**

- **Project Description**
  - **Geographic Scope of Project**
  - **Basic Project Elements:**
  - **Enabled Functions:**
  - **Expected Impacts:**
  - **Expected Benefits:**
  - **Targeted Groups or Area:**

Step 4: Provide high-level project organizational information

Project Organization:

- **Co-Funders**

- **Project Partners and Collaborators**

- **General description of roles and responsibilities**

Role	Responsibility	Contact Name & Contact Information
EPRI Project Manager		
Client Project Manager		
Client Technical Lead (per sub-project)		

- **High-Level Project Budget and Timeline**

High-level Project Budget and Timeline		Date		2013				2014				2015				2016			
Task	Budget	Begin	Complete	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Project Development																			
Project Summary Development																			
Identify roles & responsibilities																			
Outline project goals and objectives																			
Develop project budget																			
Identify project partners and collaborators																			
Internal Approvals (Budget & Scope)																			
External Approvals (Budget & Scope)																			
Regulatory Approvals																			
Local, State, Federal Approvals																			
Regulatory Commission Approval																			
Pre-Planning & Preparation																			
Equipment Purchases																			
Equipment Installation																			
Marketing Material Development																			
Communication & Customer Recruitment																			
Baseline Measurements																			
Identify quantities and durations for baseline measurement																			
Measure baseline quantities																			
Field Implementation																			
Technology installation (by project phase or sub-project)																			
Data Collection																			
Data collection (start - end)																			
Data processing (start - end)																			
Data analysis (start - end)																			
Reporting																			
Internal reporting (start - end) per requirement																			
DOE reporting (if applicable)																			
Other reporting requirements																			

Technology Description

- **High-Level Statement Describing Technology to be Deployed**

Step 5: Describe the technologies, devices, and systems to be deployed

- **Description of project elements (technologies, devices, systems, etc.):**

Technologies Deployed	Interactions among devices, systems, and operators

Smart Grid Assets	Functions												
	Transmission		Distribution						Substation			Customer	
	Flow Control	Wide Area Monitoring and Viasualization	Adaptive Protection	Automated Feeder Switching	Automated Islanding and Reconnection	Automated Volt/VAR Control	Enhanced Fault Protection	Real-time Load Transfer	Diagnosis & Notification of Equipment Condition	Dynamic Capability Rating	Fault-Current Limiting	Customer Electricity Use Optimization	Real-time load Measurement and Management
Advanced Interrupting Switch							●						
AMI/Smart Meters						●						●	●
Controllable/regulating Inverter					●	●							
Customer EMS/Display Portal												●	
Distribution Automation			●	●	●	●		●					
Distribution Management System			●	●	●	●		●		●			●
Enhanced Fault Detection Technology							●						
Equipment Health Sensor									●	●			
FACTS Device	●												
Fault Current Limiter											●		
Loading Monitor								●	●	●			
Microgrid Controller					●								
Phase Angle Regulating Transformer	●												
Phasor Measurement Technology		●											
Smart Appliances and Equipment (Customer)												●	
Software – Advanced Analysis/Visualization		●								●			
Two-way Communications (high bandwidth)		●	●	●	●	●		●					●
Vehicle to Grid 2-way power converter													
VLI (HTS) cables	●												

Step 6: Describe the functions enabled.

- **Enabled Functions**

Step 7: Describe how the technology will be applied.

- **Application**

Benefits			**Functions**															
			Trans-mission		**Distribution**						**Substation**			**Customer**		**Energy Resources**		
			Flow Control	Wide Area Monitoring & Visualization	Adaptive Protection	Automated Feeder Switching	Automated Islanding and Reconnection	Automated Volt/VAR Control	Enhanced Fault Protection	Real-time Load Transfer	Diagnosis & Notification of Equipment Condition	Dynamic Capability Rating	Fault Current Limiting	Customer Electricity Use & Optimization	Real-time Load Measurement and	Distributed Generation	Stationary Electricity Storage	Plug-in Electric Vehicles
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						●		●				●	●		●	
	Electricity Cost Savings	Reduced Electricity Cost												●			●	
Reliability	Power Interruptions	Reduced Sustained Outages			●	●	●		●		●				●	●	●	●
		Reduced Major Outages		●			●								●			
		Reduced Restoration Cost			●	●			●		●							
	Power Quality	Reduced Momentary Outages							●	●							●	
		Reduced Sags and Swells							●								●	
Environ-mental	Air Emissions	Reduced CO_2 Emissions	●			●		●						●	●	●	●	●
		Reduced SOx, NOx and PM-10 Emissions	●			●		●						●	●	●	●	●
Security	Energy Security	Reduced Oil Usage (not monetized)				●					●				●			●
		Reduced Wide scale Blackouts		●					●			●						

Step 8: **Describe the expected benefits.**

Step 9: **Describe the expected impacts and performance metrics.**

Developing a Research Plan

This section completes the Research Plan for the example project described above. The research plan includes the Technology Description, which sets the stage for the research needs. The Technology Description states the impacts that are expected from the project, and the Research Plan sets forth the plan to measure the impacts in experimental demonstration. The implementation of the Research Plan provides impact measurements that are used to calculate performance metrics, leading to the estimation of benefits and cost-related impacts for cost/benefit analysis.

Step 10: Define the Research Problem.

- **The Research Problem (Questions to be addressed through experimentation.)**

Step 11: Identify the physical measurements that will be needed.

- **Physical Measurements (from the project area)**

Step 12: List relevant external factors and whether they will be collected

- **External Factors/Measurements**

Step 13: Define the baseline quantities or methods of estimation.

- **Baseline Quantities**

Step 14: Construct formal hypotheses to be tested through experimentation.

- **Hypotheses**
  [At least one hypothesis should be developed for each research question of the research problem.]

Step 15: Specify experiments and how they will be conducted.

- **Experiments**

Step 16: **Develop a detailed project timeline around experiment plans.**

Detailed Project Timeline	
Task	**Deadline**
Project Design	
Research Plan development	
Establish baseline(s)	
Identify baseline measurments	
Schedule for baseline data gathering	
Document experimental design	
Identify hypotheses	
Test Plan development	
Specify experiment schedules	
Experiment 1	
Experiment 2	
Experiment 3	
Data Collection Plan Development	
Data Collection Protocol development	
Data Storage Protocol development	
Data Retrieval Protocol development	
Data Screening Protocol development	
Smart Grid Technology Deployment	
Schedule for data gathering	
Schedule for data analysis	
Schedule for reporting results	

Step 17: **Provide data collection instructions, including collection points and time intervals for each measurement**

- Data measurement requirements:

Step 18: Specify data testing, screening, storage and retrieval protocols

- **Data testing and screening protocols:**

- **Data storage and retrieval protocol:**

  Specifies the data items, their duration, and their specific location, in either a special purpose database or among the various databases the utility maintains.

IT Contact	
Field Measurement Contact	
Storage Platform/System	
Data retrieval Contact/Platform	

Step 19: Specify algorithms for calculation of impacts and impact metrics.

- **Algorithms**

Step 20: Estimate physical impacts from measurement data

- **Physical impacts, by year, for each year of the CBA**

Impact	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10

Step 21: Convert physical impacts to monetary values

- **Monetary Benefits, by year, for each year of the CBA**

Benefit	PV	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10

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