U.S. DEPARTMENT OF ENERGY | Office of Electricity Delivery and Energy Reliability

USER GUIDE FOR THE U.S. DEPARTMENT OF ENERGY SMART GRID COMPUTATIONAL TOOL (SGCT)

Guide for SGCT Version 2.0

Prepared for:
Department of Energy

Navigant Consulting, Inc.
77 S. Bedford Street
Suite 400
Burlington, MA 01803

781.270.0101
www.navigant.com

August 2011

Table of Contents

List of Tables

List of Figures

Preface

This document provides an introduction to the Department of Energy (DOE) Smart Grid programs, a description of the DOE smart grid cost benefit analysis methodology, an overview of the Smart Grid Computational Tool (SGCT) architecture, and step-by-step instructions for using the SGCT. The appendix provides further detail about the methodology, calculations, and assumptions used in the SGCT.

Disclaimer
The work presented in this SGCT and user guide represents the best efforts and judgments based on the information available at the time that these materials were prepared by Navigant Consulting, Inc (Navigant). Navigant is not responsible for the reader's use of or reliance upon the report, or any decisions based on the results of the SGCT. Navigant does not make any representations or warranties, expressed or implied. Users of this tool are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the tool, or the data, information, findings and opinions contained in the tool. This tool is not meant to be used as a budgeting or planning tool and is for educational purposes only. It in no way is meant to supplant discussion between planning engineers and vendors, professionals and experts.

1.0 Introduction

The U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) is charged with leading national efforts to modernize the electric grid, enhance energy infrastructure reliability and security, and facilitate recovery from disruptions in electric power supply. In carrying out this mission the OE, along with utilities and other entities, are investing funds to demonstrate and deploy smart grid technologies and infrastructure through the American Recovery and Reinvestment Act (ARRA) Smart Grid Investment Grant (SGIG) program and Smart Grid Demonstration (SGD) program. The intent of these programs is to collect sufficient real-world field data to verify the costs, performance, and benefits of smart grid technologies and systems operating on the electric grid.

OE created a Smart Grid Cost-Benefit Analysis (CBA) team to develop a standard methodology for evaluating the performance, benefits, and costs of all smart grid field projects. To develop this approach, the CBA team defined a standardized set of smart grid assets, functions, and benefits as well as guidelines for providing data to OE so it can calculate associated benefits. This approach allows the cost and benefits of all smart grid projects to be evaluated consistently, including projects from the SGIG and SGD programs.

The functionality that smart grid assets and systems enable can be translated into monetary value based on the benefits they provide. In order to facilitate such evaluation, Navigant Consulting, Inc. (Navigant) developed the Smart Grid Computational Tool (SGCT) based on the approach developed by the CBA team. This document provides comprehensive instructions for using the SGCT and explains the evaluation methodology.

The SGCT is an Excel-based model that allows the user to identify the functions to be demonstrated by a smart grid project and to calculate the costs and benefits in order to estimate the project's overall value. The tool can be used to analyze real-world data or hypothetical scenarios.

The SGCT is designed to be used by a number of different stakeholders, including:

- The DOE program managers, staff and contractors
- DOE SGIG and SGD program Recipients
- Other interested groups (e.g. electric utilities, industry groups, advocacy groups, researchers, regulators, the interested public).

DOE Program Managers, staff, and contractors can use the SGCT to calculate and track the costs and benefits of the smart grid technologies deployed by DOE through the SGIG and SGD programs. By aggregating the analyses from all of the various projects, DOE will be able to consider broader impacts of smart grid technologies for the nation, specifically on the following areas:

- **Reducing Peak Demand** - The extent to which smart grid technology influences peak demand reduction through the application of smart devices, the change in consumer behavior, and enabling greater use of renewable and distributed resources;

- **Improving Asset Utilization and Operational Efficiency** - The extent to which centralized and distributed generation, transmission, and distribution assets are better utilized through demand-side management, system optimization, and improved system visualization and awareness resulting in deferral of infrastructure investments;

» **Enabling Distributed Energy Resources and Renewable Energy** - The extent to which additional penetration or additional features of distributed energy resources and renewable energy are implemented due to the automation, control, and sensing abilities of the smart grid;

» **Reducing Greenhouse Gas Emissions** - The extent to which a smart grid might lead to reduced emissions of environmental pollutants and reliance on foreign-supplied fuels;

» **Improving Reliability and Power Quality**- The extent to which reliability is improved through the application of smarter sensing, communications, control devices, and integrated grid management systems.

Furthermore, DOE can use the SGCT to analyze SGIG and SGD project data to determine the incremental benefits of the programs. These analyses will help the DOE understand the impact of its investments on the growth and implementation of the smart grid, thereby helping the DOE refine its strategy with respect to encouraging investment in future smart grid technologies.

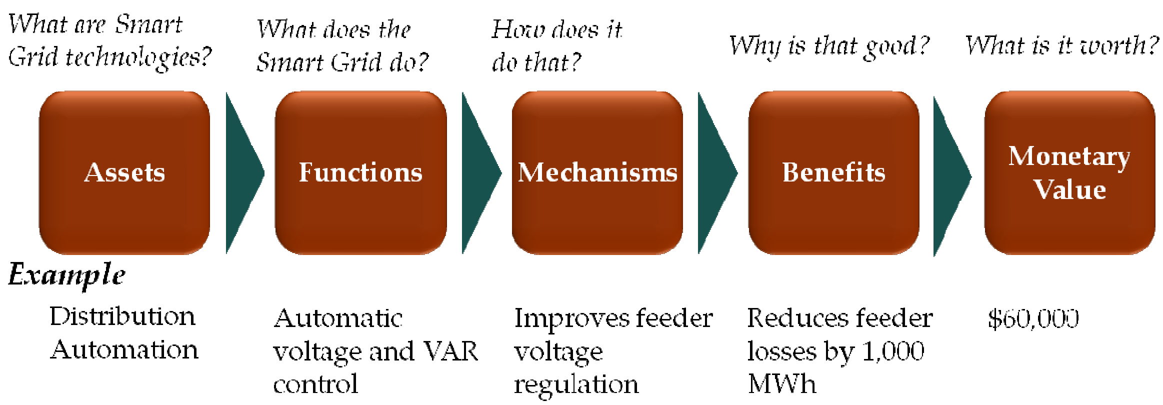
Other stakeholders can use the SGCT to compare project benefits and costs and to gain a clearer understanding of the value of smart grid technology. The SGCT can be used to analyze costs and benefits under different scenarios and assumptions, which can further define the risks and potential of a particular project. Insights provided by the SGCT can be used to justify future smart grid investment.

2.0 Analytical Framework

2.1 Determining Smart Grid Benefits

The SGCT characterizes smart grid projects by identifying the technology (assets) that will be installed and identifying what that technology will do (functions and mechanisms). Based on this characterization, the SGCT identifies the economic, reliability, environmental, and security benefits the smart grid project will yield. Understanding this methodology in depth will help the user utilize the tool more effectively as well as appreciate the analytical rigor of the tool. Figure 1 depicts the overall methodology that the tool employs to determine the monetary value of implementing smart grid technology.

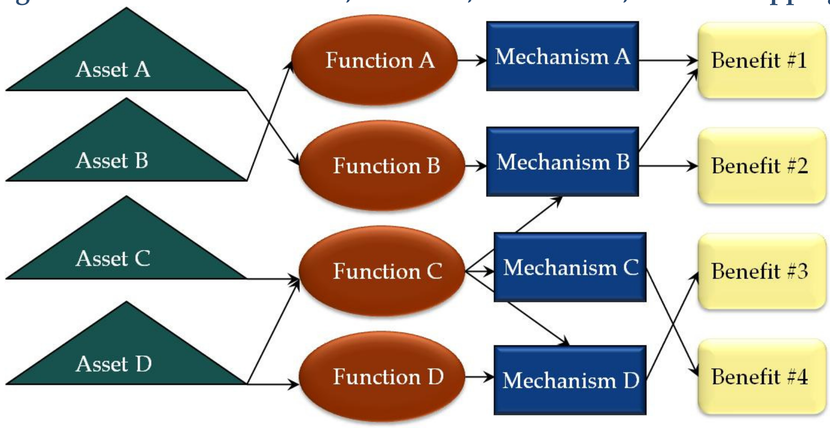
Figure 1. Translation of Smart Grid Assets to Monetary Value



The first step in identifying a project's benefits and associated monetary value is to identify the assets (smart grid technologies) to be deployed. These assets produce a list of possible functions. Functions describe what the smart grid does. Next, each function selected produces a unique list of possible mechanisms, from which the relevant items must again be selected. Mechanisms describe the specific ways the smart grid exercises each function. The final list of functions and associated mechanisms is mapped to a list of achievable smart grid benefits. Finally, if project data are available, the monetary value of each realized benefit can be calculated. Monetary value of project benefits can be aggregated or used directly in a cost-benefit analysis. The value of the benefits can be attributed to ratepayers, utilities, society, or a combination of these parties depending on the nature of the benefit. However, the SGCT does not ascribe benefits to particular constituencies but instead aggregates all benefits.

The final list of smart grid project benefits is derived from known relationships among project assets, functions, mechanisms and benefits. As depicted by Figure 2, these are typically complex relationships that can involve multiple assets mapping to multiple functions, mechanisms, and benefits. Therefore, exploring each portion of this overall relational web separately is appropriate in order to obtain a better overall understanding of the methodology as a whole.

Figure 2. Illustration of Asset, Function, Mechanism, Benefit mapping



2.2 Relationships of Assets to Functions

The first step is to identify the smart grid assets that a project will implement. Smart grid assets can be used together to support different types of functions which result in smart grid benefits. These assets can be grouped based on their location on the grid and could include:

- Advanced Interrupting Switch
- Advanced Metering Infrastructure (AMI)/Smart Meter
- 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 Charging Station
- Very Low Impedance (High Temperature Superconducting) Cables
- Distributed Generator (diesel, PV, wind)
- Electricity Storage device (e.g., battery, flywheel, PEV etc)

Each item on the list above more or less represents an asset category in which a host of smart grid technologies could be included. Table A-1in Appendix A: Asset, Function, and Benefit , provides a more detailed description of each asset.

These assets can be implemented to modernize the delivery and use of electricity by enabling fifteen functions listed below.

- Fault Current Limiting
- Wide Area Monitoring and Visualization and Control
- Dynamic Capability Rating
- Power Flow Control
- Adaptive Protection
- Automated Feeder and Line 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
- Storing Electricity for Later Use
- Distributed Production of Electricity

These functions describe in broad terms the different ways in which smart grid technology can be used to improve the reliability, efficiency, operation, and security of the electrical grid. Table A-2 in Appendix A: Asset, Function, and Benefit , provides a more detailed description of each function. Depending on which smart grid assets are being installed, one or more of the functions is possible. The relationship between smart grid assets installed and possible functions is illustrated in Table 1.

Table 1. Smart Grid Assets and Functions

Smart Grid Assets	Functions														
	Delivery												Use	Other	
	Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Power Flow Control	Adaptive Protection	Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
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 Charging Station													•		
Very Low Impedance (High Temperature Superconducing) cables				•											
Distributed Generator (diesel, PV, wind)								•							•
Electricity Storage device (e.g., battery, flywheel, PEV etc)								•						•	

Because each function describes a broad range of related capabilities that a smart grid asset or combination of assets can enable, the exact way in which a function will be expressed must be understood before the resulting benefits can be specified. Therefore, each function has a unique set of possible mechanisms associated with it. These mechanisms are very descriptive in nature and their purpose is to further specify how a function will be utilized in a given project. For example the **Automated Feeder and Line Switching** function can be utilized to:

- Reduce truck rolls
- Reduce fault location isolation service restoration (FLISR) time
- Reduces manual labor hours associated with line switching
- Reduces manual labor hours associated with restoration

Each of the bullet points above is a mechanism of the Automated Feeder and Line Switching function. However, a project with this functionality might not use all the mechanisms described above. Instead, only a subset may be expressed. For example, consider a project implementing computer-generated remote switching schemes that will automatically restore power after an outage. This project will reduce FLISR time but if the utility used remote operated switches controlled by a human operator previous to this project then the reduced truck rolls mechanism will not be expressed. Depending on which mechanisms are applicable, the Automated Feeder and Line Switching function will lead to different benefits. So, in the strictest sense, it is the function-mechanism pairing that determines the benefits of a project.

The complete list of mechanisms applicable to all the various functions is too large and varied to list in this guide. Because the mechanisms are meant to be descriptive and self explanatory, a full listing of them here would provide little value. To avoid the unnecessary complication of discussing how function-mechanism pairs map to benefits, this guide will refer to functions with the understanding that all possible mechanisms associated with that function are expressed. This assumption allows the relationship between functions and benefits to be explained in a much clearer and concise way, since functions can be related directly to full range of benefits they could enable.

2.3 Relationships of Functions to Benefits

As assets are mapped to functions, functions are mapped to benefits. Benefits are categorized as Economic, Reliability, Environmental, or Security. As shown in Table 2, these four benefit categories comprise 10 subcategories and 22 individual smart grid benefits. The descriptions of these benefits can be found in Table A-3 in Appendix A: Asset, Function, and Benefit . The relationship between smart grid functions and the expected benefits is illustrated in Table 3. The rationale for the association of benefits with each function is described in Appendix B: Function to Benefit Rationale.

Table 2. List of Smart Grid Benefits

Benefit Category	Benefit Sub-category	Benefit
Economic	Improved Asset Utilization	Optimized Generator Operation Deferred Generation Capacity Investments Reduced Ancillary Service Cost Reduced Congestion Cost
	T&D Capital Savings	Deferred Transmission Capacity Investments Deferred Distribution Capacity Investments Reduced Equipment Failures
	T&D O&M Savings	Reduced T&D Equipment Maintenance Cost Reduced T&D 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
Environmental	Air Emissions	Reduced CO_2 Emissions Reduced SO_X, NO_X, and PM-2.5 Emissions
Security	Energy Security	Reduced Oil Usage Reduced Wide-scale Blackouts

Table 3. Smart Grid Functions and Benefits

Benefits			Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Power Flow Control	Adaptive Protection	Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
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 T&D Equipment Maintenance Cost									•						
		Reduced T&D Operations Cost						•		•							
		Reduced Meter Reading Cost											•				
	Theft Reduction	Reduced Electricity Theft											•				
	Energy Efficiency	Reduced Electricity Losses				•				•			•	•	•	•	•
	Electricty 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										•				•	
Environmental	Air Emissions	Reduced CO_2 Emissions				•		•		•	•		•	•	•	•	•
		Reduced SO_x, NO_x, and PM-10 Emissions				•		•		•	•		•	•	•	•	•
Security	Energy Security	Reduced Oil Usage (not monetized)						•			•		•			•	
		Reduced Widescale Blackouts		•	•												

2.4 Benefit Calculations

The last step in quantifying a project's total benefit is to apply calculations which monetize grid impacts that are measured using various metrics. All data that the SGCT uses to calculate benefits must be collected and entered into the tool by the user.

In order to calculate benefits, the SGCT utilizes two different types of data: baseline data and project data. Baseline data are intended to reflect what the state of the grid would have been during the project period assuming a "no build" scenario (i.e., if the project or equipment under analysis had not been implemented). Project data reflect the actual state of the grid as the smart grid technology is implemented. All benefit assessments rely on the calculated difference between baseline and project data at a given point in time.

The baseline scenario must be defined by the user. If the baseline is defined as above (i.e. assuming a "no build" scenario), the tool calculates the absolute benefit of the smart grid technology itself. In the DOE analysis, the baseline will be defined as the state of the grid had SGIG and SGD funds not been awarded. In this case, the calculated benefit will be the impact of the DOE program itself rather than the absolute impact of the smart grid technology. The SGCT is an extremely flexible and dynamic tool; the user has the ability to alter what the output will mean depending on how the baseline dataset is defined. For detailed explanations of each individual benefit calculation methodology, the reader should refer to Appendix C: Benefit and Cost Calculations. For detailed explanation of the baseline data concept, the reader should refer to Appendix D.1 The Baseline Concept.

To calculate benefits, SGCT users must have a five-year projection of baseline data and between one and five years of project data[1] for each required input. The inputs that the user must enter are determined and presented to the user automatically by the tool according to what benefits the project is expected to yield[2]. Inputs may be in the form of raw data (such as hourly load data) or in analyzed form (such as line losses). For a detailed explanation of each input, the reader should refer to Appendix D.2 Inputs.

Although at most five years of project data can be entered into the SGCT, the tool can calculate benefits out to the year 2040.[3] This is accomplished primarily by applying escalation factors such as inflation, energy price growth, load growth, and population growth to inputs. The tool contains default escalation factors. All factors can be reviewed and changed by the user at runtime.

The final aspect of benefit calculations is the optional sensitivity analysis. In the sensitivity analysis, the user sets a high and low range for each input parameter. The ranges are represented as a percentage of the primary parameter value (e.g., the high range may be set to 110% of the primary value and the low range may be set to 95% of the primary value). The benefit calculations are then performed using the high and low range of all inputs. Controlling the sensitivity range for each input allows the user to create customized scenarios that explore uncertainty (i.e., environmental regulation, market conditions, load growth, etc.).

---

[1] All SGCT inputs are consistent with the metrics that the DOE has requested from SGIG and SGD Recipients

[2] The benefits the project is expected to yield are determined by the tool based on user inputs.

[3] The user can choose to have the calculation of benefits end prior to this year but they cannot extend the analysis beyond this year.

2.5 Cost Calculations

The SGCT expresses cost estimates in terms of net present value (NPV). NPV is calculated from the project start date out to 2040. The user enters total project capital costs, along with the depreciation rate and interest rate into the tool. The tool then amortizes the costs over a user-specified period to determine a cost schedule. The user can also enter a customized cost schedule directly into the tool. The present value of the project cost is subtracted from the present value of the total benefits to determine a project's NPV.

Given the number of variations in accounting approaches and tax structures, it is difficult to develop a detailed and consistent cost modeling approach for all demonstrations and deployments. Therefore, the cost analysis is limited to this simple approach. However, it allows users to compare a high level approximation of a project's cost with the benefits that the project will yield. This high level comparison provides a context for interpreting the overall benefits and value of a project. For a detailed explanation of how costs are amortized and discounted over time, the reader should refer to Appendix

C.23 Cost Calculations.

3.0 Architecture and Design

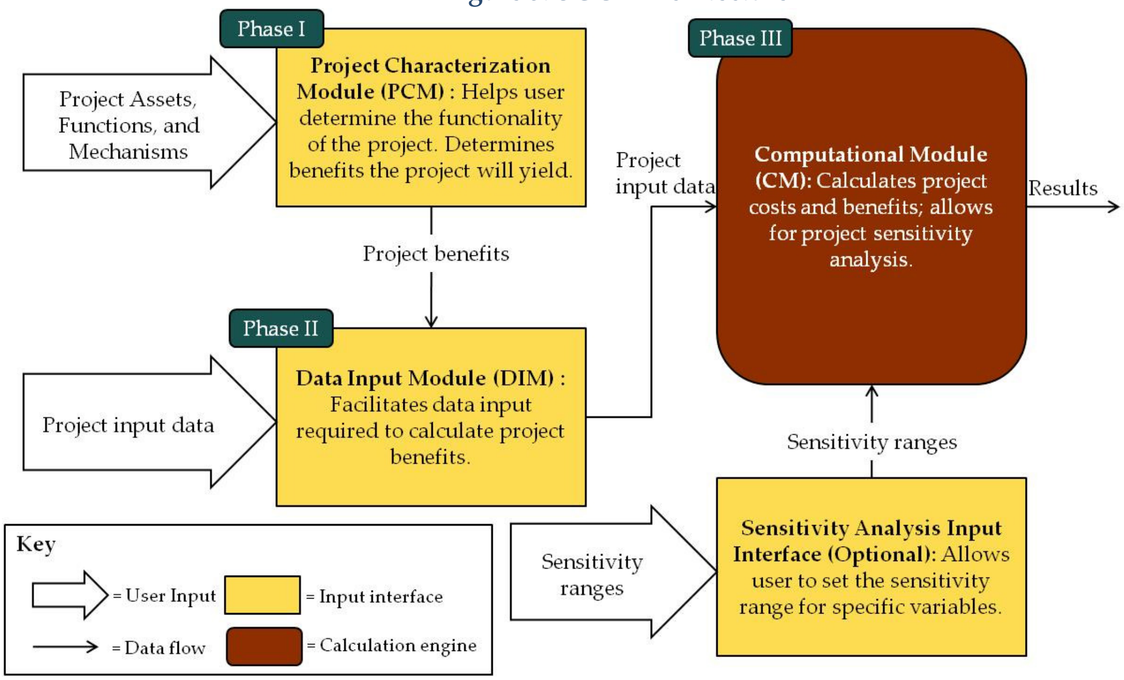
3.1 Design Principles

The SGCT is designed to be user-friendly, easy to understand, and flexible enough to enable the calculation of costs and benefits across a wide range of projects. The tool is intended for users with a basic understanding of smart grid technologies and terms. The assumptions and calculation methodologies are documented in Appendix C: Benefit and Cost Calculations. Because the smart grid is expected to grow in size and complexity, the tool is designed to be scalable so that it can evolve to meet the needs of the future. Future versions of the tool may include analytical framework updates to incorporate other smart grid systems, functions, or benefits.

3.2 Architecture

Figure 3 illustrates the overall architecture of the SGCT. Although the tool is contained in a single Excel™ file, it has three distinct phases. Phase I is the Project Characterization Module (PCM), Phase II is the Data Input Module (DIM), and Phase III is the Computational Module (CM).

Figure 3. SGCT Architecture



3.2.1 Project Characterization Module (PCM)

The Project Characterization Module identifies the benefits that the smart grid project could create, based on user-selected smart grid assets, functions, and mechanisms.

First, the user identifies the assets and technologies that will be installed as a result of the project. The PCM maps these assets to the functions they could potentially support. The user is then presented with a sub-set of possible functions and is prompted to specify which functionalities will be pursued by the project.

Next, the user is prompted to specify *how* each function will be achieved by specifying various mechanisms that will be realized for each function. A list of potential benefits is then presented to the user.

Finally, the PCM displays the function-benefit map for user verification before advancing to the next phase of the tool, the Data Input Module.

3.2.2 Data Input Module (DIM)

The Data Input Module facilitates the entry of required inputs. The required inputs are determined by the benefits identified by the PCM. That is, out of the dozens of inputs that are required to calculate all of the various smart grid benefits, the DIM prompts the user to enter only those inputs that are relevant to the benefits that a specific project enables.

For each required parameter, the user enters baseline data and annual project data for years in which the project is constructed and operational. While the model relies on project data as the primary source of inputs, certain inputs have built-in default values that a user can select if project-specific information is not readily available. These default values are based on published sources such as:

- EIA (Annual Energy Outlook 2009, Form 861, Form 411, etc.)
- Global Energy Decisions, Energy Velocity (FERC Form 714, etc.)
- SNL (FERC Form 1, etc.)
- Public filings, rate cases (PUC, FERC, ISO, etc.)]

At multiple points in the DIM, user inputs are checked for errors and completeness. If any errors or omissions in data entry are detected, a message will request the user to enter the correct values. The DIM will not allow the user to proceed to the next phase of the tool until all required data are entered correctly. Once all required data are entered, they are fed to the Computational Module (CM). Summaries of the final input data are presented to the user and the CM main interface is loaded.

3.2.3 Computational Module (CM)

The Computational Module is the calculation engine of the SGCT. The primary purpose of the CM is to transform the inputs from the DIM into the costs and benefits of the smart grid project being analyzed. The CM calculates costs and benefits on a yearly basis and presents summaries of these results to the user in tabular and graphical formats.

The CM uses escalation factors to project input values out to thirty years beyond the initial year of analysis. Depending on the inputs, different techniques and escalation factors are used to create forecasts. In general, escalation factors vary by region. Escalation factors include population growth, load growth, inflation, and energy price forecasts. In some cases, the default escalation factor is zero for years beyond the last year entered. All escalation factors can be reviewed and changed by the user at run time. For a detailed explanation of the forecasting methods used for each parameter in the SGCT, please see Appendix D.3 Input Escalation.

The CM includes a sensitivity analysis module. The user can set low and high sensitivity values to explore how benefits and costs of the smart grid project will be impacted by the uncertainty of input parameters. The results of the sensitivity analysis are presented in tabular and graphical formats.

4.0 Step-by-Step Instructions

4.1 Getting Started

The Smart Grid Computational Tool performs best when used with Excel™ 2007, but may also be used with Excel™ 2003. No additional programs or add-ins are required. In order to begin, go to the website **www.smartgrid.gov**. Download the Excel™ file named "US DOE Smart Grid Computational Tool DOE Version 2.0.xlsm" to your computer and open the file.

Please ensure that your Excel™ settings allow for macros to run or the tool will not work properly. The tool has been carefully designed and password protected in order to ensure the fidelity of the macros.

Once the file is downloaded, it can be used as the template for all future analyses. To start a new analysis, open the downloaded version and save the file as a new, uniquely named version on your computer. This will save time otherwise spent downloading the SGCT file from www.smartgrid.gov.

When you open the SGCT, you will see the "Start" tab, pictured in Figure 4. The Start tab provides a brief introduction to the SGCT, explains the purpose and output of the tool, and reviews the general architecture and methodology of the tool. This tab also includes contact information for submitting questions or comments on the tool. The most prominent feature of this tab is the blue "Click here" button. Clicking this button will initiate a new analysis by launching the PCM.

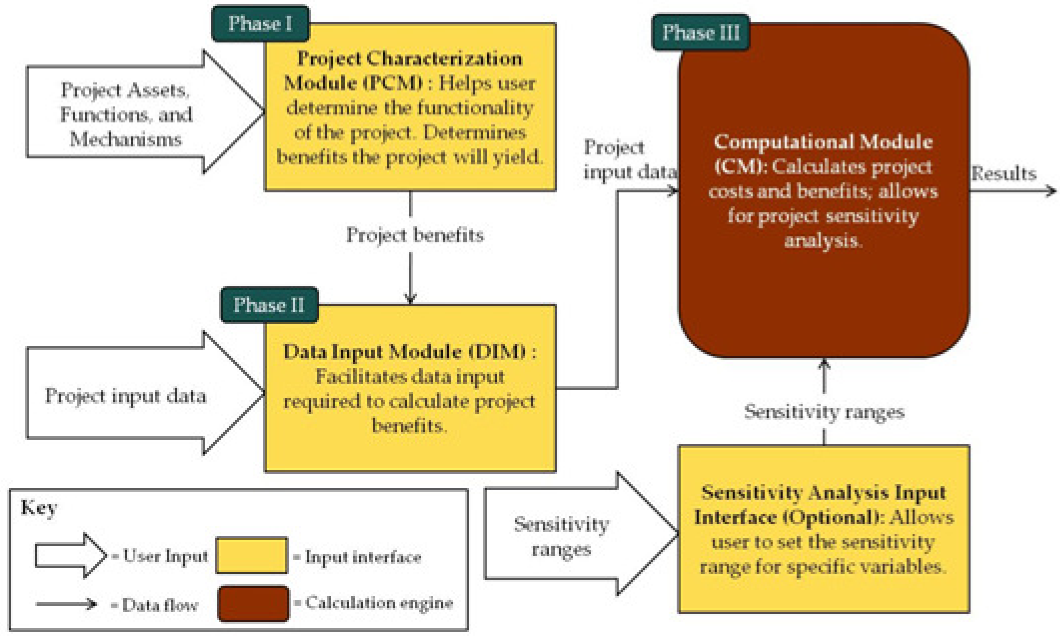
Figure 4. The SGCT "Start" tab

U.S. Department of Energy Smart Grid Computational Tool (SGCT)

Purpose of Tool: SGCT can be used to calculate the benefits of smart grid projects, compare costs and benefits, and gain a clearer understanding of the value of smart grid technology and systems in terms of monetary benefit. Furthermore, the SGCT can be used to analyze how the costs and benefits vary given different scenarios and assumptions. Finally, the analysis and insight provided by the SGCT can be leveraged to inform future smart grid investment.

Explanation of Output: The output of the SGCT consists of charts, graphs and tables that summarize 22 distinct benefits of smart grid technology deployment. The benefits are monetized and calculated from actual or estimated metrics collected in the first five years of a project lifetime. Based on the first five years of data benefits can be projected out to 2040. The output also includes charts, graphs and tables that summarize the results of a sensitivity analysis. The user is able to set a high and low sensitivity range for each input in the tool and the output shows how the benefits are affected by variability of the inputs.

Directions: This tool was created to be extremely user-friendly and easy to navigate. However, it may be useful to review the overall methodology of the tool before beginning a new analysis. Below is a diagram of the tool architecture that summarizes the analysis methodology. The tool is divided into three distinct phases: the Initial Project Setup Module (IPSM), the Project Data Input Module (PDIM), and the Master Computational Tool (MCT). The first phase, or IPSM, collects information about the project such as the types of assets being installed, the functionality of those assets, and how the functionality will be used (the mechanisms). From this input the IPSM determines the list benefits that the project could yield. These potential project benefits are then fed into the second phase of the tool, the PDIM. The PDIM uses the list of benefits to determine the inputs required to calculate the benefits. The PDIM then helps navigate the user through the process of entering the required data. Its main purpose is to ensure that all the required data is entered in the proper format so that the benefits can be analyzed successfully. The input data is then fed into the final phase, the MCT. The MCT is the calculation engine of the tool, it crunches the numbers and generates the output. The MCT also allows the user to complete a sensitivity analysis if desired.
Using the tool is as easy as clicking the big blue button below to begin and then following the directions that appear in each phase of the tool. The user can refer to the official User Guide for the U.S. Department of Energy Smart Grid Computational Tool for detailed directions and information about the calculation methodologies and assumptions used in the tool.



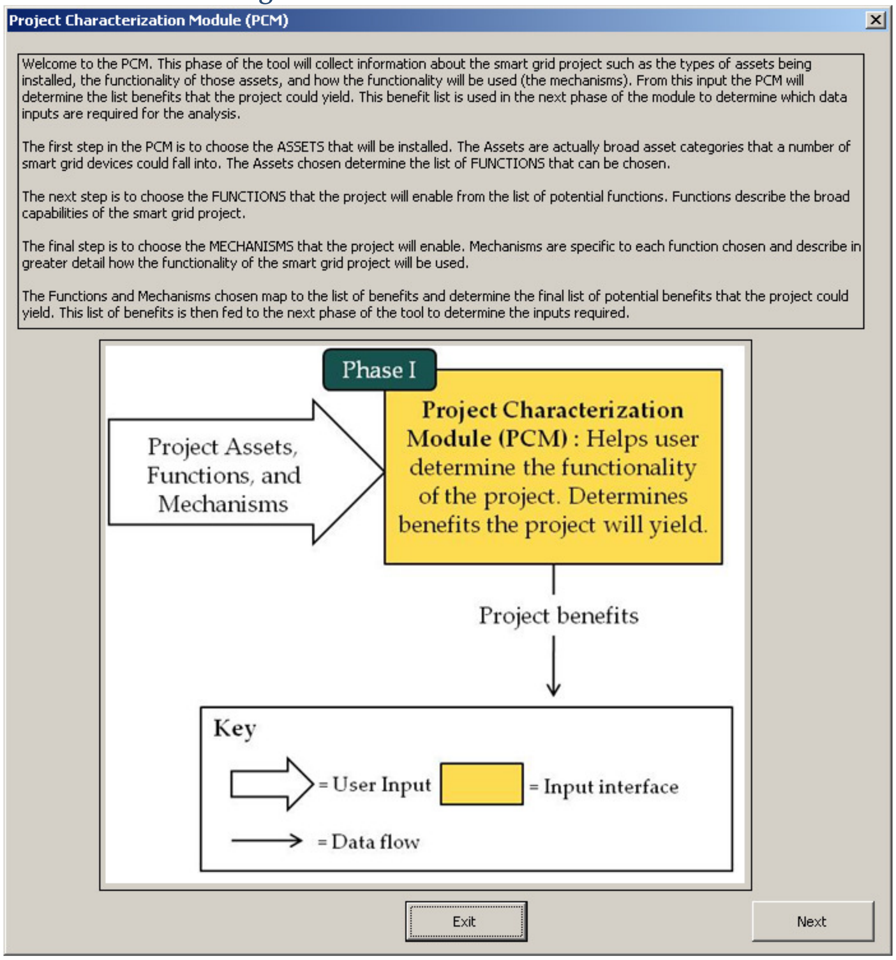
Click here to begin the SGCT

4.2 Creating a New Analysis

4.2.1 Project Characterization Module (PCM)

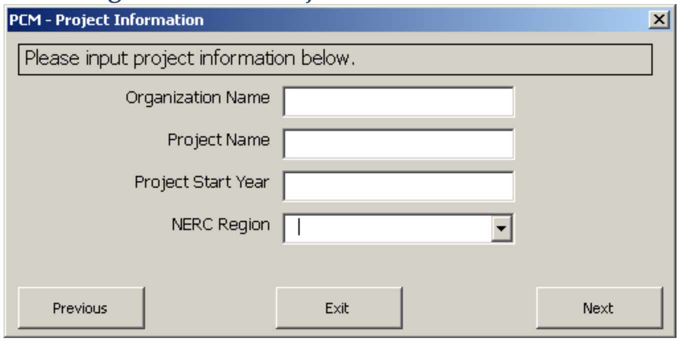
The first PCM screen, depicted in Figure 5, provides a brief overview of the PCM phase of the SGCT. Reading this screen will greatly enhance the user's understanding of the PCM steps to follow and is strongly recommended. Click "Next" to advance.

Figure 5. PCM Introduction Screen



The second PCM screen, depicted in Figure 6 collects general information about the smart grid project.

Figure 6. PCM Project Information Screen



The four user inputs on this screen are:

» **Organization Name –** Enter the name of the utility or organization that will be implementing the smart grid project.

» **Project Name** – Enter the unique smart grid project unique name, if any.

» **Project Start Year –** Enter the first year that the smart grid project began to operate. This year will be the first year that cost and benefits are calculated. Entries should be in 20XX format.

» **NERC Region –** Select the North American Electric Reliability Corporation (NERC) region where the smart grid project is going to be implemented from the drop-down list as shown in Table 4. This parameter is necessary to enable the SGCT to set the correct escalation factors and provide the user with the correct optional default input data. If the project spans NERC regions or is not associated with a NERC region, select the most representative or closest NERC region.

Table 4. NERC Regions

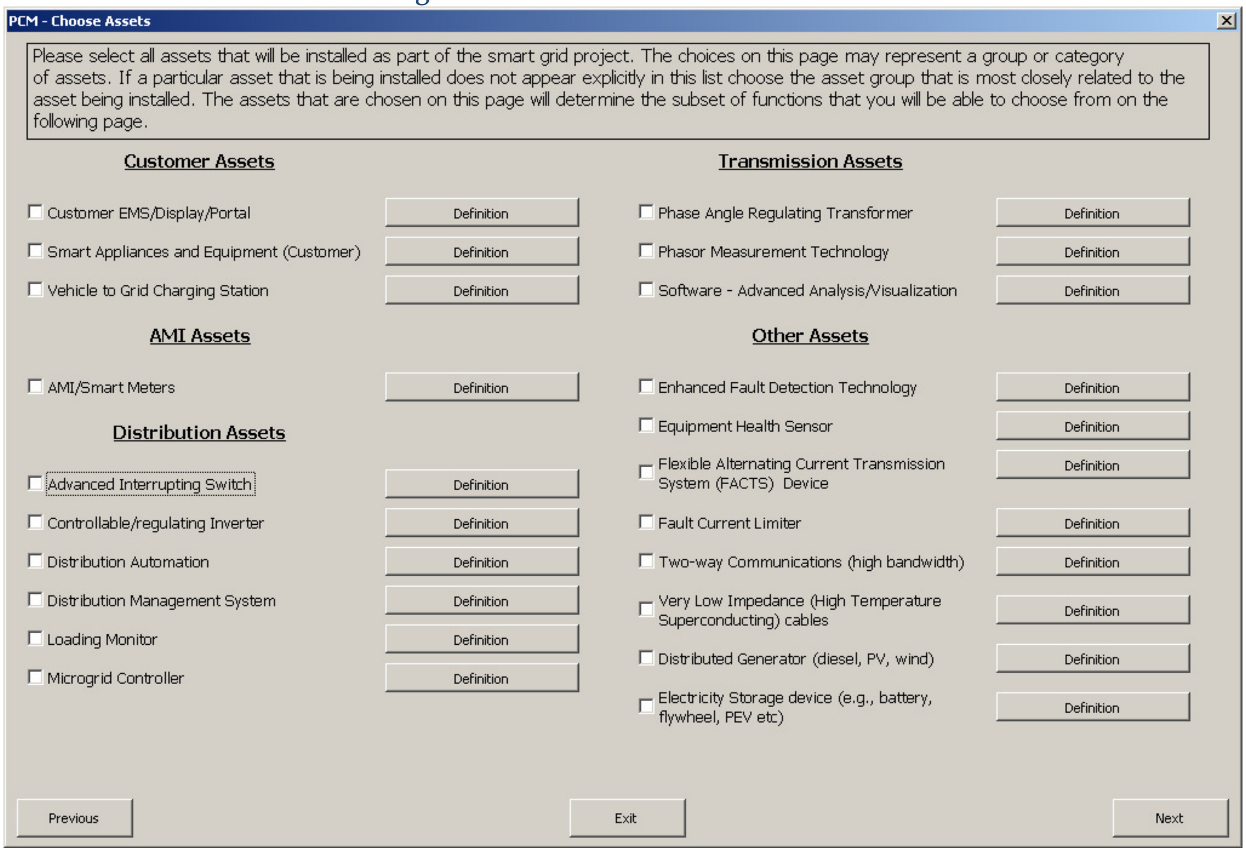
NERC Region Abbreviation	NERC Region Name
FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
TRE	Texas Regional Entity
WECC	Western Electricity Coordinating Council

Once you have entered the project information into the PCM Project Information screen, click “Next” to advance.

At any point, you may end the PCM session by clicking the “Exit” button at the bottom of any screen. Any data entered up to that point will be discarded.

The next PCM screen, depicted in Figure 7, is used to specify the types of assets that will be installed as part of the smart grid project. The assets are presented in five broad categories. (For a detailed explanation of each asset please see Section 2.2 Relationships of Assets to Functions.) In order to select an asset, simply click the check box next to the asset name. Once all of the appropriate assets have been selected, click the "Next" button to proceed to the next screen.

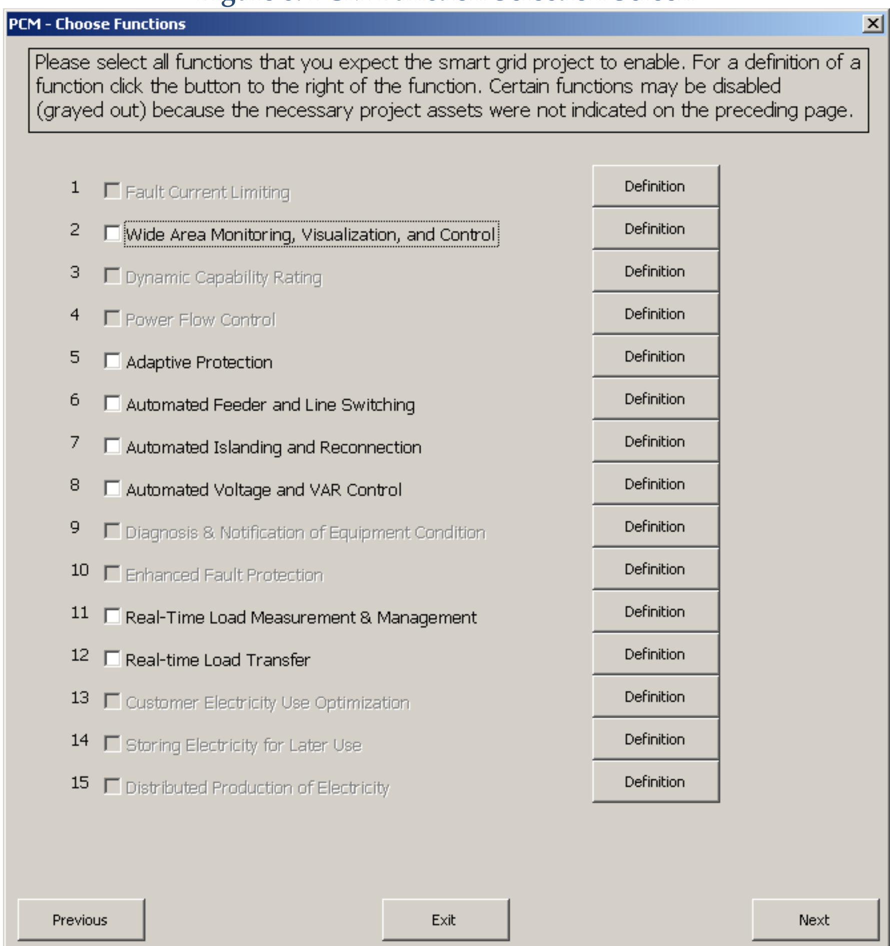
Figure 7. PCM Asset Selection Screen



The next input screen, depicted in Figure 8, is the PCM Function Selection Screen. In this screen, the user identifies the specific functionality that the smart grid project will support. The SGCT defines 15 unique functions that a smart grid might enable. Each of these functionalities is associated with certain assets and can lead to various benefits. Because each function requires specific assets in order to be enabled, some of the functionalities in the list on the PCM Function Selection Screen are grayed out and disabled if the associated assets were not selected on the previous screen.

You must specify which functions, of those enabled on the screen, the project will support. This is done by clicking the check box next to the appropriate function. To view the definition of a function, click the appropriate “Definition” button. The definition feature helps you determine if the functionality will be enabled by the smart grid project. If you feel that a function is omitted, use the “Previous” button to navigate back to the PCM Asset Selection Screen to ensure that all of the appropriate assets are indicated. When all supported functions have been selected, click the “Next” button.

Figure 8. PCM Function Selection Screen



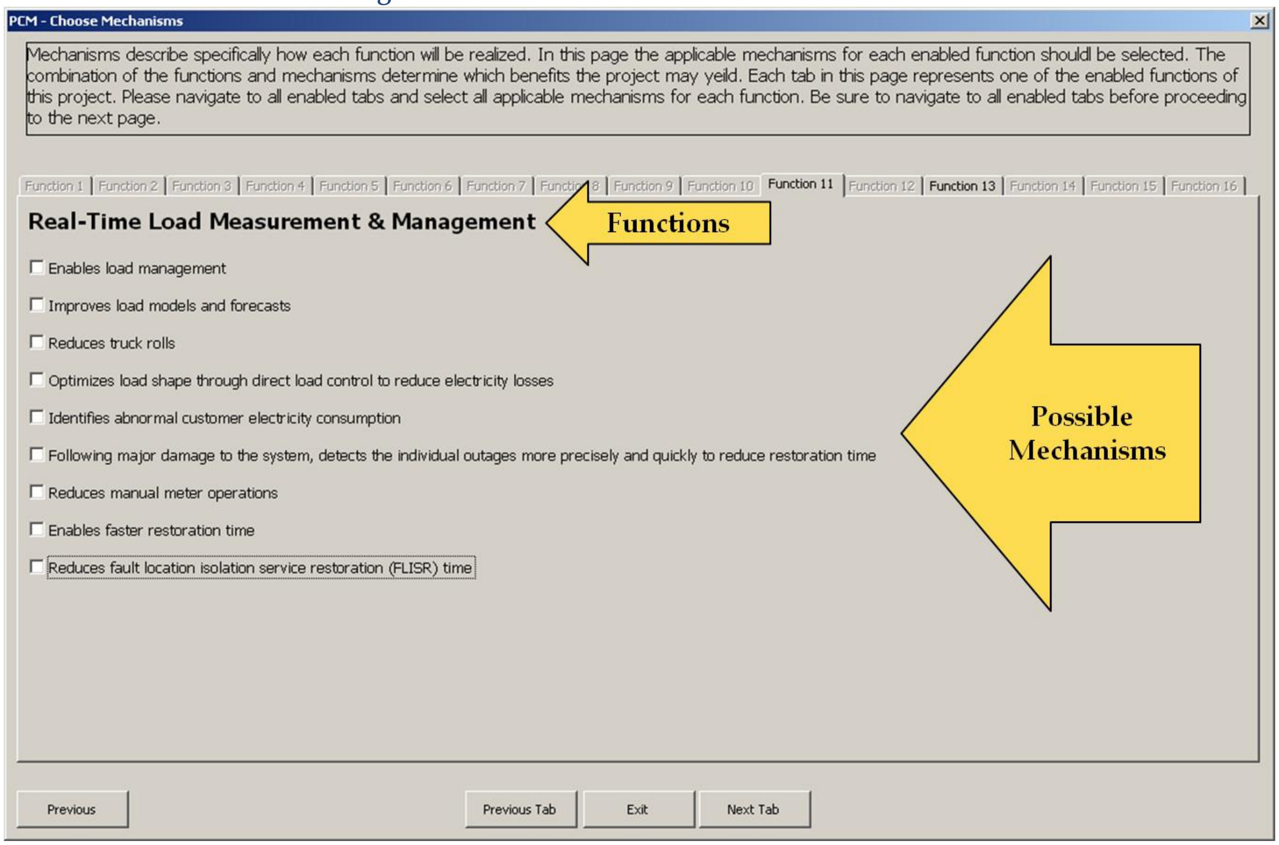
Use the PCM Mechanism Selection Screen, depicted in Figure 9, to further specify how the smart grid functions will be realized by indicating which mechanisms will likely be achieved.

Functions are very broad descriptions of how smart grid will impact the electricity system. Mechanisms describe the specific actions or results that a project with certain functionality will pursue. This screen allows you to specify the *mechanisms* that describe how you plan to utilize the smart grid.

The PCM Mechanism Selection Screen has a tabbed interface.

Each tab in this screen corresponds to a specific function. Under each tab is a list of possible mechanisms that is specific to that particular function. Only tabs that represent functions you specified on the Function Selection Screen are accessible in the Mechanism Selection Screen. All other tabs are grayed out and cannot be navigated to. Click on each active tab and complete the entries within from the list of check boxes. In order to indicate that a mechanism will be supported, click the appropriate checkbox.

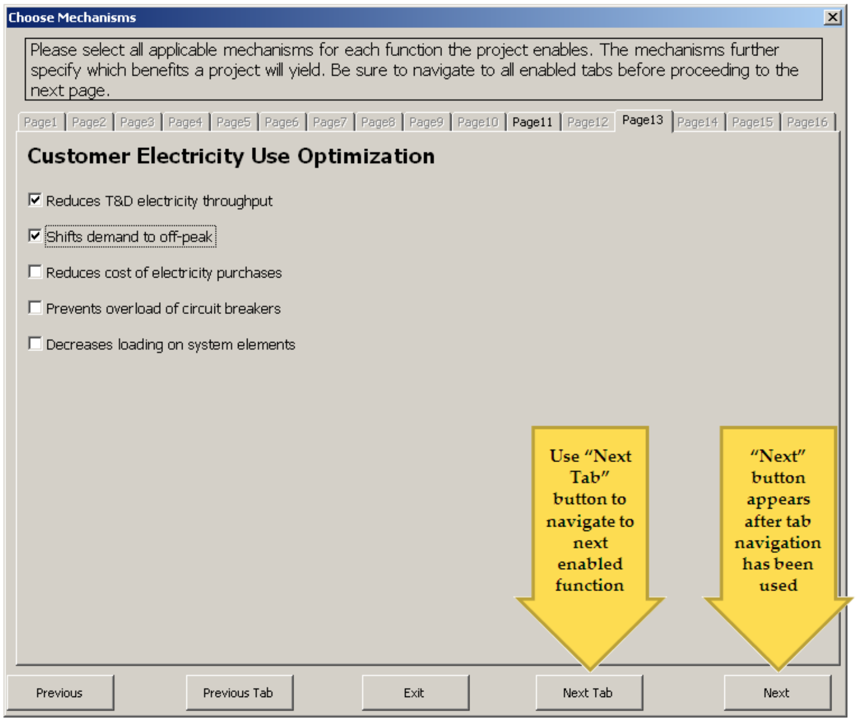
Figure 9. PCM Mechanism Selection Screen



It is important to note that the mechanisms listed on each enabled tab represent all possible mechanisms that could be supported; however, not every mechanism is necessarily supported for the particular smart grid function you selected. You must carefully select the appropriate mechanisms for the project in question.This requires that you think about *how* a function will be realized. A review of Appendix B: Function to Benefit Rationale will help you understand the ways in which the functions lead to various benefits. This understanding will help you select the appropriate mechanism.

Once the supported mechanisms have been selected for a function, click the "Next Tab" button as highlighted in Figure 10 to navigate to the next enabled tab. To return to a previous tab, click the "Previous Tab" button. It is important to navigate to all enabled tabs and select the appropriate mechanisms before navigating to the next screen. In order to ensure that you see all additional tabs, the "Next" button (which will navigate to the next screen) does not appear until the "Next Tab" button is clicked. The purpose of this enforcement is to ensure that you realize that there are additional tabs on this page; therefore, it is important that you still click the "Next Tab" button to visit all relevant tabs before clicking the "Next" button.

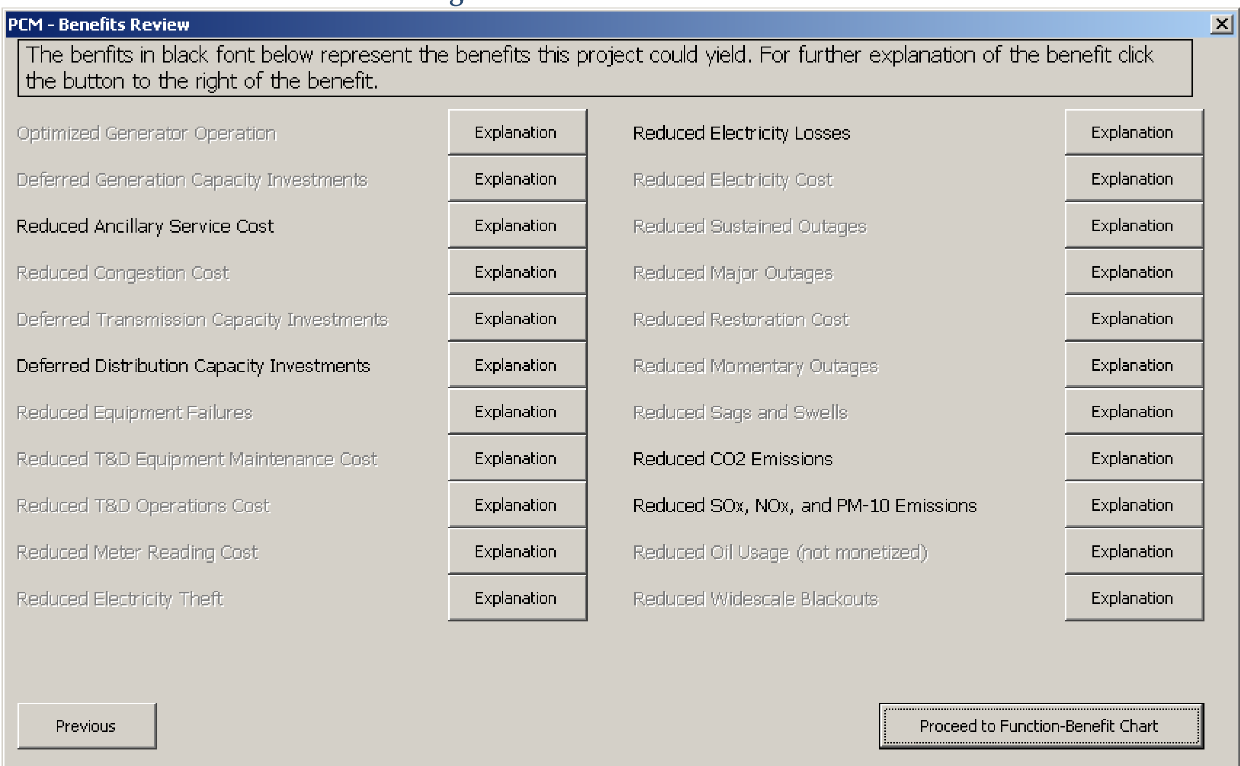
Figure 10. PCM Mechanism Selection Screen Navigation



When all of the applicable mechanisms have been selected, click the "Next" button to proceed to the next screen. The PCM then processes the inputs. This process takes about 20 seconds.

After the PCM processes the inputs, the SCGT selects the benefits that the smart grid project should yield, given the assets, functions, and mechanisms you have selected. The PCM Benefits Screen (depicted in Figure 11) displays these benefits. An explanation of each benefit can be reviewed by clicking the “Explanation” buttons.

Figure 11. PCM Benefits Screen



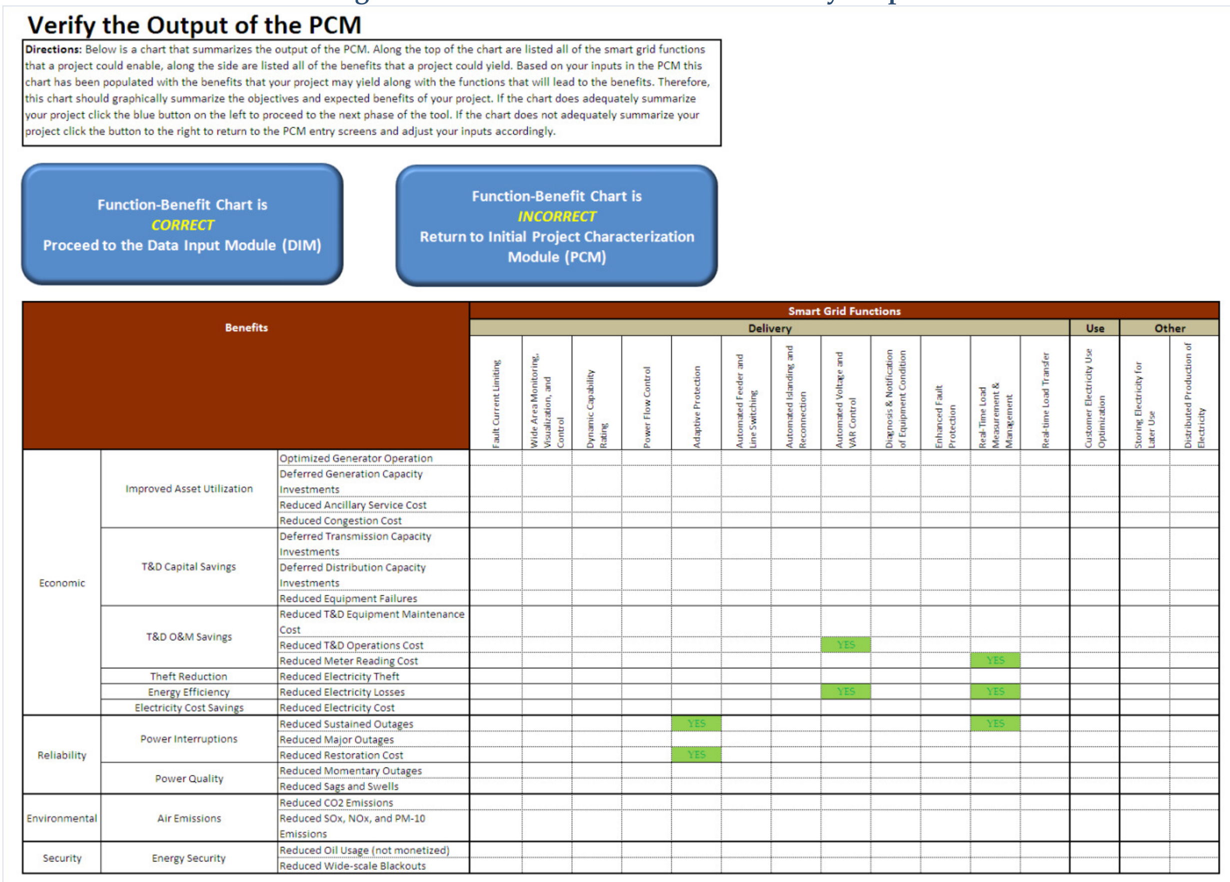
Carefully review the benefits the SGCT has selected. In the next phase of the SGCT, the DIM, you will enter the inputs required to quantify the benefits shown in black. If you are not satisfied with the benefits list, use the “Previous” buttons to navigate back through the preceding PCM screens to alter your selections.

Once you are satisfied with the benefits listed on the PCM Benefits Screen, click the “Proceed to Function-Benefit Chart” button to complete the Project Characterization Module.

You are now prompted to save the file, which is recommended. You have entered all of the PCM inputs. Saving the file allows you to close Excel™ and retain a copy of the tool that is unique to the project under analysis. This enables you to resume your analysis from this point rather that starting from scratch, while also retaining a copy of the blank SGCT on your computer for additional analyses.

After the save prompt, an Excel™ tab called “Function-Benefit Chart”, which is depicted in Figure 12, should be visible. This tab shows the user a Function-Benefit summary map that is specific to the project under analysis. This map allows you to see a summary of how the functions of the project map to the benefits. This information provides deeper insight into how benefits and functions are linked. This tab also serves as a last visual check before moving into the Data Input Module phase of the SGCT. If the highlighted functions or benefits in the chart fail to accurately represent your project, you can click the button at the top that reads “Function-Benefit Chart is INCORRECT”. This will return you to the first screen of the PCM so you can review all inputs by revisiting each screen in sequence. All of the previously entered data will still be preserved so you can review them and not waste time having to re-enter information that is correct.

Figure 12. The Function-Benefit Summary Map



Verify the Output of the PCM

Directions: Below is a chart that summarizes the output of the PCM. Along the top of the chart are listed all of the smart grid functions that a project could enable, along the side are listed all of the benefits that a project could yield. Based on your inputs in the PCM this chart has been populated with the benefits that your project may yield along with the functions that will lead to the benefits. Therefore, this chart should graphically summarize the objectives and expected benefits of your project. If the chart does adequately summarize your project click the blue button on the left to proceed to the next phase of the tool. If the chart does not adequately summarize your project click the button to the right to return to the PCM entry screens and adjust your inputs accordingly.

Function-Benefit Chart is CORRECT Proceed to the Data Input Module (DIM)

Function-Benefit Chart is INCORRECT Return to Initial Project Characterization Module (PCM)

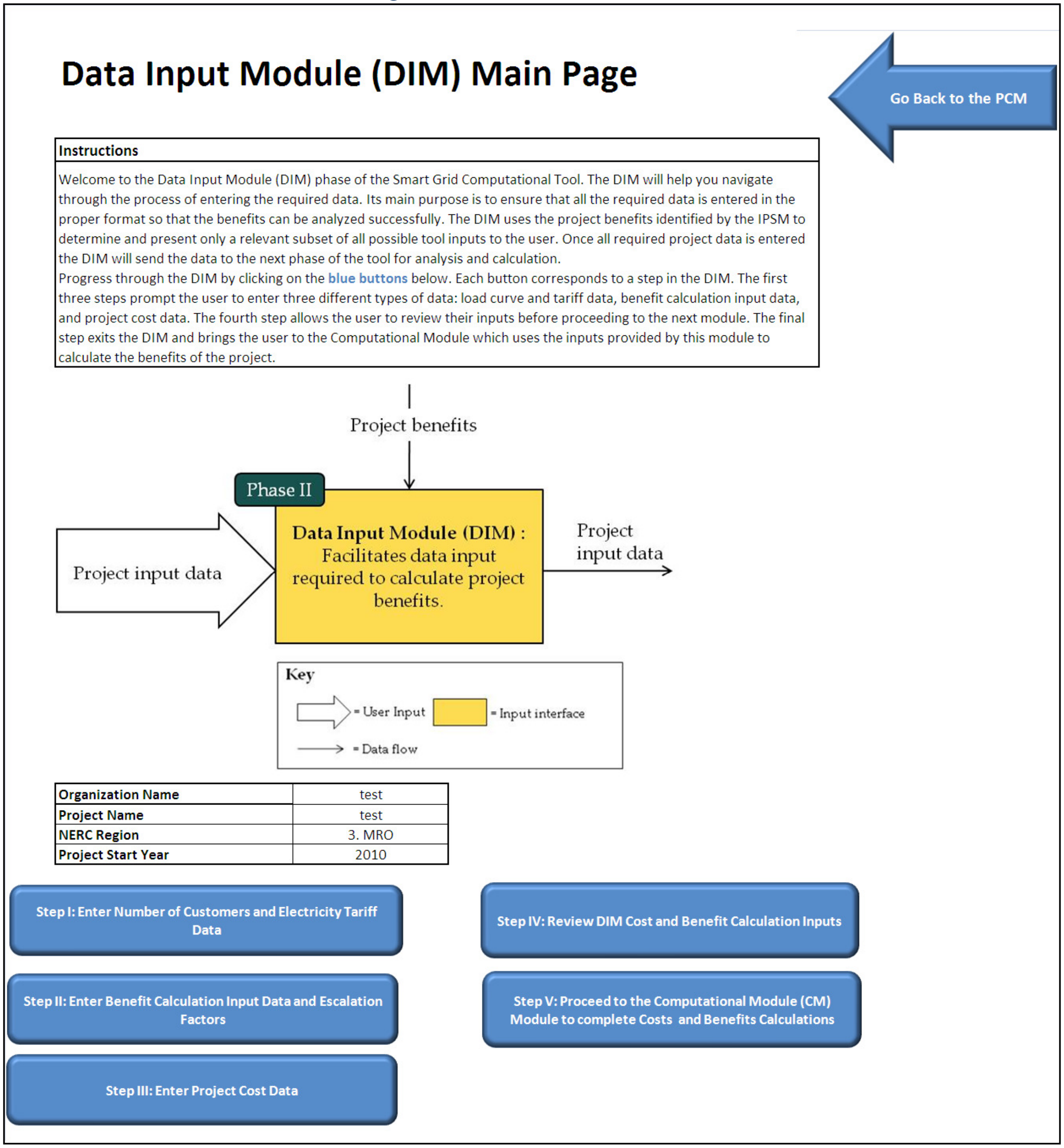
Benefits			Smart Grid Functions														
			Delivery												Use	Other	
			Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Power Flow Control	Adaptive Protection	Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
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 T&D Equipment Maintenance Cost															
		Reduced T&D Operations Cost								YES							
		Reduced Meter Reading Cost											YES				
	Theft Reduction	Reduced Electricity Theft															
	Energy Efficiency	Reduced Electricity Losses								YES			YES				
	Electricity Cost Savings	Reduced Electricity Cost															
Reliability	Power Interruptions	Reduced Sustained Outages					YES						YES				
		Reduced Major Outages															
		Reduced Restoration Cost					YES										
	Power Quality	Reduced Momentary Outages															
		Reduced Sags and Swells															
Environmental	Air Emissions	Reduced CO2 Emissions															
		Reduced SOx, NOx, and PM-10 Emissions															
Security	Energy Security	Reduced Oil Usage (not monetized)															
		Reduced Wide-scale Blackouts															

If the chart accurately represents the project under analysis, click the button "Function-Benefit Chart is CORRECT". This will end the PCM phase, and bring you to the "MAIN" tab which is the first and primary tab of the DIM phase.

4.2.2 Data Input Module (DIM)

The “MAIN” page is the home screen of the DIM, and lists each step in the phase. After you complete each step, the DIM returns to the Main page. The Main page is depicted in Figure 13.

Figure 13. Main tab of the DIM



The MAIN screen contains the following features, listed from top to bottom:

- **Go Back to the PCM –** This arrow-shaped button is used to exit the DIM and return to the PCM.
- **Instructions –** A general explanation on how to progress through the DIM.

- **Tool Diagram: DIM phase –** A graphical representation of where the user is within the SGCT process.

- **Project Information Table –** A summary table of the project information. If this information is not correct, return to the PCM and correctly enter the required information.

- **DIM Step Buttons –** Navigation buttons that take you to the various steps of the DIM. Clicking on a button will take you to a data input page, to an input review page, or to the next phase of the SGCT.

DIM Step I

After confirming that the information in the Project Information Table is correct, click the "Step I" button.

In DIM Step I, you enter electricity tariff data and customer population data. This data entry is required regardless of which benefits were enabled by the PCM because it used in many of the benefit calculations.

Once the "Step I" button is clicked the "Population and Tariff Entry" page will appear. This page contains two main data entry tables which are depicted in Figure 14. The two tables are the Electricity Rates by Customer Class and the Number of Customers by Class tables, or Table 1 and 2 respectively.

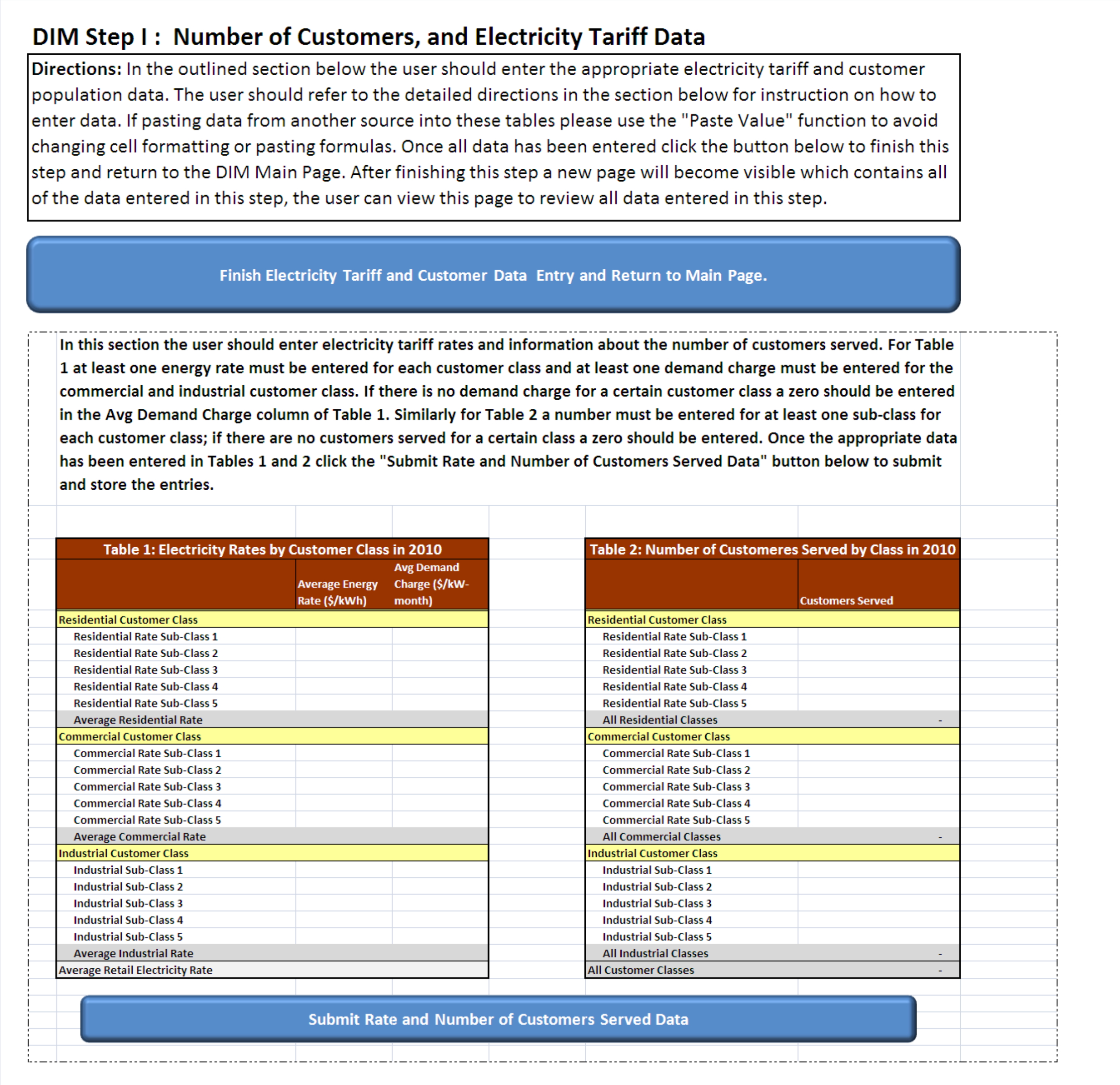
Table 1 is where you enter up to five different electricity tariffs (energy rate and/or demand charge) for each of three customer classes (residential, commercial, and industrial). At least one electricity rate must be entered for each customer class.

Table 2 is where you enter the number of customers served within each customer sub-class. At least one value is required for each customer class.

In both of these tables, data should reflect the values in the initial project year and should only be entered into the blank, white cells; grey cells are populated automatically. If you are pasting data from another spreadsheet or source into the tables, use the "Paste Values" function to avoid pasting formulas or changing the formatting of the cells.

Once tariff and customer population data have been properly entered, click the "Submit Rate and Number of Customers Served Data" button to submit the data to the DIM. If the data are input correctly, a message stating "Electricity tariff and customers served data have been successfully submitted" is displayed. Otherwise, a message explaining what required data are missing will be displayed.

Figure 14. Electricity Tariff Data and Customers Served Data Entry Tables


DIM Step I : Number of Customers, and Electricity Tariff Data

Directions: In the outlined section below the user should enter the appropriate electricity tariff and customer population data. The user should refer to the detailed directions in the section below for instruction on how to enter data. If pasting data from another source into these tables please use the "Paste Value" function to avoid changing cell formatting or pasting formulas. Once all data has been entered click the button below to finish this step and return to the DIM Main Page. After finishing this step a new page will become visible which contains all of the data entered in this step, the user can view this page to review all data entered in this step.

Finish Electricity Tariff and Customer Data Entry and Return to Main Page.

In this section the user should enter electricity tariff rates and information about the number of customers served. For Table 1 at least one energy rate must be entered for each customer class and at least one demand charge must be entered for the commercial and industrial customer class. If there is no demand charge for a certain customer class a zero should be entered in the Avg Demand Charge column of Table 1. Similarly for Table 2 a number must be entered for at least one sub-class for each customer class; if there are no customers served for a certain class a zero should be entered. Once the appropriate data has been entered in Tables 1 and 2 click the "Submit Rate and Number of Customers Served Data" button below to submit and store the entries.

Table 1: Electricity Rates by Customer Class in 2010	Average Energy Rate ($/kWh)	Avg Demand Charge ($/kW-month)
Residential Customer Class		
Residential Rate Sub-Class 1		
Residential Rate Sub-Class 2		
Residential Rate Sub-Class 3		
Residential Rate Sub-Class 4		
Residential Rate Sub-Class 5		
Average Residential Rate		
Commercial Customer Class		
Commercial Rate Sub-Class 1		
Commercial Rate Sub-Class 2		
Commercial Rate Sub-Class 3		
Commercial Rate Sub-Class 4		
Commercial Rate Sub-Class 5		
Average Commercial Rate		
Industrial Customer Class		
Industrial Sub-Class 1		
Industrial Sub-Class 2		
Industrial Sub-Class 3		
Industrial Sub-Class 4		
Industrial Sub-Class 5		
Average Industrial Rate		
Average Retail Electricity Rate		

Table 2: Number of Customeres Served by Class in 2010	Customers Served
Residential Customer Class	
Residential Rate Sub-Class 1	
Residential Rate Sub-Class 2	
Residential Rate Sub-Class 3	
Residential Rate Sub-Class 4	
Residential Rate Sub-Class 5	
All Residential Classes	-
Commercial Customer Class	
Commercial Rate Sub-Class 1	
Commercial Rate Sub-Class 2	
Commercial Rate Sub-Class 3	
Commercial Rate Sub-Class 4	
Commercial Rate Sub-Class 5	
All Commercial Classes	-
Industrial Customer Class	
Industrial Sub-Class 1	
Industrial Sub-Class 2	
Industrial Sub-Class 3	
Industrial Sub-Class 4	
Industrial Sub-Class 5	
All Industrial Classes	-
All Customer Classes	-

Submit Rate and Number of Customers Served Data

Once all electricity tariff and customer population data have been successfully submitted, click the large "Finish" button at the top of the page to return to the Main page and begin Step II.

The DIM will perform a final check to ensure all required data were submitted successfully. If all required data have been successfully entered, the DIM will bring you to the "MAIN" page. Otherwise, you will remain at the Step I screen and a message will appear indicating the missing data.

Upon completing Step I, the "Population and Tariff Review" page is displayed. This page contains the tariff and customer population data submitted to the DIM. The user cannot alter any of the data on this page but can review them for accuracy before proceeding to Step II.

DIM Step II

To proceed to Step II of the DIM, click the "Step II" button on the Main page. In Step II, you enter the baseline and project data required to calculate benefits of the particular smart grid project under analysis. Enter only data that will be used in benefit calculations relevant to the project. Clicking the "Step II" button takes you to the "Data Input Sheet" page, which is depicted in Figure 15 and Figure 16.

At the top of the Data Input Sheet page are the directions and three buttons that explain important concepts and features of this DIM step. Two of these buttons show you an explanation of the optional inputs and default data features. These features are also explained in the user guide below.

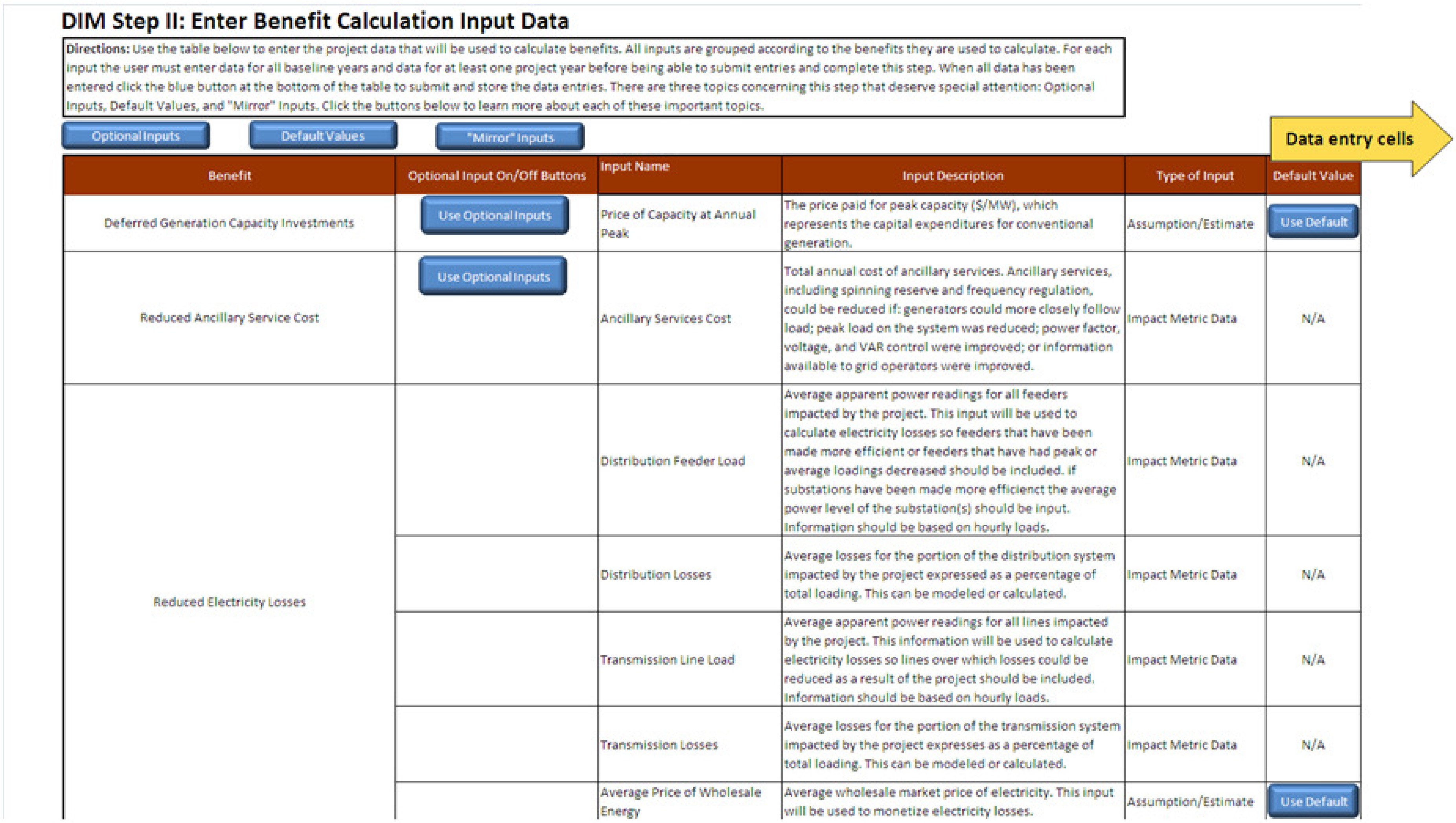
The third button shows an explanation of the **"Mirror" Inputs concept**, which is also described here. Many DIM inputs can be tracked in terms of avoided costs or activities as a result of the project rather than in absolute terms. For example, instead of tracking Meter Operations Costs, it might be easier for a project to track Avoided Meter Operations Costs as a result of AMI implementation. Conversely, other inputs that are framed as costs and activities avoided could be tracked in absolute terms (e.g. Number of Truck Rolls instead of Truck Rolls Avoided). Inputs that are reframed in this way are termed "mirror" inputs. Because the calculation methodology of this tool is concerned with the delta between project and baseline data, a user can enter a mirror input for any input.

If mirror inputs are used, it is important that 1) you also reframe the baseline data in the same way as the project data and 2) all entries (both baseline and project) are entered as negative numbers.

The data input table depicted in Figure 15 and Figure 16 actually appears as one, continuous, large table in the DIM; its two main sections are displayed separately in this user guide. The first section, the Data Input Sheet in Figure 15, contains all of the explanatory information about the inputs. It also contains buttons that allow you to enter optional inputs and use default values. The second section contains the Data Entry Cells, depicted in Figure 16, which are used to enter the values for each input.

The first column in the data input sheet, the "Benefit" column, lists the benefit(s) that the inputs will be used to calculate. The second column, the "Optional Input On/Off Buttons" column, contains buttons that appear if alternative inputs are available for a given benefit. These buttons, labeled "Use Optional Inputs", give users the option to enter alternative inputs that may be more convenient than the standard form. These alternative inputs are generally more detailed and granular in nature. If a button does not appear beside the benefit, then only the standard inputs are acceptable. Upon clicking an optional input button, the standard data entry rows will be blacked out and disabled and alternative data entry rows will appear. Any data that were entered into the standard input rows will be cleared if the alternative inputs are used. Similarly, if the optional input button is clicked again, the optional input rows disappear and the standard input rows are enabled, ready for input. Any data that were entered into the optional input rows will be cleared after this action.

Figure 15. Data Input Sheet



DIM Step II: Enter Benefit Calculation Input Data

Directions: Use the table below to enter the project data that will be used to calculate benefits. All inputs are grouped according to the benefits they are used to calculate. For each input the user must enter data for all baseline years and data for at least one project year before being able to submit entries and complete this step. When all data has been entered click the blue button at the bottom of the table to submit and store the data entries. There are three topics concerning this step that deserve special attention: Optional Inputs, Default Values, and "Mirror" Inputs. Click the buttons below to learn more about each of these important topics.

Optional Inputs | Default Values | "Mirror" Inputs

Data entry cells

Benefit	Optional Input On/Off Buttons	Input Name	Input Description	Type of Input	Default Value
Deferred Generation Capacity Investments	Use Optional Inputs	Price of Capacity at Annual Peak	The price paid for peak capacity ($/MW), which represents the capital expenditures for conventional generation.	Assumption/Estimate	Use Default
Reduced Ancillary Service Cost	Use Optional Inputs	Ancillary Services Cost	Total annual cost of ancillary services. Ancillary services, including spinning reserve and frequency regulation, could be reduced if: generators could more closely follow load; peak load on the system was reduced; power factor, voltage, and VAR control were improved; or information available to grid operators were improved.	Impact Metric Data	N/A
Reduced Electricity Losses		Distribution Feeder Load	Average apparent power readings for all feeders impacted by the project. This input will be used to calculate electricity losses so feeders that have been made more efficient or feeders that have had peak or average loadings decreased should be included. If substations have been made more efficienct the average power level of the substation(s) should be input. Information should be based on hourly loads.	Impact Metric Data	N/A
		Distribution Losses	Average losses for the portion of the distribution system impacted by the project expressed as a percentage of total loading. This can be modeled or calculated.	Impact Metric Data	N/A
		Transmission Line Load	Average apparent power readings for all lines impacted by the project. This information will be used to calculate electricity losses so lines over which losses could be reduced as a result of the project should be included. Information should be based on hourly loads.	Impact Metric Data	N/A
		Transmission Losses	Average losses for the portion of the transmission system impacted by the project expresses as a percentage of total loading. This can be modeled or calculated.	Impact Metric Data	N/A
		Average Price of Wholesale Energy	Average wholesale market price of electricity. This input will be used to monetize electricity losses.	Assumption/Estimate	Use Default

Figure 16. Data Input Sheet Data Entry Cells

Unit						Project				
	Baseline 2010	Baseline 2011	Baseline 2012	Baseline 2013	Baseline 2014	2010	2011	2012	2013	2014
$/MW	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00
$	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1				
MVA	100.00	100.00	100.00	100.00	100.00	90.00				
%	3%	3%	3%	3%	3%	3%				
MVA	-	-	-	-	-	-				

Additional input cells

The next three columns in Figure 15 are "Input Name" and "Input Description," followed by the "Type of Input" column. The entries in the Type of Input column are either "Impact Metric Data" or "Assumption/Estimate." An input row labeled as "Impact Metric Data" indicates that the data in that row must be carefully estimated or directly measured by the user because the values of those data are directly impacted by the functionality of the smart grid project under analysis. An input row labeled as "Assumption/Estimate" indicates that the data in that row can be roughly assumed or estimated by the user because the value of the data is not directly impacted by the smart grid project. Examples of data of this type include the average fuel efficiency of service vehicles and the value of CO_2 emissions.

In some cases, there are default values for "Assumption/Estimate" data. You can review all of the default values in the SGCT by navigating to the "Default Summary" page. In general, default values vary by NERC region and year. If default values are available for a particular input, there will be a "Use Default" button in the input row in the column labeled "Default Value." Clicking this button will populate that input row with the default values. Please note that this results in the population of five years of baseline and project data.If the project being analyzed has less than five years of project data, extra default values should be deleted.

The data entry cells, depicted in Figure 16, are used to enter the values for each input. There are two types of values that are required for any input: "Baseline" values and "Project" values. The baseline data for these inputs should represent forecasted, calculated, or estimated data for a particular year under some baseline scenario[4]. Project data should represent actual measured data for each year available. For each input, you must enter data for every baseline year and at least one project year.

Once all required data are entered, click the large blue button at the bottom of the page to submit the data and move on to the next step. The DIM will perform a final check to ensure all required data were submitted successfully. If all required data haven't been successfully entered, a message explaining which data are still required will be displayed. To avoid errors, ensure all required data are entered before proceeding.

After successfully submitting the benefit input data, the Escalation Factor Table page appears, as shown in Figure 17. This table allows you to review and set escalation factors.

[4] Typically the baseline scenario most appropriate will be the "no build" scenario. See Section 2.4 Benefit Calculations and Appendix D.1 The Baseline Concept, for detailed explanations.

Figure 17. Escalation Factor Table

Step II: Enter Benefit Calculation Input Data, Escalation Factors

Directions: The Smart Grid Computational Tool can calculate costs and benefits of the smart grid project out to the year 2040. In order to complete this analysis escaltion factors are applied to the inputs that have been entered. On this page the user can choose to use default escalation factors or they can enter their own escalation factors in the "Value" column. If pasting data from another source into this table please use the "Paste Value" function to avoid changing cell formatting or pasting formulas. To view a list of inputs affected by an escalation factor click the blue buttons in the "Inputs Affected" column. Additionally, the user can enter a date at which the benefits from the project will begin to decline. If no values are entered in the "Value" column the default values will be used. Once the user is finished click the button below the chart to return to the PDIM Main Page.

Escalation Factor	Description	Inputs Affected	Value	Default Value
Population Growth Factor	This escalation factor represents the customer population growth of the service area that the project impacts.	View List of Inputs		2.00%
Load Growth Factor	This escalation factor represents the electricity load growth of the service area that the project impacts.	View List of Inputs		2.60%
Economic Inflation Factor	This escalation factor represents the approximate economic inflation in the area that the project is located.	View List of Inputs		2.90%
Energy Price Factor	This escalation factor represents the approximate inflation rate of costs related to energy (i.e. whole sale electricity price, cost of ancillary services, congestion costs)	View List of Inputs		2.50%
Final year of benefits	This parameter represents the final year that project will yeild benefits; after this year all benefits will decline to zero. This parameter could be defined factors such as the useful lifetime of smart grid assets installed.	This parameter affects all benefit calculations. This year determines when the benefits (calculated by determining the delta between project and baseline inputs) of the project decline to zero		2035

Return to DIM Main Page

Escalation factors are used to project input data beyond the first five years of data entry[5]. There are four primary escalation factors: population growth, load growth, economic inflation, and energy price. You can view the inputs that these inflation factors affect by clicking the buttons in the "Inputs Affected" column. Each escalation factor has a default value that varies by NERC region. If the default escalation factor values need to be altered, you can enter your own escalation factors in the "Value" column of the table.

This page is also where you enter the final year for which benefits from the smart grid's technology are expected. After this year, all benefits are assumed to be zero. This parameter could be defined by considerations such as the useful lifetime of smart grid assets installed.

Once you finish reviewing or modifying the escalation factors and final year of benefits, click the "Return to DIM Main Page" buttons. For more details about escalation factors, refer to Appendix D.3 Input Escalation.

DIM Step III

To proceed to Step III of the DIM click the "Step III" button on the DIM Main page.

In this step, you enter the smart grid project cost data. These data are used to calculate the present value of annual capital costs associated with the smart grid project. The cost input page is depicted in Figure 18.

In the top table, enter values for "Discount Rate" and "Use Custom Cost Schedule." The discount rate will be used to determine the present value of future cash flows. You may use a custom cost schedule or a simple cost schedule based on an amortization of total capital costs over a specified period. Selecting "Yes" for "Use Custom Cost Schedule" shades out unneeded cells in the table. Enter the specific capital cost schedule in the bottom table and click the "Finish Cost Data Entry" button when complete. Selecting

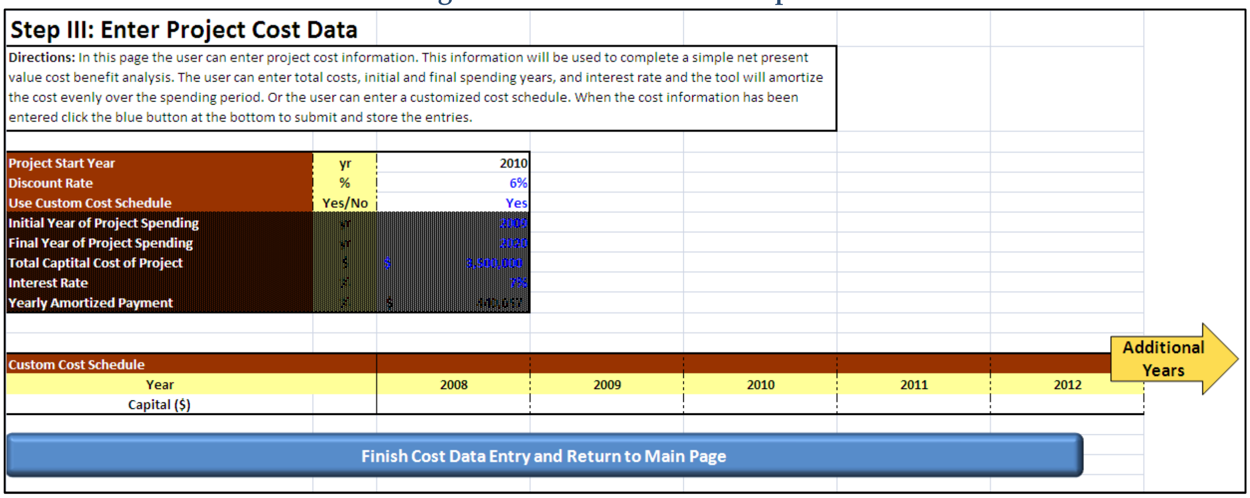
[5] See section 2.4 Benefit Calculations or section 3.2.3 Computational Module (CM) for further explanation.

"No" for the "Use Custom Cost Schedule" question shades out the custom cost schedule table and leaves the rest of the top table open for entering data.

The rest of the questions in the top table set the initial and final year of spending and determine the yearly amortized payment over that period. The amount of the yearly payment is automatically calculated and displayed in the bottom cell of the table. For a detailed explanation of the cost calculations used in the SGCT, please refer to Appendix
C.23 Cost Calculations.

After all required data have been entered into the table click the blue "Finish" button at the bottom of the page to submit the data and return to the DIM Main page.

Figure 18. Cost Calculation Inputs



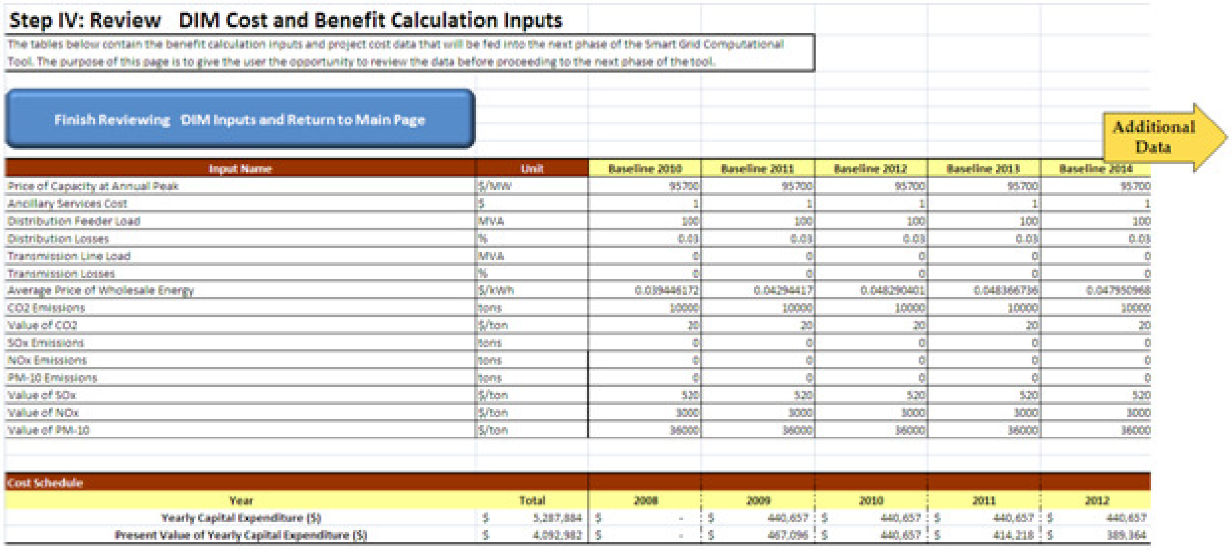
DIM Step IV

To proceed to Step IV of the DIM, click the "Step IV" button on the DIM Main page. This presents the "Review Inputs" page, depicted in Figure 19.

The purpose of Step IV is to allow the review of all of data entries in a compact summary form before proceeding to the Computational Module, where the data will be used to calculate results. There are two tables in this page: one that summarizes the benefit calculation input (data entered in Step II) and one that summarizes the project cost data (data entered in Step III). These tables cannot be altered since they are strictly for review purposes. If you see input data you would like to change, return to the DIM Main page and go to the step in the DIM that coincides with that data. Once satisfied with these inputs, click the "Finish" button at the top of the page to return to the DIM Main page.

Finally click the "Step V" button to exit the DIM and begin the CM. After this button is clicked, the CM main page will appear. The data input review pages will remain visible so you can review your inputs at any time.

Figure 19. DIM Output Summary Table



Step IV: Review DIM Cost and Benefit Calculation Inputs

The tables below contain the benefit calculation inputs and project cost data that will be fed into the next phase of the Smart Grid Computational Tool. The purpose of this page is to give the user the opportunity to review the data before proceeding to the next phase of the tool.

Finish Reviewing DIM Inputs and Return to Main Page

Additional Data

Input Name	Unit	Baseline 2010	Baseline 2011	Baseline 2012	Baseline 2013	Baseline 2014
Price of Capacity at Annual Peak	$/MW	95700	95700	95700	95700	95700
Ancillary Services Cost	$	1	1	1	1	1
Distribution Feeder Load	MVA	100	100	100	100	100
Distribution Losses	%	0.03	0.03	0.03	0.03	0.03
Transmission Line Load	MVA	0	0	0	0	0
Transmission Losses	%	0	0	0	0	0
Average Price of Wholesale Energy	$/kWh	0.039446172	0.04294417	0.048290401	0.048366736	0.047950968
CO2 Emissions	tons	10000	10000	10000	10000	10000
Value of CO2	$/ton	20	20	20	20	20
SOx Emissions	tons	0	0	0	0	0
NOx Emissions	tons	0	0	0	0	0
PM-10 Emissions	tons	0	0	0	0	0
Value of SOx	$/ton	520	520	520	520	520
Value of NOx	$/ton	3000	3000	3000	3000	3000
Value of PM-10	$/ton	36000	36000	36000	36000	36000

Cost Schedule						
Year	Total	2008	2009	2010	2011	2012
Yearly Capital Expenditure ($)	$ 5,287,884	$ -	$ 440,657	$ 440,657	$ 440,657	$ 440,657
Present Value of Yearly Capital Expenditure ($)	$ 4,092,982	$ -	$ 467,096	$ 440,657	$ 414,218	$ 389,364

4.3 Saving and Updating an Existing Analysis

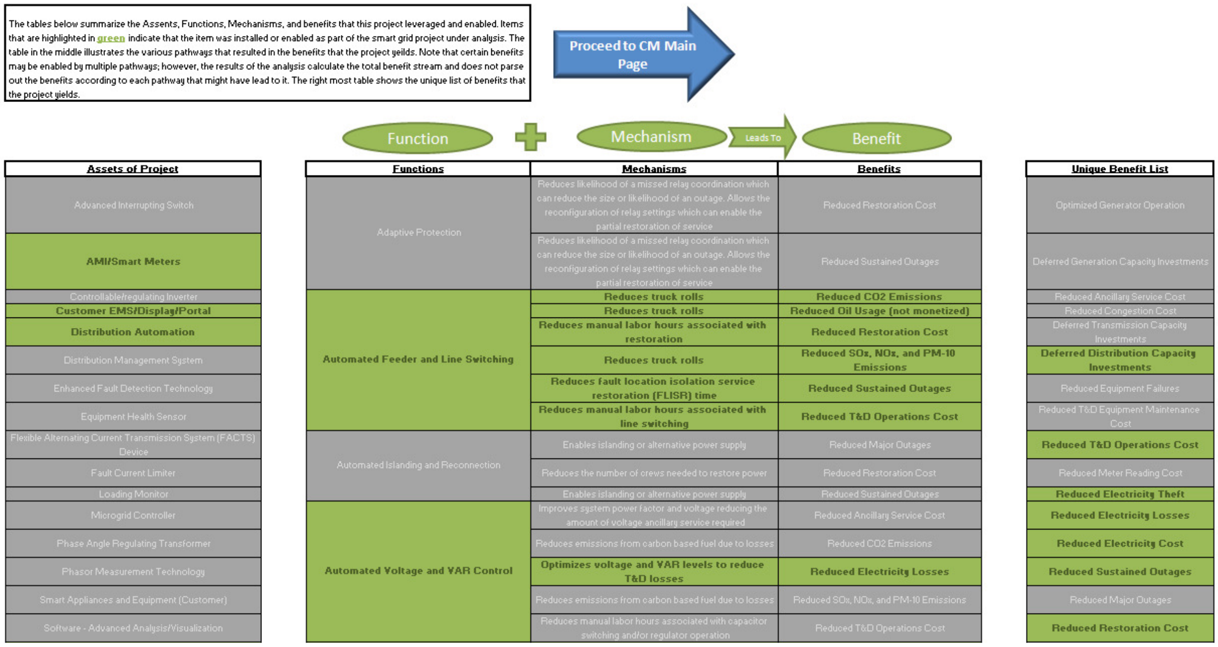
At this point all of the required inputs have been entered into the SGCT. As a result, the file uniquely represents the status of a particular project. You are strongly encouraged to save the file under a new, descriptive name so that the same file can be updated with new input data. Updating the analysis simply requires that the user return to the DIM Main page and work through steps I-V to update inputs or input new data for the years for which data hadn't been previously available. In order to change the assets, functions, and benefits of the project, navigate back to the PCM by clicking the "Go Back to the PCM" button on the DIM Main page, and then click the "Function-Benefit Chart is Incorrect" button on the "Function-Benefit Chart" page.

4.4 Running the Computational Module (CM)

The first screen visible after proceeding from the DIM is the "Review Benefit Pathways" screen, depicted in Figure 20. This page provides an overview of the Assets, Functions, Mechanisms, and Benefits that characterize the project under analysis. This screen is useful because it shows the explicit pathways that lead to each benefit; that is, it shows how the combinations of Functions and Mechanisms lead to the various benefits of the project. This information is especially useful to elucidate and understand the rationale that led to each benefit.

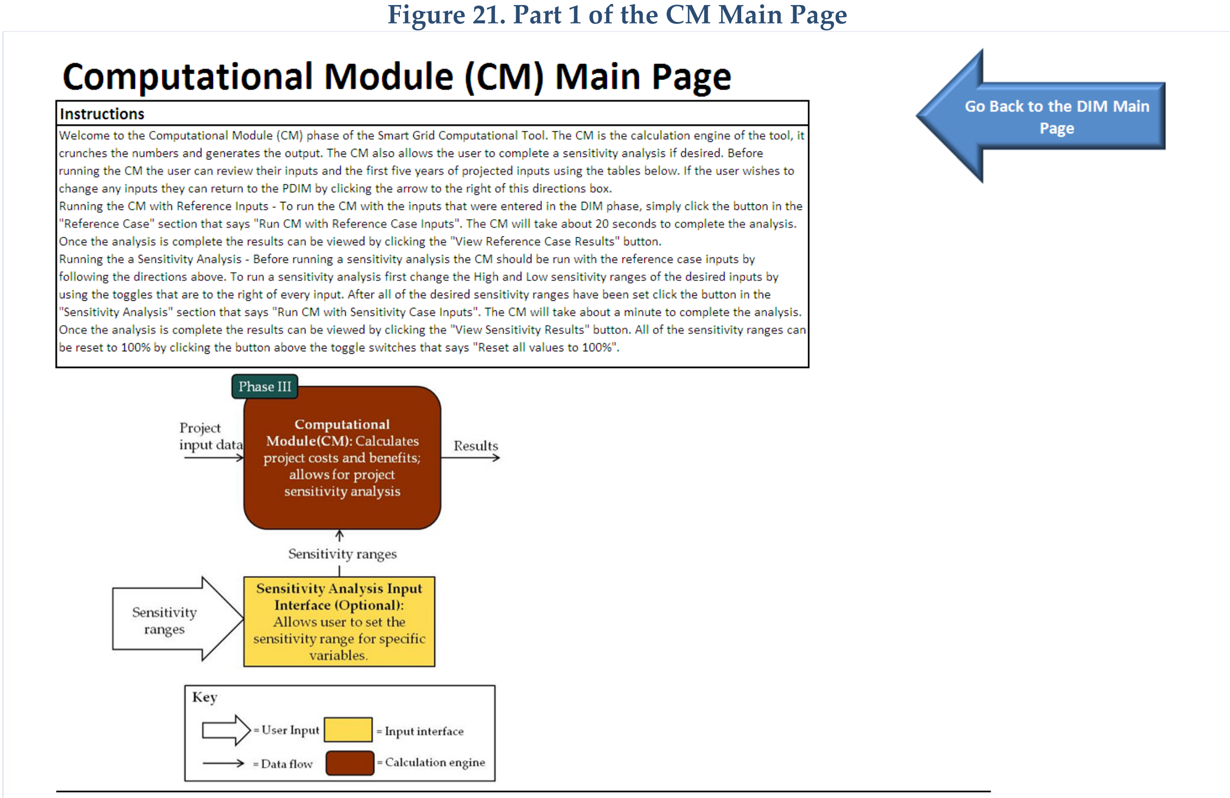
Note that certain benefits may be enabled by multiple pathways. However, the tool calculates the total benefit stream and does not parse out the benefits according to each pathway that might have lead to it. The rightmost table on this page shows the unique benefits that the project yields. After reviewing this page, click on the blue arrow to proceed to the CM Main page.

Figure 20. The Review Benefit Pathways Screen



The first part of the CM Main page, depicted in Figure 21, provides a brief introduction to the CM as well as some instructions on how to use the CM and a summary graphic. In the upper right hand corner is a button that allows the user to return to the DIM Main page.

Figure 21. Part 1 of the CM Main Page

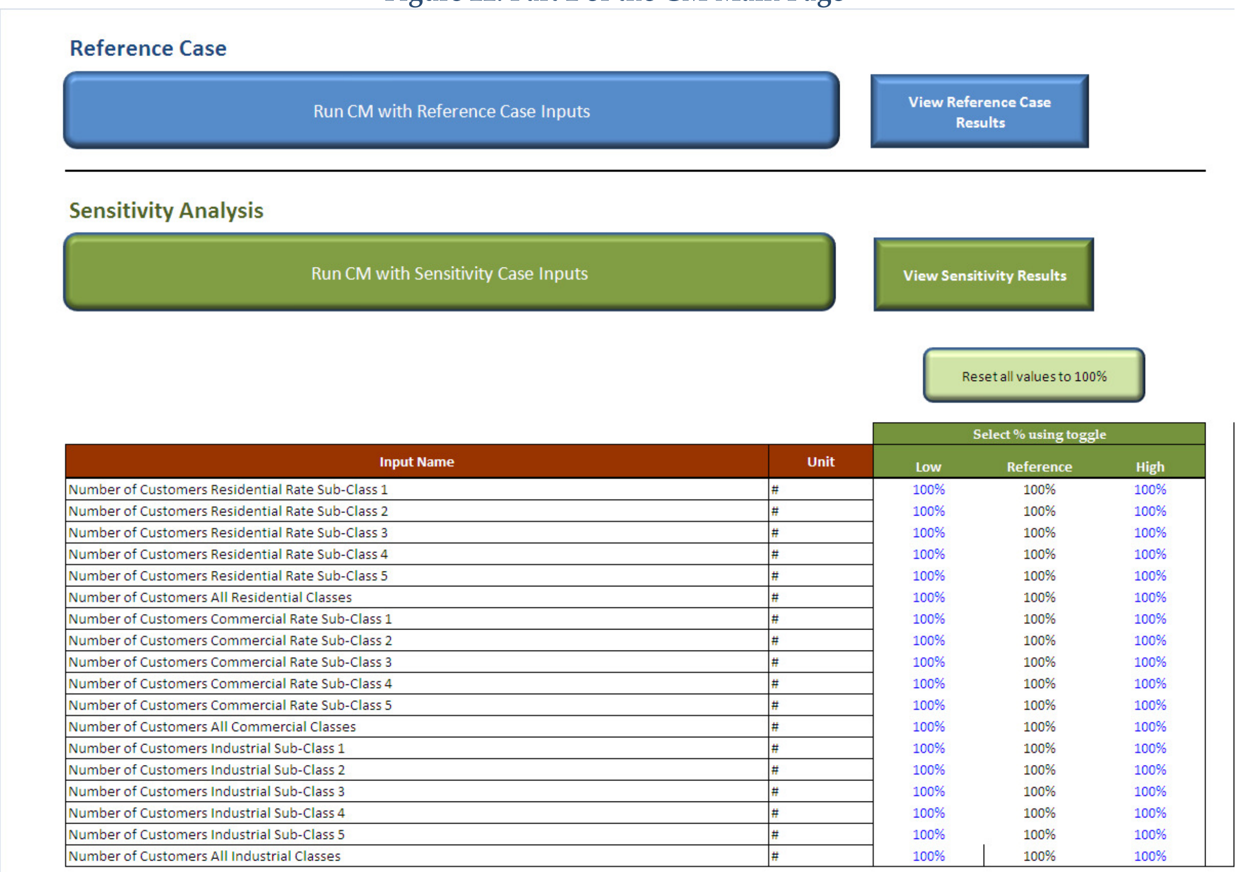


The second part of the CM Main page is depicted in Figure 22 below. This part of the CM Main page allows you to run the cost-benefit analysis with the inputs entered in the DIM, collectively referred to as the Reference Case, or it allows for an analysis to be run with high and low sensitivity case inputs, collectively referred to as the Sensitivity Case. In order to run the analysis with the Reference Case inputs, click the long blue button labeled "Run CM with Reference Case Inputs". The CM will take about 30 seconds to process the inputs. After the analysis is complete, results can be reviewed by clicking the blue button labeled "View Reference Case Results."

For an optional analysis, you can run the CM with Sensitivity Case inputs. Sensitivity Case inputs allow you to see how the benefits are impacted by variation in the input values. Before running the CM with Sensitivity Case inputs, the user must set the high and low sensitivity ranges of the inputs. A complete list of all inputs is located just below the buttons used to run the CM. The "Low" and "High" percentage toggles next to each input can be used to set a low and high range for each input individually.

After all of the desired sensitivity ranges have been set, click the "Run CM with Sensitivity Case Inputs" button in the "Sensitivity Analysis" section. The CM will take about a minute to complete the analysis. The results can be viewed by clicking the "View Sensitivity Results" button. All of the sensitivity ranges can be reset to 100% by clicking the "Reset all values to 100%"button above the toggle switches. After making any changes to the PCM and/or DIM, all CM analyses should be re-run.

Figure 22. Part 2 of the CM Main Page



Input Name	Unit	Select % using toggle		
		Low	Reference	High
Number of Customers Residential Rate Sub-Class 1	#	100%	100%	100%
Number of Customers Residential Rate Sub-Class 2	#	100%	100%	100%
Number of Customers Residential Rate Sub-Class 3	#	100%	100%	100%
Number of Customers Residential Rate Sub-Class 4	#	100%	100%	100%
Number of Customers Residential Rate Sub-Class 5	#	100%	100%	100%
Number of Customers All Residential Classes	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 1	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 2	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 3	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 4	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 5	#	100%	100%	100%
Number of Customers All Commercial Classes	#	100%	100%	100%
Number of Customers Industrial Sub-Class 1	#	100%	100%	100%
Number of Customers Industrial Sub-Class 2	#	100%	100%	100%
Number of Customers Industrial Sub-Class 3	#	100%	100%	100%
Number of Customers Industrial Sub-Class 4	#	100%	100%	100%
Number of Customers Industrial Sub-Class 5	#	100%	100%	100%
Number of Customers All Industrial Classes	#	100%	100%	100%

A table of input values, depicted in Figure 23, is located to the right of the sensitivity toggles. This table contains all of the Reference Case values of all inputs for the first five years of the project as well as the next five years of projected values. Projected values are calculated based on the escalation factors that were set in Step II of the DIM.

Figure 23. Input Review

Reference Case Values (project)					Projections -->				-->
2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
95,700	95,700	95,700	95,700	95,700	98,093	100,545	103,058	105,635	108,276
1	1	1	1	1	1	1	1	1	1
90	90	90	90	90	91	93	94	95	96
0	0	0	0	0	0	0	0	0	0
-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-
0	0	0	0	0	0	0	0	0	0
9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000	9,000
20	20	20	20	20	20	21	21	22	22

Additional Inputs

4.5 Reviewing the SGCT Results

There are two general types of results to review: Reference Case Results and Sensitivity Case Results. The Reference Case Results include summary tables of the yearly benefits and costs, pie charts of the benefits, and a Net Present Value (NPV) analysis. Sensitivity Case Results include bar charts, line charts, and tables that summarize the benefits given the different sensitivity scenarios. Each type of result is presented in its own page. The different pages are summarized below.

Reference Case Results

Each of the results tabs that correspond to the Reference Case Results is explained below.

Result Tables – This page contains two tables that summarize the value of all the benefits and costs over the entire analysis period. The top table contains the *annual* benefit and cost values. The bottom table contains *cumulative* benefit and cost values. Benefits are organized by major benefit categories (i.e. Economic, Reliability, Environmental, and Security) and benefit sub-category (i.e. Theft Reduction, Power Interruption, and Power Quality). All values are in nominal terms.

Result Charts – This page contains three pie charts and underlying tables that summarize the total cumulative benefits over the entire analysis period. The first pie chart and table summarize benefits by the major benefit category. The second pie chart and table summarize the economic benefits by sub-category. The third pie chart and table summarize the reliability benefits by individual benefit. All values are in nominal terms.

Net Present Value Analysis – This page contains a table and two charts that summarize the project's benefits and costs in present value terms. The table contains all of the annual and cumulative costs and benefits in both nominal and present value terms. It also contains the annual and cumulative net present value of the project (the difference between the present value of costs and benefits). The two graphs below the tables show the present value of costs, benefits as well as the NPV. The top graph shows the annual values while the bottom graph shows the cumulative values.

Sensitivity Case Results

Each of the results tabs that correspond to the Sensitivity Case Results is explained below.

Sensitivity Charts – The charts on this page show how the total benefit of the project can vary given the range of values for major benefit categories, benefit sub-categories, and individual benefits. Each chart has a red vertical line that denotes the total value of all project benefits in the Reference Case. The blue bars that straddle the red line denote the range of values that the total project benefit can have given the variability of the benefit category, sub-category, or individual benefit. The graphs on the left side of the page show the sensitivity analysis for a single analysis year. The analysis year can be changed by toggling the green drop-down cell at the top of the page. The graphs on the right show the sensitivity analysis for the cumulative benefit over the entire analysis period.

Sensitivity Graphs – This page contains four line graphs, a bar chart, and four summary tables. The four line graphs compare the total annual and cumulative gross benefits for the Low, Reference, and High Cases over the analysis period. The two line graphs on the left side are in nominal dollars and the two graphs on the right are in present value dollars. The bar chart shows the cumulative benefits of the project by major benefit category for the three cases. The four tables on the right side of the page summarize the annual and cumulative benefits of the project for the three cases. Two of the tables are in nominal dollars and two of the tables are in present value dollars.

4.6 Conclusion

The SGCT identifies the functions and mechanisms to be demonstrated by a smart grid project, and analyzes the costs and benefits to determine the project's overall value. By using this tool to analyze SGIG and SGD projects and aggregating the results, the DOE will be able to consider broader impacts of smart grid technologies for the nation. The DOE will also be able to use the SGCT to determine the incremental benefits of the SGIG and SGD programs. These analyses will help the DOE understand the impact of its investments on the growth and implementation of the smart grid, thereby helping the DOE refine its strategy with respect to encouraging investment into future smart grid technologies.

Project teams can use the SGCT to determine and compare project costs and benefits, and to gain a clearer understanding of the financial benefits of smart grid technology and systems. Furthermore, project teams will be able to use the SGCT to analyze costs and benefits of smart grid projects under different scenarios and assumptions. Finally, project teams and associated organizations can leverage the insights provided by the SGCT to inform future smart grid investment.

The monetary value of the benefits calculated by the SGIG could be attributed to ratepayers, utilities, society, or a combination of these parties depending on the nature of the benefit. However, the SGCT does not allocate dollars to these parties. Rather, it aggregates all benefits regardless of who the likely benefactor is. Therefore, the user must designate the various benefits that the SGCT calculates. The tool was not specifically designed to yield results that will be used in regulatory hearings or other similar proceedings. Ultimately, the results of the tool are intended for educational purposes only, and are meant to provide insight that can be used in conjunction with other analyses to more clearly understand the impact and benefits of a smart grid project.

Appendix A: Asset, Function, and Benefit Descriptions

Table A-1. Descriptions of Assets

Asset	Description
Advanced Interrupting Switch	Switches or technology that can detect and clear faults more quickly than traditional switches or without a traditional reclosing sequence.
AMI/Smart Meter	Electricity meters that utilize two-way communication in order collect electricity usage and related information from customers and deliver information to customers. AMI stands for "Advanced Metering Infrastructure."
Controllable/regulating Inverter	AC to DC converters that regulate voltage and can be controlled remotely. These devices can significantly increase the integration of renewable or intermittent sources of electricity.
Customer EMS/Display/Portal	Devices or portals through which energy and related information can be communicated to and from utilities or third party energy service providers. These devices can also help customers control electricity usage automatically by leveraging signals from the utility or owner set parameters. EMS stands for "Energy Management System"
Distributed Generator (diesel, PV, wind)	Distributed generators generate electricity from many small dispersed sources. Industrial countries generate most of their electricity in large centralized facilities, such as fossil fuel (coal, gas powered) nuclear or hydropower plants and typically transmit the electricity long distances. Distributed generators produce electricity on a smaller scale and produce electricity very near where it is used, perhaps even in the same building. Examples of technologies that are suitable for use as a distributed generator include PV, wind, diesel generators, fuel cells, microturbines, combined heat and power systems, Stirling engines, and reciprocating engines.
Distribution Automation	Distribution automation (DA) comprises devices that can be used to perform automatic switching, reactive device coordination, or other feeder operations/control.
Distribution Management System	A Distribution Management System (DMS) is a utility information technology (IT) system capable of integrating, organizing, displaying, and analyzing real-time or near-real-time electric distribution data in order to offer a wide range of operational benefits. These systems can improve operations, increase system efficiency, optimize power flows, prevent overloads, improve power flows, prevent overload, improve outage management, and enable other decision support tools. These systems can integrate traditional IT information systems such as GIS, OMS, and CIS to create a system that allows for a more holistic and automated treatment of the distribution management problem.
Enhanced Fault	Enhanced fault detection technology enables higher precision and greater discrimination of fault location and type

Asset	Description
Detection Technology	with coordinated measurement among multiple devices. For distribution applications, this technology can detect and isolate faults without full-power re-closing, reducing the frequency of through-fault currents. Using high resolution sensors and fault signatures, this technology can better detect high impedance faults. For transmission applications, this technology will employ high speed communications between multiple elements (e.g., stations) to protect entire regions, rather than just single elements. It can also use the latest digital techniques to advance beyond conventional impedance relaying of transmission lines.
Electricity Storage device (e.g., battery, flywheel, EV, etc.)	Electricity storage devices store electric energy for use at a later time. There are many technologies that could be used to provide grid energy storage and examples include: batteries, electric vehicles, compressed air storage, flywheels, thermal storage, pumped hydro storage, and hydrogen.
Equipment Health Sensor	Monitoring devices that automatically measure and communicate equipment characteristics that are related to the "health" and maintenance of the equipment. These characteristics can include, but are not limited to temperature, dissolved gas, and loading. These devices can also automatically generate alarm signals if the equipment characteristics reach critical or dangerous levels.
FACTS Device	A power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability.
Fault Current Limiter	Devices that can be inserted into the grid to automatically limit the amount of through current the system experiences during a fault event.
Loading Monitor	Technology that can measure and communicate line, feeder, and/or device loading data via a communication network in real- or near real-time.
Microgrid Controller	Devices that enable and control microgrids. Microgrids are electrical systems that include multiple loads and distributed energy resources that can be operated in parallel with the grid or as an electrical island.
Phase Angle Regulating Transformer	Transformers that enable phase angle control between the primary (source) and the secondary (load) sides to create a phase shift between the primary side voltage and the secondary side voltage. The purpose of this phase shift is to control the real power flow through interconnected power systems.
Phasor Measurement Technology	The phasor measurement units, phasor data concentrators, communications technology, and advanced software applications that enables system operators to collect and analyze synchrophasor data from the bulk transmission system.
Smart Appliances and	An appliance (for example, thermostats, pool pumps, clothes washers/dryers, water heaters, etc.) that includes the

Asset	Description
Equipment (Customer)	intelligence and communications to enable automatic or remote control based on user preferences or external signals from a utility or third-party energy service provider. A smart appliance may utilize a home area network to communicate with other devices in the customer's premise, or other channels to communicate with utility systems.
Software - Advanced Analysis/Visualization	Systems installed to analyze grid information or help human operators.
Two-way Communications (high bandwidth)	A two-way communications infrastructure that can network one or more parts of the smart grid via secure, high speed, high bandwidth connections. This infrastructure system serves as the backbone of the customer systems, AMI, distribution, and transmission smart grid systems.
Vehicle to Grid Charging Station	An electric vehicle (EV) charging station that utilizes communications technology to enable it to intelligently integrate two-way power flow, enabling electric vehicle batteries to become a useful utility asset.
Very Low Impedance (High Temperature Superconducting) cables	Cables that utilize conducting materials that are very low impedance (VLI), which can enable better power flow control. Cables that utilize High Temperature Superconducting (HTS) conductor would be characterized as a VLI cable. HTS cables may enable additional benefits such as lower losses, increased power density, and self-fault limiting.

Table A-2. Descriptions of Functions

Function	Description
Adaptive Protection	Adaptive protection uses adjustable protective relay settings (e.g., current, voltage, feeders, and equipment) that can change 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 distributed energy resource (DER) penetration.
Automated Feeder and Line Switching	Automated feeder and line switching is realized through automatic isolation and reconfiguration of faulted segments of distribution feeders or transmission lines 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 transmission and distribution (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.
Automated Voltage and VAR Control	Automated voltage and VAR (volt-ampere reactive) 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.
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 could be able to optimize toward multiple goals such as cost, reliability, convenience, and environmental impact.
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 in order to detect abnormal conditions (e.g., high number of equipment operations, temperature, or vibration). Asset managers and operations personnel can then be automatically notified to respond to conditions that increase the probability of equipment failure.
Distributed Production of Electricity	Smart grid assets can allow utilities to remotely operate distributed generation systems to control output, defer upgrades to generation and T&D assets, and improve voltage regulation. Distributed generation includes dispatchable, distributed generation such as combined heat and power, fossil fuel powered backup generators, bio-fuel powered backup generators (e.g., biodiesel, waste to energy, digester gas) or geo-thermal energy. It also includes variable, distributed generation such as solar and wind.
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.

Function	Description
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.
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. Fault current limiting can also be achieved through the implementation of special stand alone devices known as Fault Current Limiters (FCLs) which act to automatically limit high through currents that occur during faults.
Power Flow Control	Flow control requires techniques that are applied at transmission and distribution levels to influence the path that power (real and reactive) travels. This functionality is enabled by tools such as flexible AC transmission systems (FACTS), phase angle regulating transformers (PARs), series capacitors, and very low impedance superconductors.
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.
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.
Storing Electricity for Later Use	Remote utility control of electricity storage inflow/outflow reduces energy costs and enhances power generation and T&D capacity utilization.
Wide Area Monitoring, Visualization, & Control	Wide area monitoring and visualization requires time synchronized sensors, communications, and information processing that makes it possible for the condition of the bulk power system to be observed and understood in real-time so that protective, preventative, or corrective action can be taken.

Table A-3. Description of Benefits

Benefit	Description
Deferred Distribution Capacity Investments	As with the transmission system, reducing the load and stress on distribution elements increases asset utilization and reduces the potential need for upgrades. Closer monitoring and load management on distribution feeders could potentially extend the time before upgrades or capacity additions are required.
Deferred Generation Capacity Investments	Utilities and grid operators ensure that generation capacity can serve the maximum amount of load that planning and operations forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Reducing peak demand and flattening the load curve should reduce the generation capacity required to service load, and lead to cheaper electricity for customers.
Deferred Transmission Capacity Investments	Reducing the load and stress on transmission elements increases asset utilization and reduces the potential need for upgrades. Closer monitoring, rerouting power flow, and reducing fault current could enable utilities to defer upgrades on lines and transformers.
Optimized Generator Operation	Better forecasting and monitoring of load and grid performance would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost. The coordinated operation of energy storage, distributed generation, or plug-in electric vehicle assets could also result in completely avoiding central generation dispatch.
Reduced Ancillary Service Cost	Ancillary services are necessary to ensure the reliable and efficient operation of the grid, such as spinning reserve and frequency regulation. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. Ancillary services could be reduced if: generators could more closely follow load; peak load on the system was reduced; power factor, voltage, and VAR control were improved; or information available to grid operators were improved.
Reduced CO_2 Emissions	Functions that provide this benefit can do so by reducing vehicle miles, decreasing the amount of central generation needed to their serve load (through reduced electricity consumption, reducing electricity losses, or more optimal generation dispatch), and or reducing peak generation. These impacts translate into a reduction in CO2 emissions produced by fossil-based electricity generators and vehicles.
Reduced Congestion Cost	Transmission congestion is a phenomenon that occurs in electric power markets. It happens when scheduled market transactions (generation and load) result in power flow over a transmission element that exceeds the available capacity for that element. Since grid operators must ensure that physical overloads do not occur, they will dispatch generation so as to prevent them, thus interfering with market transactions and creating added transactions to monetize capacity access. The functions that provide this benefit provide lower cost energy, decrease loading on system elements, shift load to off-peak, or allow the grid operator to manage the flow of electricity around constrained interfaces (i.e. dynamic line capability or power flow control).

Benefit	Description
Reduced Electricity Cost	Functions that provide this benefit could help alter customer usage patterns (demand response with price signals or direct load control), or help reduce the cost of electricity during peak times through either production (DG) or storage.
Reduced Electricity Losses	Functions that provide this benefit could help manage peak feeder loads, reduce electricity throughput, locate electricity production closer to the load, and ensure that voltages remain within service tolerances, while minimizing the amount of reactive power provided. These actions make the system more efficient for a given load served, or by actually reducing the overall load on the system.
Reduced Electricity Theft	Smart meters can typically detect tampering. Moreover, a meter data management system can analyze customer usage to identify patterns that could indicate diversion. These new capabilities can lead to a reduction in electricity theft through earlier identification and prevention of theft.
Reduced Equipment Failures	Reducing mechanical stresses on equipment increases service life and reduces the probability of premature failure. This can be accomplished though enhanced monitoring and detection, reduction of fault currents, enhanced fault protection, or loading limits based on real-time equipment or environmental factors.
Reduced Major Outages	A major outage is defined using the beta method, per IEEE Std 1366-2003 (IEEE Power Engineering Society 2004). The monetary benefit of reducing major outages is based on the value of service (VOS) of each customer class. The VOS parameter represents the total cost of a power outage per MWh. This cost includes the value of unserved energy, lost productivity, collateral damage, the value of penalties and performance based rates. Functions that lead to this benefit can mitigate major outages by allowing the system to be reconfigured on the fly to help restore service to as many customers as possible, enable a quicker response in the restoration effort, or mitigate the impact of an outage through islanding or alternative power supply.
Reduced Meter Reading Cost	Advanced Metering Infrastructure (AMI) equipment eliminates the need to send someone to each location to read the meter manually leading to reduced meter operations costs. AMI technology can also reduce costs associated with other meter operations such as connection/disconnects, outage investigations, and maintenance.
Reduced Momentary Outages	By locating faults more accurately or adding electricity storage, momentary outages could be reduced or eliminated. Moreover, fewer customers on the same or adjacent distribution feeders would experience the momentary interruptions associated with reclosing. Momentary outages last <5 min in duration. The benefit to consumers is based on the value of service.
Reduced Oil Usage (not monetized)	The functions that provide this benefit eliminate the need to send a line worker or crew to the switch or capacitor locations in order to operate them, eliminate the need for truck rolls to perform diagnosis of equipment condition, and reduce truck rolls for meter reading and measurement purposes. This reduces the fuel consumed by a service vehicle or line truck. The use of PEVs can also lead to this benefit since the electrical energy used by PEVs displaces the equivalent amount of oil. This benefit is quantified in terms of gallons of oil and is not monetized.

Benefit	Description
Reduced Restoration Cost	The functions that provide this benefit lead to fewer outages and/or help restore power quicker or with less manual labor hours, which results in lower restoration costs. These costs can include line crew labor/material/equipment, support services such as logistics, call centers, media relations, and other professional staff time and material associated with service restoration.
Reduced Sags and Swells	Locating high impedance faults more quickly and precisely and adding electricity storage will reduce the frequency and severity of the voltage fluctuations that they can cause. Installing advanced reclosers that only allow a limited amount of current to flow through them upon reclosing can also reduce voltage fluctuations. Moreover, fewer customers on the same or adjacent distribution feeders would experience the voltage fluctuation caused by the fault. The benefit to consumers is based on the value of service.
Reduced SOx, NOx, and PM-2.5 Emissions	Functions that provide this benefit can lead to avoided vehicle miles, decrease the amount of central generation needed to their serve load (through reduced electricity consumption, reduced electricity losses, more optimal generation dispatch), and or reduce peak generation. These impacts translate into a reduction in pollutant emissions produced by fossil-based electricity generators and vehicles.
Reduced Sustained Outages	A sustained outage is one lasting > 5 minutes, excluding major outages and wide-scale outages. The monetary benefit of reducing sustained outages is based on the value of service (VOS) of each customer class. The VOS parameter represents the total cost of a power outage per MWh. This cost includes the value of unserved energy, lost productivity, collateral damage, administrative costs, the value of penalties and performance based rates. Functions that lead to this benefit can reduce the likelihood that there will be an outage, allow the system to be reconfigured on the fly to help restore service to as many customers as possible, enable a quicker response in the restoration effort, or mitigate the impact of an outage through islanding or alternative power supply.
Reduced T&D Equipment Maintenance Cost	The cost of sending technicians into the field to check equipment condition is high. Moreover, to ensure that they maintain equipment sufficiently, and identify failure precursors, some utilities may conduct equipment testing and maintenance more often than is necessary. Online diagnosis and reporting of equipment condition would reduce or eliminate the need to send people out to check equipment resulting in a cost savings.
Reduced T&D Operations Cost	Automated or remote controlled operation of capacitor banks and feeder and line switches eliminates the need to send a line worker or crew to the switch location in order to operate it. This reduces the cost associated with the field service worker(s) and service vehicle.
Reduced Wide-scale Blackouts	The functions that lead to this benefit will give grid operators a better picture of the bulk power system, and allow them to better coordinate resources and operations between regions. This will reduce the probability of wide-scale regional blackouts.

Appendix B: Function to Benefit Rationale

This section explains how various functions can lead to different benefits. The content presented here represents the detailed rationale behind the content presented in Table 3 on page 14. Each subsection in this appendix is devoted to a single function.

B.1 Fault Current Limiting

Very high currents due to short circuits can cause severe mechanical stress on equipment, resulting in failure or damage over time. These high currents can be limited to safe levels by inserting an electrical resistance into the circuit between the sources of the fault current and the equipment that must be protected. This capability is generally sought for application at the transmission level, but some utilities may also apply fault current limiters (FCL) on distribution where cost effective.

FCLs are not commercially available at this time. Several equipment suppliers and research organizations (including DOE and EPRI) are pursuing the development of FCLs based on high temperature superconductivity (HTS) materials or semiconductor based devices. These advanced devices have a combination of performance characteristics that may make them practical for general application by utilities. However, this is several years away, and these will not likely be seen in near term projects. In the longer term, this function can lead to two benefits:

- Deferred Transmission Capacity Investments - Fault currents that exceed the interrupting capability of circuit breakers can lead utilities to either replace the breakers with higher capability units, or reconfigure one or more substations. Both solutions can be very expensive and challenging from an operational perspective, particularly for critical substations. An FCL can prevent currents from exceeding the interrupting ratings of circuit breakers, which would allow the utility to defer or eliminate the need for upgrades or reconfiguration.
- Reduced Equipment Failures - The FCL limits the level of fault current that flows through equipment, and reduces the associated mechanical stress and damage. This can increase equipment service life and reduce the probability of premature failure.

B.2 Wide Area Monitoring, Control, and Visualization

Wide area monitoring and Control (WAMC) is the ability to monitor and control transmission system conditions over large regions (multiple states) and display this information in ways that human operators can accurately interpret and act upon. Technologies such as phasor measurement units, data concentrators, and advanced software are used to provide a real-time operating picture of the bulk transmission system. This information will be available in grid control centers to help operators observe, analyze, and operate the system more precisely and reliably. This function can lead to six benefits:

- Optimized Generator Operation – All of the generators within an electrical interconnection are naturally synchronized with the system frequency. Each unit can produce real and reactive power, and contribute to the overall electrical stability of the interconnected system. Until recently, grid operators could only "observe" and analyze the stability performance of these generators using complex off-line simulation tools. WAMC, including phasor measurement units (PMUs), is enabling operators to observe the voltage and current waveforms of the bulk power system at very high levels of detail. This capability will provide deeper insight into the real-time stability of the power system, and the effects of generator dispatch and operation. It will allow operators to potentially optimize individual generators, and groups of generators, to improve grid stability during conditions of high system stress.

- Reduced Ancillary Service Cost - Ancillary services are necessary to ensure the reliable and efficient operation of the grid. Ancillary services are provided by generators, and generally include operating reserves, frequency regulation, and voltage and VAR support. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. To a great extent, the level of ancillary services required is based on extensive operating experience and planning studies. Because of limitations in operating information and coordination between regional power grids, ancillary service levels may be necessarily conservative to ensure grid reliability. By improving the information available to grid operators, it is possible that ancillary service levels could be reduced, decreasing the cost of energy for market participants and utilities.

- Reduced Congestion Cost – As discussed under Optimized Generator Operation, WAMC allows grid operators a high resolution view of the power system and its stability. In many cases, transmission capability is limited by stability, not thermal capacity. To the extent that WAMC could enable grid operators in raise the stability limit of a transmission line or system interface, congestion could be reduced without reducing grid reliability.

- Deferred Transmission Capacity Investments – Raising the stability limit of a transmission line or grid interface could defer an upgrade need to increase capacity and reduce congestion.

- Reduced Major Outages – WAMC could help improve grid stability, and help grid operators avoid conditions that could lead to generator tripping or other results that could cause outages.

- Reduced Wide-scale Blackouts – Wide area monitoring will give grid operators in each control area a better picture of the bulk power system and allow them to better coordinate resources and operations between regions. This enhanced coordination will reduce the probability of wide-scale blackouts.

B.3 Dynamic Capability Rating

Capability ratings for power lines and equipment are typically based on thermal limits. Because of the inherent electrical resistance of normal conductor, the more current they carry, the hotter they become. Ratings on equipment (like transformers) are limited by the amount of heat that can be tolerated before damage or degradation occurs. Ratings on transmission lines are typically based on how low the conductor sags due to heating. Some transmission lines are stability-limited, and are not operated up to their thermal limits.

Since ambient conditions like air temperature, wind speed, and moisture affect heat rejection from equipment, they can significantly affect the true power handling capability of lines and equipment. Utilities typically assign ratings to lines and equipment to account for seasonal changes, and also emergency conditions. These ratings are based on manufacturer specifications, utility standards, and operating experience. Although these ratings schedules attempt to account for changes in ambient conditions, they cannot account for the actual conditions in which system elements are operating at any point in time. For much of the time, these ratings are probably conservative, and may limit loading unnecessarily.

Dynamic Capability Rating utilizes sensors, information processing and communications to give grid operators a clearer picture of the true capability of network elements in real time. In cool or windy conditions, this could allow a grid operator to load a transmission line beyond its basic rating without overheating. In extremely hot weather, this could prevent a transformer from being loaded to the point of winding damage or failure. This function can lead to five benefits:

» Reduced Congestion Cost - Transmission congestion is a phenomenon that occurs in electric power markets. It happens when scheduled market transactions (generation and load) result in power flow over a transmission element that exceeds the available capacity for that element. Since grid operators must ensure that physical overloads do not occur, they will dispatch generation so as to prevent them. In some cases, a low cost generator may not be dispatched, because doing so would overload a transmission line. In such cases, a more expensive generator located on the "other side" of the limiting transmission line would be dispatched. The difference in cost between the more expensive generator and the less expensive generator is the congestion cost. The ability to increase the rating of a transmission line dynamically in response to actual conditions could free up capacity and avoid congestion.

» Deferred Transmission Capacity Investments - Monitoring electrical and environmental conditions for transmission elements in near-real time including lines and transformers could enable utilities to defer upgrades. For example, ambient temperature and wind speed are critical factors that affect the rated capability of a transmission line.

» Deferred Distribution Capacity Investments - Monitoring electrical and environmental conditions for distribution elements in near-real time including lines and transformers could enable utilities to defer upgrades. For example, ambient temperature and wind speed are critical factors that affect the rated capability of a distribution line.

» Reduced Equipment Failures - Since equipment capability ratings are based on heating and the ability of the equipment to reject heat, ambient temperature and wind speed are critical factors in determining the physical impact of load on equipment such as transformers. Limiting the rating on equipment in extreme temperature conditions can increase increasing service life and reduce the probability of premature failure.

» Reduced Wide-scale Blackouts - Dynamic capability ratings will give grid operators a better picture of the condition of critical system components, including key transmission lines. For example, during a very hot day it would be possible for the real rating of a transmission line to be lower than the rating in the grid operations computer. Providing the grid operators with the actual information could reduce the probability of overloading the line and causing a critical fault that could trigger a blackouts.

B.4 Power Flow Control

In AC power systems, the impedance of lines and transformers determines how power flows from generators to load. As electricity follows "the path of least resistance," it does not necessarily go where engineers and grid operators would prefer. By increasing or decreasing the impedance of a line or transformer (resistance and reactance), power flow can be changed.

Today, power flow control can be done with phase angle regulating transformers (PARs) or Flexible AC Transmission System (FACTS) devices. However, these solutions are often expensive, and they are not widely applied. New technologies such as superconducting cables hold promise due to their very low impedance, and could be used in combination with other devices to regulate power flow over critical areas of the system. This function provides five benefits:

» Reduced Congestion Cost - Transmission congestion costs are incurred when more expensive generation must be dispatched to avoid overloading a transmission line or interface. The ability to control impedance and "steer" power around a constrained interface could avoid congestion and its associated cost. As an example, assume a transmission line had a rating of 1,000 MW. Based on the scheduled dispatch at a particular time, the forecasted power flow over the line based on scheduled energy transactions would be 1,100 MW. By utilizing a controllable impedance element, the grid operator could draw power away from the limiting line, preventing the overload, while still delivering the desired power.

» Deferred Transmission Capacity Investments - load growth and generation additions can lead to increased loading on lines and transformers, to the point where transmission capacity investments become necessary. By managing power flow on critically loaded system elements using power flow control. For example, it could be possible for a utility to delay adding transmission capacity for one or more years without running the risk of an overload. Each year that a capital investment can be deferred can yield a significant savings in the utility's revenue requirement (equal to the capital carrying charge of the upgrade). Therefore, power flow control could yield direct savings based on the time that it could postpone a capacity investment.

» Reduced Electricity Losses – The ability to control power flows can enable engineers and grid operators to optimize power flows to reduce system losses. This could be accomplished by rerouting power to relieve critically loaded elements or to more evenly load multiple system elements. Since losses grow exponentially with load, reducing peak losses or more evenly loading the system can reduce losses overall while transmitting the same amount of power.

» Reduced CO_2 Emissions - Reducing the impedance of the T&D system reduces energy losses, and consequently, the generation required to serve load. Provided that the generation reduced is fossil-based, polluting emissions are reduced.

» Reduced SO_x, NO_x, and PM-2.5 Emissions - Reducing the impedance of the T&D system reduces energy losses, and consequently, the generation required to serve load. Provided that the generation reduced is fossil-based, polluting emissions are reduced.

B.5 Adaptive Protection

Detecting and clearing electrical faults (short circuits) is critically important for ensuring public safety, preserving property, and minimizing damage to the electrical system itself. Faults are detected using protective relays that monitor current and send signals to circuit breakers or switches when the current exceeds set points. (Fuses are also used on distribution feeders, and sometimes as backup for circuit breakers to protect equipment such as large transformers.) Electric power systems are protected by complex systems of relays and switching devices whose settings and operation is carefully designed and coordinated by engineers as part of initial system implementation. Protection schemes are designed to provide reliable fault clearing under expected conditions, and are not changed.

Adaptive protection means that relay settings and protection schemes can be changed in response to changing conditions. For example, a distribution feeder might be designed with relays set to trip if the current flowing from the substation exceeds a predetermined level. If generation was added to the feeder, it might require that the existing relay settings be changed to provide optimum protection. Since the feeder generation could come on or off, it might make protection highly complicated and expensive. By allowing the protection settings to be changed, the utility can ensure that the feeder is adequately protected, and that the generator can be integrated without prohibitive cost. Such a capability will also prove useful for reconfiguring feeder connections during outage or load transfer operations. This function can provide two benefits:

- Reduced Sustained Outages - Modifying protection settings in response to changing conditions could enable utilities to better isolate system faults, and reduce the scope and duration of outages. Adaptive protection reduces the likelihood that there will be an outage, and allows the system to be reconfigured on the fly to help in restoring service to as many customers as possible.
- Reduced Restoration Costs - Fewer outages result in lower restoration costs incurred by the utility. These costs can include line crew labor/material/equipment, support services such as logistics, call centers, media relations, and other professional staff time and material associated with service restoration.

B.6 Automated Feeder and Line Switching

Utilities design distribution feeders with switches so that portions of the feeder can be disconnected to isolate faults, or de-energized for maintenance.[6] In most cases, these switches are manually operated, and require a service worker to travel to the switch location, coordinate switching orders with a dispatcher, and then physically operate the switch. Automatic Feeder Switching makes it possible to operate distribution switches autonomously in response to local events, or remotely in response to operator commands or a central control system.

Automatic Feeder Switching does not prevent outages; it simply reduces the scope of outage impacts in the longer term. This function is accomplished through the automatic isolation and reconfiguration of faulted segments of distribution feeders via sensors, controls, switches, and communications systems. Automatic Feeder Switching can reduce or eliminate the need for a human operator or field crew for operating distribution switches. This saves time, reduces labor cost, and eliminates "truck rolls." This function can provide six benefits:

- Reduced Transmission and Distribution Operations Cost - Automated or remote controlled switching eliminates the need to send a line worker or crew to the switch location in order to operate it. This reduces the cost associated with the field service worker(s) and service vehicle.

---

[6] This function presumes that the switching is done within the scope of a single feeder, and should not be confused with Real-Time Load Transfer which assumes that the un-faulted portion of a feeder could be served from an adjacent substation.

- Reduced Sustained Outages - Automated Feeder and Line Switching means that the faulted portions of feeders and lines can be isolated by opening switches. By reconnecting some customers quickly (within minutes), significant outage minutes can be saved. This only works when a significant number of customers receive service upstream of the fault, with an automated switch between them and the fault. This function presumes that the switching is done within the scope of a single feeder. Automatic switching does not prevent the outage for all customers; it simply reduces the scope of its impact in the longer term.

- Reduced Restoration Cost - Being able to operate distribution switches without rolling trucks means lower restoration costs.

- Reduced CO_2 Emissions – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.

- Reduced SO_x, NO_x, and PM-2.5 Emissions – Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.

- Reduced Oil Usage - Fewer truck rolls for switching means less fuel consumed by a service vehicle or line truck and leads to reduced oil usage.

B.7 Automated Islanding and Reconnection

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. This disconnection and reconnection of the microgrid and the interconnected electric grid would be done automatically as needed based on grid conditions. This function leads to two benefits:

- Reduced Sustained Outages - Automated islanding and reconnection means portions of the system that include distributed generation can be isolated from areas with excessive damage. Customers within the island, or microgrid, will be served by the distributed generation until the utility can restore service to the area. Only the customers in the island experience reduced outage time from this improved reliability. While the outage may affect wide areas, and large numbers of customers, the island will most likely be no larger than a single distribution feeder (i.e., < 5,000 customers) or smaller.

- Reduced Major Outages - Automated islanding and reconnection means portions of the system that include distributed generation can be isolated from areas with excessive damage. Customers within the island, or microgrid, will be served by the distributed generation until the utility can restore service to the area. Only the customers in the island experience reduced outage time from this improved reliability. While the outage may affect wide areas, and large numbers of customers, the island will most likely be no larger than a single distribution feeder (i.e., < 5,000 customers) or smaller.

- Reduced Restoration Cost- When an outage event occurs, customers in the island who would have otherwise experience an outage will not experience a service interruption. Therefore, the restoration area that crews need to attend to will be reduced which will reduce the number of crews needed to restore power and reduce costs.

B.8 Automated Voltage and VAR Control

Automated voltage and VAR control is performed through devices that can increase or lower voltage and can be switched or adjusted to keep the voltage in a required range. Control systems could determine when to operate these devices, and do so automatically. This function is the result of 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. By better managing voltage and VAR resources, the transmission and distribution network can be optimized for electrical efficiency (lower losses), and can allow utilities to reduce load through "energy conservation voltage reduction" while maintaining adequate service voltage. These load reductions will reduce the amount of generation required. This function provides five benefits:

» Reduced Ancillary Service Cost - Ancillary services are necessary to ensure the reliable and efficient operation of the grid. As discussed above, ancillary services are provided by generators, and voltage and VAR support. The level of ancillary services required at any point in time is determined by the grid operator and/or energy market rules. To the extent that reactive power resources can be better coordinated to reduce load and reactive power requirements from generation, ancillary service costs for voltage and VAR support could be reduced, decreasing the cost for market participants and utilities.

» Reduced Transmission and Distribution Operations Cost - Automated voltage and VAR control eliminates the need to send a line worker or crew to the location of reactive devices in order to operate them. This reduces the cost associated with the field service worker(s) and service vehicle. The impact of this benefit is determined by estimating the percentage of a field crew's time is dedicated to capacitor switching, and then estimating the time saved by the field service personnel.

» Reduced Electricity Losses - Coordinating the settings of voltage control devices on the transmission and distribution system ensures that customer voltages remain within service tolerances, while minimizing the amount of reactive power provided. Optimizing voltage and VAR in this way can reduce the amount of transmission and distribution losses associated with delivering a given amount of energy.

» Reduced CO_2 Emissions - Energy reductions achieved through improved efficiency and energy conservation voltage reduction will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

» Reduced SO_x, NO_x, and PM-2.5 Emissions - Energy reductions achieved through improved efficiency and energy conservation voltage reduction will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

B.9 Diagnosis and Notification of Equipment Condition

Some equipment such as transformers and circuit breakers are critical to providing electric service to customers. Utilities test and maintain this equipment periodically in an effort to ensure that it operates reliably over a long service life. Because of the large amount of equipment, and the labor intensity of taking measurements and analyzing results, testing and maintenance can be very expensive, and may fail to identify critical equipment conditions before they lead to failure.

This function is the 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). As a result, the function enables the equipment to automatically notify asset managers and operations to respond to a condition that increases a probability of equipment failure. This function results in seven benefits:

» Reduced Equipment Failures - Monitoring equipment "continuously" and receiving reports of its condition will help utilities identify potential trouble before it worsens and leads to failure.

» Reduced Transmissions and Distribution Equipment Maintenance Cost - The cost of sending technicians into the field to check equipment condition is high. Moreover, to ensure that they maintain equipment sufficiently, and identify failure precursors, some utilities may conduct equipment testing and maintenance more often than is necessary. Online diagnosis and reporting of equipment condition would reduce or eliminate the need to send people out to check equipment.

» Reduced Sustained Outages - Some equipment failures cause outages, and the time to restore power can be significant depending on the difficulty of the replacement and the time it takes to obtain a replacement device. By utilizing on-line diagnosis and reporting of equipment condition, utilities could identify equipment problems before they cause outages.

» Reduced Restoration Costs - Outages caused by equipment failure will require restoration, and the utility will incur costs as a result. In some cases, the utility may pay a premium for the equipment and labor needed to restore service on short notice.

» Reduced CO_2 Emissions – Fewer truck rolls for equipment replacement and diagnosis means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.

» Reduced SO_x, NO_x, and PM-2.5 Emissions – Fewer truck rolls for equipment replacement and diagnosis means less fuel consumed by a service vehicle or line truck and leads to reduced emissions.

» Reduced Oil Usage - Fewer truck rolls for equipment replacement and diagnosis means less fuel consumed by a service vehicle or line truck and leads to reduced oil consumption.

B.10 Enhanced Fault Protection

Typically, protective devices rely on high fault currents to cause them to operate. Some faults (like a line lying on the ground) may not cause enough fault current to ensure that protective relays sense the fault quickly. Another problem is that multiple relays may sense the same fault and operate to try and clear it. Enhanced protection could detect faults that are hard to locate, and clear them without reclosing that can damage equipment over time. Enhanced fault detection with higher precision and greater discrimination of fault location and type with coordinated measurement among multiple devices could 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 could better detect high impedance faults. This function provides five benefits:

» Reduced Equipment Failures - Enhanced fault protection may detect faults more quickly, and clear those without full-power reclosing that can subject equipment to repeated fault current. This reduces the mechanical stress and damage, increasing equipment service life and reducing the probability of premature failure. For example, a substation transformer might feed three distribution feeders, each of which experienced a high number of faults. Over time, the feeder faults and the reclosing used to isolate them would place a high degree of mechanical stress on the transformer windings. This stress could lead to failure of the transformer far sooner than its expected service life.

» Reduced Sustained Outages - Some faults can be difficult to detect and isolate. For example, a high impedance fault caused by a downed line lying on dry ground might not produce enough fault current to trip the closest circuit breaker or fuse, but it may create a fault that lasts long enough to cause an upstream circuit breaker to trip as a backup. (Relays are often coordinated to have multiple "zones" of protection, and a single relay may be intended to provide primary protection for one part of the system, and backup protection for another. Sometimes relays far from a fault can "overreach" and trip before the relay closest to the fault can clear it.) This would result in a larger than necessary number of customers experiencing the outage. With enhanced fault protection, a higher portion of hard-to-detect faults would be cleared by the closest device, and minimize the disruption to other customers.

» Reduced Restoration Cost - By more quickly and precisely locating and clearing faults, field service workers can spend less time searching for the cause of the fault. It is also possible that by better isolating the fault, less damage occurs.

» Reduced Momentary Outages - Many utilities use distribution feeder reclosers and sectionalizing schemes to isolate faults and restore service to as many customers as possible. Although many customers do not suffer the long term outage associated with the permanent fault, they experience momentary interruptions as the reclosers follow the sectionalizing scheme. Enhanced fault protection could isolate faults more precisely without full-power reclosing, and prevent momentary interruptions for many customers. (Momentary interruptions are outages that last less than 5 minutes in duration, and are typically a few seconds in length.)

» Reduced Sags and Swells - High impedance faults can be caused by tree contact, broken conductors lying on the ground, or other short circuits that do not cause fault currents high enough to trip relays. Locating high impedance faults more quickly and precisely will reduce the frequency and severity of the voltage fluctuations that they can cause. Moreover, fewer customers on the same or adjacent distribution feeders would experience the voltage fluctuation caused by the fault.

B.11 Real-Time Load Measurement and Management

Devices such as smart meters and appliance controllers can monitor the energy use of customer loads over the course of the day. These same devices can be used to help customer respond to pricing signals so that system load can be managed as a resource. 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 help customers make informed energy use decisions via real-time price signals, time-of-use (TOU) rates, and service options. This function can provide eleven benefits:

» Reduced Ancillary Service Cost - The increased resolution of customer load data will improve load models and help grid operators to better forecast energy supply requirements. Improved forecasts, along with the ability to reduce customer demand effectively during critical periods, could reduce reserve margin requirements.

» Deferred Distribution Capacity Investment - Load growth and feeder reconfiguration can lead to increased loading on lines and transformers, to the point where distribution capacity investments become necessary. Smart meters and AMI will allow utilities to monitor customer loads and voltage more closely, and provide a platform for sending pricing signals that could influence consumption patterns. This could enable utilities to better anticipate and monitor feeder loading, and operate the distribution system closer to its limits. For example, it could be possible for a utility to delay building a new distribution feeder for one or more years without running the risk of low voltage problems. Each year that a capital investment can be deferred can yield a significant savings in the utility's revenue requirement (equal to the capital carrying charge of the upgrade). Therefore, Real-Time Load Measurement and Control could yield direct savings based on the time that it could postpone a capital investment.

» Reduced Meter Reading Cost – The data from smart meters can be automatically uploaded to a central meter data management system. This avoids the need to read meters manually, reducing the cost of performing this function.

» Reduced Electricity Theft - Smart meters can typically detect tampering. Moreover, a meter data management system can analyze customer usage to identify patterns that could indicate diversion.

» Reduced Electricity Losses - Peak load tends to affect delivery losses more than average load, and managing this peak could lead to improvements in electricity delivery efficiency. Being able to manage customer demand will give the utility the capability of reducing peak load, and thereby reduce delivery losses.

» Reduced Sustained Outages - Today, most utilities rely on customer calls to identify power outages, and customer service representatives to enter the outage information into a computer system. Outage management systems have been designed to interpret this outage information and estimate the location of the fault based on the information. AMI systems are being developed to perform outage detection based on the status of smart meters. This should improve the accuracy of outage notification, and reduce the time to restore service.

» Reduced Major Outages - Major outages occur as a result of hurricanes, ice storms, or other natural events that affect large geographical areas and tens of thousands of customers or more. Restoring electric service following these events typically takes a few days or more because of the massive damage that must be repaired on the distribution system. When utility crews move through an area making repairs to the distribution system, there are times when some customers fail to have their service restored because of unseen/overlooked damage. In such cases, when service is restored in the area, the utility crews may have left the area before the utility can receive a follow-up call from the customer saying that they are still without service. This means that the customer will be without service until a crew has time to come back to the area to fix the problem, and outage minutes will continue to increase. With AMI, utilities will be able to identify those customers who remain without power after the utility believes that power should be restored. This should make it easier to get a crew back to the location more quickly, and reduce the amount of time the customer is out.

» Reduced Restoration Cost – AMI systems are being developed to perform outage detection based on the status of smart meters. This should improve the accuracy of outage notification, and reduce the time to restore service. Reduced restoration times translate into reduced restoration costs because power can be restored with fewer restoration crew labor hours.

» Reduced CO2 Emissions – Manual meter reading requires that a person drive from meter to meter once each billing cycle. This produces CO_2 emissions from the vehicle. Eliminating the vehicle miles traveled eliminates the associated emissions.

» Reduced SOx, NOx, and PM-2.5 Emissions – Polluting emissions associated with vehicle miles travelled are eliminated.

» Reduced Oil Usage (not monetized) – Eliminating vehicle miles traveled with automatic meter reading eliminates the associated fuel consumption.

B.12 Real-Time Load Transfer

In areas that may have more than one distribution feeder, circuits may be switched and electrical feeds rerouted to make the distribution more efficient or more reliable. This function allows for real-time feeder reconfiguration and optimization to relieve load on equipment, improve asset utilization, improve distribution system efficiency, and enhance system reliability. This function provides three benefits:

» Deferred Distribution Capacity Investments - Load growth and feeder reconfiguration can lead to increased loading on lines and transformers, to the point where distribution capacity investments become necessary. Being able to automatically switch a portion of a distribution feeder A onto distribution feeder B will relieve the load on feeder A. In cases where feeder A and feeder B are connected to different substations, the load relief can have beneficial effects up to the substation level. This load shifting could enable utilities to postpone feeder upgrades for one or more years. Each year that a capital investment can be deferred can yield a significant savings in the utility's revenue requirement (equal to the capital carrying charge of the upgrade). Therefore, Real-Time Load Transfer could yield direct savings based on postponed capital investment.

» Reduced Electricity Losses - Higher line loading tends to affect delivery losses more than average load, and managing this peak could lead to improvements in electricity delivery efficiency. By being able to balance load among substation transformers and distribution feeders, the utility could reduce delivery losses.

» Reduced Major Outages - Transferring portions of a distribution feeder load from one substation to another could enable a utility to restore service to some outage customers more quickly than if they had to wait until their normal feeder was fully restored. Performing this load shifting manually would be impractical. However, by being able to do this remotely, a utility might be able to justify the cost in the interest of restoring some customers more quickly.

- Reduced CO_2 Emissions - Increased electricity delivery efficiency by managing peak line loads will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

- Reduced SOx, NOx, and PM-10 Emissions - Increased electricity delivery efficiency by managing peak line loads will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

B.13 Customer Electricity Use Optimization

A key characteristic of the smart grid is that it motivates and includes the customer. This function enables customers to observe their consumption patterns and modify them according to their explicit or implicit objectives. These could include minimizing cost, maximizing reliability, or purchasing renewable energy, among others. Nine benefits are provided:

- Deferred Generation Capacity Investments - Utilities build generation, transmission, and distribution with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. The smart grid can help reduce peak demand and flatten the load curve by giving customers the information and incentives to better manage their electricity usage. This should translate into lower infrastructure investments by utilities and cheaper electricity for customers.

- Deferred Transmission Capacity Investments – See Deferred Generation Capacity Investments, above.

- Deferred Distribution Capacity Investments – See Deferred Generation Capacity Investments, above.

- Reduced Electricity Cost - The information provided by smart meters and in-home displays may encourage customers to alter their usage patterns (demand response with price signals or direct load control), or conserve energy generally because they can see how much it costs and alter their behavior. Changes in usage can result in reductions in the total cost of electricity.

- Reduced Ancillary Service Cost - The ability to reduce customer demand effectively during critical periods could reduce reserve margin requirements.

- Reduced Congestion Cost – If customers have tools to manage their energy use, this could lead to a more conservative use of electricity especially at peak times, so less electricity must be passed through the T&D lines, which reduces congestion.

- Reduced Electricity Losses - Higher line loading tends to affect delivery losses more than average load, and managing this peak could lead to improvements in electricity delivery efficiency. If the customer is aware of their electricity use and shifts it to off-peak times, the losses may be reduced.

- Reduced CO2 Emissions – Increased customer awareness of electricity use may lead to conservation which, in turn would decrease the electricity generation required and the associated emissions. Furthermore, customer pricing and incentives can be used to optimize the load shape (especially at peak) leading increased system efficiency which will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

» Reduced SOx, NOx, and PM-2.5 Emissions – Increased customer awareness of electricity use may lead to conservation which, in turn would decrease the electricity generation required and the associated emissions. Furthermore, customer pricing and incentives can be used to optimize the load shape (especially at peak) leading increased system efficiency which will reduce the amount of generation required to serve load. Assuming that the generation is fossil-based, emissions will be reduced.

B.14 Distributed Production of Electricity

Distributed generation (DG), such as solar photovoltaic panels, are located on the distribution system, either on primary distribution feeders or behind the meter. DG supports economic, reliability, and environmental benefits depending on the resource type as shown in Table B-1.

Table B-1. Distributed Generation of Electricity Benefits

Resource Type	Benefits		
	Economic	Reliability	Environmental
Biomass (solid)	Yes	Yes	Maybe
Biomass (gaseous)	Yes	Yes	Maybe
Diesel	Yes	Yes	No
Geothermal	Yes	Yes	Yes
Natural Gas	Yes	Yes	No
PV	No	No	Yes
Wind	No	No	Yes

Economic Benefits

» Optimized Generator Operation – The ability of distributed generation to respond to changes in load could enable grid operators to run generators in their optimum operating zone. Operating distributed generation in this way can smooth the load curve that the generation fleet must meet. This benefit includes two components: (1) avoided generator start-up costs and (2) improved performance due to improved heat rate efficiency and load shaving.

» Deferred Generation Capacity Investments – Utilities build generation, transmission and distribution with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. DG can be used to reduce the amount of central station generation required during peak times. This should translate into lower infrastructure investments by utilities and cheaper electricity for customers.

» Reduced Ancillary Service Costs - The reserve margin is a required capacity above the peak demand that must be available and is typically +15% of peak demand. If peak demand is reduced, reserve margin would be reduced.

» Reduced Congestion Costs - DG provides energy closer to the end use, so less electricity must be passed through the congested transmission pathways, which reduces congestion.

» Deferred Transmission Capacity Investments - Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing generation capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.

» Deferred Distribution Capacity Investments - DG could be used to relieve load on overloaded feeders, potentially extending the time before upgrades or additions are required.

» Reduced Electricity Costs - DG could be used to reduce the cost of electricity during times when the price of "grid power" exceeds the cost of producing the electricity with DG. A consumer or the owner of an DG unit realizes savings on his electricity bill.

» Reduced Electricity Losses – Since DG is located closer to the load, it displaces grid power. Thus, power flow through distribution circuits and associated peak feeder losses, which are higher than at non-peak times, would be reduced.

Reliability Benefits

» Reduced Sustained Outages - The benefit to consumers is based on the value of service (VOS). Distributed generation could be used as a backup power supply for one or more customers until normal electric service could be restored.

Environmental Benefits

» Reduced CO_2 Emissions - Renewable energy provides electricity without net CO_2 emissions, reducing the emissions produced by fossil-based electricity generators. Furthermore, if DG is used to optimize net load shape to reduce electricity losses then the amount of generation required to serve load will be reduced. Assuming that the generation is fossil-based, emissions will be reduced as well.

» Reduced SO_X, NO_X, and PM-2.5 Emissions - Renewable energy provides electricity without net SO_X, NO_X, and PM-2.5 emissions produced by fossil-based electricity generators providing energy and peak demand. Furthermore, if DG is used to optimize net load shape to reduce electricity losses then the amount of generation required to serve load will be reduced. Assuming that the generation is fossil-based, emissions will be reduced as well.

B.15 Storing Electricity for Later Use

Electricity can be stored as chemical or mechanical energy and used later by consumers, utilities, or grid operators. In distributed applications, energy storage technologies most likely utilize inverter-based electrical interfaces that can produce real and reactive power. Depending on the capacity and stored energy of these devices, they can provide economic, reliability and environmental benefits. Stationary Energy Storage supports fourteen benefits.

» Optimized Generator Operation - The ability to respond to changes in load would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost, including the cost associated with polluting emissions. Electricity storage can be used to absorb generator output as electrical load decreases, allowing the generators to remain in their optimum operating zone. The stored electricity could then be used later so that dispatching additional, less efficient generation could be avoided. The storage can have the effect of smoothing the load curve that the generation fleet must meet. This benefit includes two components: (1) avoided generator start-up costs and (2) improved performance due to improved heat rate efficiency and load shaving.

» Deferred Generation Capacity Investments - Utilities build generation, transmission, and distribution with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. Electricity storage could be used to reduce the amount of central station generation required during peak times. This should translate into lower infrastructure investments by utilities and cheaper electricity for customers.

» Reduced Ancillary Services Cost - Ancillary services including spinning reserve and frequency regulation can be provided by energy storage resources. The reserve margin is a required capacity above the peak demand that must be available and is typically +15% of peak demand. If peak demand is reduced, reserve margin would be reduced.

» Reduced Congestion Cost - Distributed energy resources provide energy closer to the end use, so less electricity must be passed through the congested transmission pathways, which reduces congestion.

» Deferred Transmission Capacity Investments - Utilities build transmission with capacity sufficient to serve the maximum amount of load that planning forecasts indicate. The trouble is, this capacity is only required for very short periods each year, when demand peaks. Providing stored energy capacity closer to the load reduces the power flow on transmission lines, potentially avoiding or deferring capacity upgrades. This may be particularly effective during peak load periods.

» Deferred Distribution Capacity Investments - Electricity storage can also be used to relieve load on overloaded feeders, potentially extending the time before upgrades or additions are required.

» Reduced Electricity Losses - By managing peak feeder loads with electricity storage, peak feeder losses, which are higher than at non-peak times, would be reduced.

» Reduced Electricity Costs - Electricity storage can be used to reduce the cost of electricity, particularly during times when the price of "grid power" is very high. Consumers of energy or owners of enabled distributed energy resources (DER) realize savings on their electricity bill.

» Reduced Sustained Outages - Electricity storage can be used as a backup power supply for one or more customers until normal electric service can be restored. However, the backup would only be possible for a limited time (a few hours) depending on the amount of energy stored.

» Reduced Momentary Outages – When combined with the necessary control system, energy storage could act like an uninterruptible power supply (UPS), supporting end use load during a momentary outage.

- Reduced Sags and Swells – The same UPS capability could be used to smooth voltage sags and swells.

- Reduced CO_2 Emissions - Electricity storage can reduce electricity peak demand and thereby reduce feeder losses. This translates into a reduction in CO_2 emissions if peak load is typically produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall CO_2 emissions if fossil fuel generators are used for charging.

- Reduced SO_x, NO_x, and PM-2.5 Emissions - Electricity storage can reduce electricity peak demand and thereby reduce feeder losses. This translates into a reduction in emissions if peak load is typically produced by fossil-based electricity generators. However, since electricity storage has an inherent inefficiency associated with it, electricity storage could increase overall emissions if fossil fuel generators are used for charging.

- Reduced Oil Usage – If plug-in electric vehicles are utilized as grid storage assets, they can also provide the additional benefit of reduced oil usage. PEVs increase the fuel efficiency of vehicles by using electric energy stored in their batteries to power the vehicle as opposed to using oil based fuel. This fuel efficiency gain translates into a reduction in oil consumption per mile traveled.

Appendix C: Benefit and Cost Calculations

Table C-1presents the calculations and inputs required to monetize each of the benefits. The detailed methodology for quantifying and monetizing each benefit is further described below. In most cases, the benefit is determined by comparing the baseline value to the current value after implementing a smart grid project. The benefits in the table below are arranged according to how they appear in Table 3.

Table C-1. Summary of Benefit Input Parameters and Calculations

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Optimized Generator Operation	• Wide Area Monitoring, Visualization, & Control • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Annual Generation Cost ($) Optional Inputs • Average Hourly Generation Cost ($/MWh) • Avoided Annual Generator Dispatch (MWh) • Annual Energy Storage Efficiency (%) • Annual PEV Efficiency (%)	**Standard Calculation:** **Value ($)** = [Annual Generation Cost ($)]$_{Baseline}$ - [Annual Generation Cost ($)]$_{Project}$ **Optional Calculation:** **Value ($)** = [Average Hourly Generation Cost ($/MWh) * Avoided Annual Generator Dispatch (MWh) * Average Efficiency (%)]$_{Project}$ – [Average Hourly Generation Cost ($/MWh) * Avoided Annual Generator Dispatch (MWh) * Average Efficiency (%)]$_{Baseline}$ **Average Efficiency (%) =** For projects that yield this benefit as a result of Wide Area Monitoring, Visualization, and Control, the value will be 100%. For projects that just support Stationary Electricity Storage or Plug-in Electric Vehicles this value will be equal to the Annual Efficiency of these technologies. For projects that enable multiple functions that lead to this benefit an average of all efficiencies will be used.
Deferred Generation Capacity Investments	• Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Total Customer Peak Demand (MW) • Energy Storage Use at Annual Peak Time (MW) • Distributed Generation Use at Annual Peak Time (MW) – Impact • PEV Use at Annual Peak Time (MW) – Impact • Price of Capacity at Annual Peak ($/MW), Optional Inputs • Capital Carrying Charge of New Generation ($/yr) • Generation Investment Time Deferred (yrs)	**Standard Calculation:** **Value ($)** = [Price of Capacity at Annual Peak ($/MW) * {Total Customer Peak Demand (MW) – Energy Storage Use at Annual Peak Time (MW) – Distributed Generation Use at Annual Peak Time (MW) – PEV Use at Annual Peak Time (MW)}]$_{Baseline}$ - [Price of Capacity at Annual Peak ($/MW) * {Total Customer Peak Demand (MW) – Energy Storage Use at Annual Peak Time (MW) – Distributed Generation Use at Annual Peak Time (MW) – PEV Use at Annual Peak Time (MW)}]$_{Project}$ **Optional Calculation:** **Value ($)**= [Capital Carrying Charge of New Generation ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Project}$ - [Capital Carrying Charge of New Generation ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Baseline}$
Reduced Ancillary Service Cost	• Wide Area Monitoring Visualization and Control • Automated Voltage and VAR Control • Real-Time Load Measurement & Management • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles • Customer Electricity Use Optimization	• Ancillary Services Cost ($) Optional Inputs • Average Price of Reserves ($/MW) • Reserve Purchases (MW) • Average Price of Frequency Regulation ($/MW) • Frequency Regulation Purchases (MW) • Average Price of Voltage Control ($/MVAR) • Voltage Control Purchases (MVAR)	**Standard Calculation:** **Value ($) =** [Ancillary Services Cost ($)]$_{Baseline}$ - [Ancillary Services Cost ($)]$_{Project}$ **Optional Calculation:** **Value ($)** = [Σ (Price of Ancillary Service ($/MW) * Purchases (MW))]$_{Baseline}$ - [Σ (Price of Ancillary Service ($/MW) * Purchases (MW))]$_{Project}$
Reduced Congestion Cost	• Wide Area Monitoring, Visualization, & Control • Dynamic Capability Rating • Power Flow Control • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles • Customer Electricity Use Optimization	• Congestion Cost ($) Optional Inputs • Congestion (MW) • Average Price of Congestion ($/MW)	**Standard Calculation:** **Value ($)** = [Congestion Cost($)]$_{Baseline}$ - [Congestion Cost($)]$_{Project}$ **Optional Calculation:** **Value ($)** = [Congestion (MW) * Average Price of Congestion ($/MW)]$_{Baseline}$ - [Congestion (MW) * Average Price of Congestion ($/MW)]$_{Project}$

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Deferred Transmission Capacity Investments	• Fault Current Limiting • Wide Area Monitoring, Visualization, & Control • Dynamic Capability Rating • Power Flow Control • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Capital Carrying Charge of Transmission Upgrade ($) • Transmission Investment Time Deferred (yrs)	**Value ($)**= [Capital Carrying Charge of Transmission Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Project}$ - [Capital Carrying Charge of Transmission Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Baseline}$ Note: this should only be calculated once since all years of deferral are included
Deferred Distribution Capacity Investments	• Dynamic Capability Rating • Real-Time Load Measurement & Management • Real-Time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Capital Carrying Charge of Distribution Upgrade ($/yr) • Distribution Investment Time Deferred (yrs)	**Value ($)**= [Capital Carrying Charge of Distribution Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Project}$ - [Capital Carrying Charge of Distribution Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Baseline}$ Note: this should only be calculated once since all years of deferral are included
Reduced Equipment Failures	• Fault Current Limiting • Dynamic Capability Rating • Diagnosis & Notification of Equipment Condition • Enhanced Fault Protection	• Capital Replacement of Failed Equipment ($) • Portion Caused by Fault Current or Overloaded Equipment (%) • Portion Caused by Lack of Condition Diagnosis (%)	**For Fault Current Limiting, Dynamic Capability Rating, & Enhanced Fault Protection:** **Value ($)** = [Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%)]$_{Baseline}$ - [Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%)]$_{Project}$ **For Diagnosis & Notification of Equipment Condition:** **Value ($)** = [Capital Replacement of Failed Equipment ($) * Portion Caused by Lack of Condition Diagnosis (%)]$_{Baseline}$ - [Capital Replacement of Failed Equipment ($) * Portion Caused by Lack of Condition Diagnosis (%)]$_{Project}$
Reduced Transmission & Distribution Equipment Maintenance Cost	• Diagnosis & Notification of Equipment Condition	• Total Transmission Maintenance Cost ($) • Total Distribution Maintenance Cost ($)	**Value ($)** = [Total Distribution Equipment Maintenance Cost ($) + Total Transmission Equipment Maintenance Cost ($)]$_{Baseline}$ –[Total Distribution Equipment Maintenance Cost ($) + Total Transmission Equipment Maintenance Cost ($)]$_{Project}$
Reduced Transmission& Distribution Operations Cost	• Automated Feeder and Line Switching • Automated Voltage and VAR Control	• Transmission Operations Cost ($) • Distribution Operations Cost ($) Optional Inputs • Distribution Feeder Switching Operations ($) • Distribution Capacitor Switching Operations ($) • Other Distribution Operations Cost ($)	**Standard Calculation:** **Value ($)** = [Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Baseline}$ - [Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Project}$ **Optional Calculation**: **Value ($)** = [Distribution Feeder Switching Operations ($) + Distribution Capacitor Switching Operations ($) + Other Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Baseline}$ - [= Distribution Feeder Switching Operations ($) + Distribution Capacitor Switching Operations ($) + Other Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Project}$
Reduced Meter Reading Cost	• Real-Time Load Measurement & Management	• Meter Operations Cost ($)	**Value ($)** = [Meter Operations Cost ($)]$_{Baseline}$ - [Meter Operations Cost ($)]$_{Project}$

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Electricity Theft	• Real-Time Load Measurement & Management	• Number of Meter Tamper Detections – Residential • Number of Meter Tamper Detections – Commercial • Number of Meter Tamper Detections – Industrial • Average Annual Customer Electricity Usage – Residential, Commercial, Industrial	**Value ($)** = [Σ{ Number of Meter Tamper Detections by class (#) * Average Annual Customer Electricity Usage by class (kWh) * Average Percentage of Load not Measured by class (%) * Average Duration of Theft by class (% of year) * Average Retail Electricity Rate by class ($/kWh)}]$_{\text{Baseline}}$ - [Σ{ Number of Meter Tamper Detections by class (#) * Average Annual Customer Electricity Usage by class (kWh) * Average Percentage of Load not Measured by class (%) * Average Duration of Theft by class (% of year) * Average Retail Electricity Rate by class ($/kWh)}]$_{\text{Project}}$ **Average Percentage of Load not Measured by class (%)** = This is a DOE assumption that varies by class **Average Duration of Theft by class (% of year)** = This is a DOE assumption that varies by class **Average Retail Electricity Rate by class ($/kWh)** = Weighted Average of electricity rate by customer class
Reduced Electricity Losses	• Power Flow Control • Automated Voltage and VAR Control • Real-Time Load Measurement & Management • Real-Time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage	• Distribution Feeder Load (MW) • Distribution Losses (%) • Transmission Line Load (MW) • Transmission Losses (%) • Average Price of Wholesale Energy ($/MWh)	**Value ($)** = [(Distribution feeder load (MW) * Distribution losses (%) + Transmission line load (MW) * Transmission losses (%)) * 8760 (hr/yr)* Average Price of Wholesale Energy ($/MWh)]$_{\text{Baseline}}$ - [(Distribution feeder load (MW) * Distribution losses (%) + Transmission line load (MW) * Transmission losses (%)) * 8760 (hr/yr)* Average Price of Wholesale Energy ($/MWh)]$_{\text{Project}}$
Reduced Electricity Cost	• Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Total Residential Electricity Cost ($) • Total Commercial Electricity Cost ($) • Total Industrial Electricity Cost ($)	**Value ($)** = [Total Residential Electricity Cost ($) + Total Commercial Electricity Cost ($) + Total Industrial Electricity Cost ($)]$_{\text{Baseline}}$ - [Total Residential Electricity Cost ($) + Total Commercial Electricity Cost ($) + Total Industrial Electricity Cost ($)]$_{\text{Project}}$
Reduced Sustained Outages	• Adaptive Protection • Automated Feeder and Line Switching • Automated Islanding and Reconnection • Diagnosis & Notification of Equipment Condition • Enhanced Fault Protection • Real-Time Load Measurement & Management • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• SAIDI (System) • Value of Service (VOS) ($/kWh) – Residential, Commercial, Industrial • Average Hourly Load Not Served During Outage per Customer by class (kW) Optional Inputs • SAIDI (Impacted Feeders or Lines) • Total Customers Served by Impacted Feeders or Lines (#) – Residential, Commercial	**Standard Calculation:** **Value ($)** = Σ{ [SAIDI (System) * Total Customers Served within a class (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Baseline}}$ - [SAIDI (System) * Total Customers Served within a class (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Project}}$} **Optional Calculation:** **Value ($)** = Σ{ [SAIDI (Impacted Feeders or Lines) * Total Customers Served by Impacted Feeders or Lines (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Baseline}}$ - [SAIDI (Impacted Feeders or Lines) * Total Customers Served by Impacted Feeders or Lines (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Project}}$}
Reduced Major Outages	• Wide area Monitoring, Visualization & Control • Automated Islanding and Reconnection • Real-Time Load Measurement & Management • Real-Time Load Transfer	• Outage Time of Major Outage (hr) – Residential, Commercial, Industrial • Average Hourly Load Not Served During Outage per Customer by class (kW) • Value of Service (VOS) ($/kWh) – Residential, Commercial, Industrial	**Value ($)** = Σ{ [Outage Time of Major Outage by class(hr) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Baseline}}$ - [Outage Time of Major Outage by class(hr) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Project}}$}

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Restoration Cost	• Adaptive Protection • Automated Feeder and Line Switching • Automated Islanding and Reconnection • Diagnosis & Notification of Equipment Condition • Enhanced Fault Protection • Real-Time Load Measurement & Management	• Distribution Restoration Cost ($) • Transmission Restoration Cost ($) Optional Inputs • Number of Outage Events (#) • Restoration Cost per Event ($/event)	**Standard Calculation:** **Value ($)** = [Distribution Restoration Cost ($) + Transmission Restoration Cost ($)]$_{\text{Baseline}}$ - [Distribution Restoration Cost ($) + Transmission Restoration Cost ($)]$_{\text{Project}}$ **Optional Calculation:** **Value ($)** = [Number of Outage Events (# of events) * Restoration Cost per Event ($/event)]$_{\text{Baseline}}$ - [Number of Outage Events (# of events) * Restoration Cost per Event ($/event)]$_{\text{Project}}$
Reduced Momentary Outages	• Enhanced Fault Protection • Stationary Electricity Storage	• MAIFI (System) • Value of Service (VOS) – Power Quality ($/interruption) Optional Inputs • MAIFI (Impacted Feeders) • Total Customers Served on Impacted Feeders (momentary) (#) – Residential, Commercial, Industrial	**Standard Calculation:** **Value ($)** = [Momentary Interruptions (# of interruptions) * VOS – Power Quality ($ per interruption)]$_{\text{Baseline}}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{\text{Project}}$ Momentary Interruptions (# of interruptions) = MAIFI (Index) * Σ{Total Customers Served by class (#)} **Optional Calculation:** **Value ($)** = [Momentary Interruptions (# of interruptions) * VOS – Power Quality ($ per interruption)]$_{\text{Baseline}}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{\text{Project}}$ **Momentary Interruptions (# of interruptions)** = MAIFI of Impacted Feeders (Index) * Σ{Total Customers Served by class on the Impacted Feeders (#)}
Reduced Sags and Swells	• Enhanced Fault Protection • Stationary Electricity Storage	• Number of High Impedance Faults Cleared (# of events) • Value of Service (VOS) – Sags and Swells ($/event)	**Value ($)** = [Number of High Impedance Faults Cleared (# of events) * VOS – Sags and Swells ($/event)]$_{\text{Project}}$ - [Number of High Impedance Faults Cleared (# of events) * VOS – Sags and Swells ($/event)]$_{\text{Baseline}}$

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced CO_2 Emissions	• Power Flow Control • Automated Feeder and Line Switching • Automated Voltage and VAR Control • Diagnosis & Notification of Equipment Condition • Real-Time Load Measurement & Management • Real-time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	**<u>For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition</u>** • Truck Rolls (# of events) • Average Miles Travelled per Truck Roll (miles/event) • Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile) • CO_2 Emissions per Gallon of Fuel(tons/gallon) **<u>Optional Inputs</u>** • Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading **<u>For PEV with Reduced Gasoline Consumption Mechanism</u>** • kWh of Electricity Consumed by PEVs (kWh) • Electricity to Fuel Conversion Factor (gallons/kWh) **<u>For all other Functions (Including PEV with Offset Central Generation Mechanism)</u>** • CO_2 Emissions (tons) • Value of CO_2 ($/ton)	**Value ($)** = Σ{Net CO2 Emissions Avoided (tons)}* Value of CO2 ($/ton) **Net CO2 Emissions Avoided (tons)** = $[CO_2 \text{ Emissions (tons)}]_{Baseline}$ - $[CO_2 \text{ Emissions (tons)}]_{Project}$ **Net CO2 Emissions Avoided (tons) =** $[\text{CO2 Emissions Avoided(tons)}]_{Project}$ - $[\text{CO2 Emissions Avoided (tons)}]_{Baseline}$ **<u>For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition:</u>** **CO2 Emissions (tons)** = Truck Rolls (# of events) * Average Miles Travelled per Truck Roll (miles/event) ÷ Average Fuel Efficiency for Truck Roll Vehicle (miles/gallon) * CO2 Emissions per Gallon of Fuel (tons/gallon) **<u>Optional Calculation:</u>** **CO2 Emissions (tons)** = Σ{Number of Operations Completed(# of events) * Average Miles Traveled per Operation (miles/event) ÷ Average Fuel Efficiency for Service Vehicle (miles/gallon)} * CO2 Emissions per Gallon of Fuel (tons/gallon) **<u>For PEV with Reduced Gasoline Consumption Mechanism:</u>** **CO2 Emissions Avoided (tons)** = kWh of Electricity Consumed by PEVs (kWh) * Electricity to Fuel Conversion Factor (gallons/kWh) * CO2 Emissions per Gallon of Fuel (tons/gallon) **<u>For all other Functions (Including PEV with offset central generation):</u>** **CO2 Emissions (tons)** = Calculated and reported by the project directly.

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced SO_x, NO_x, and PM-2.5 Emissions	• Power Flow Control • Automated Feeder and Line Switching • Automated Voltage and VAR Control • Diagnosis & Notification of Equipment Condition • Real-Time Load Measurement & Management • Real-time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	**For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition** • Truck Rolls (# of events) • Average Miles Travelled per Truck Roll (miles/event) • Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile) • Emissions per Gallon of Fuel(tons/gallon) – SO_x, NO_x **Optional Inputs** • Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading **For PEV with Reduced Gasoline Consumption Mechanism** • kWh of Electricity Consumed by PEVs (kWh) • Electricity to Fuel Conversion Factor (gallons/kWh) **For all other Functions (Including PEV with Offset Central Generation Mechanism)** • SOx Emissions (tons) • NOx Emissions (tons) • PM-2.5 Emissions (tons) • Value of Emissions ($/ton) – SO_x, NO_x, PM-2.5	**Value ($)** = Σ{Net Emissions Avoided (tons)* Value of Emissions ($/ton)} **Net Emissions Avoided (tons)** = $[\text{Emissions (tons)}]_{\text{Baseline}} - [\text{Emissions (tons)}]_{\text{Project}}$ **Net Emissions Avoided (tons) =** $[\text{Emissions Avoided(tons)}]_{\text{Project}} - [\text{Emissions Avoided (tons)}]_{\text{Baseline}}$ **For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition:** **Emissions (tons)** = Truck Rolls (# of events) * Average Miles Travelled per Truck Roll (miles/event) ÷ Average Fuel Efficiency for Truck Roll Vehicle (miles/gallon) * Emissions per Gallon of Fuel (tons/gallon) **Optional Calculation:** **Emissions (tons)** = Σ{Number of Operations Completed(# of events) * Average Miles Traveled per Operation (miles/event) ÷ Average Fuel Efficiency for Service Vehicle (miles/gallon)} * Emissions per Gallon of Fuel (tons/gallon) **For PEV with Reduced Gasoline Consumption Mechanism:** **Emissions Avoided (tons)** = kWh of Electricity Consumed by PEVs (kWh) * Electricity to Fuel Conversion Factor (gallons/kWh) * Emissions per Gallon of Fuel (tons/gallon) **For all other Functions (Including PEV with offset central generation):** **Emissions (tons)** = Calculated and reported by the project directly.

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Oil Usage	• Automated Feeder and Line Switching • Diagnosis & Notification of Equipment Condition • Real-Time Load Measurement & Management • Plug-in Electric Vehicles	<u>**For PEVs (with reduced gasoline consumption mechanism):**</u> • kWh of Electricity Consumed by PEVs (kWh) • Electricity to Fuel Conversion Factor (gallons/kWh) <u>**For all other Functions**</u> • Truck Rolls (# of events) • Average Miles Travelled per Truck Roll (miles/event) • Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile) <u>**Optional Inputs**</u> • Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading	**Value (gallons of oil)** = Net Avoided Fuel Use (gallons)* Fuel to Oil Conversion Factor (gallons oil/gallon fuel) **Net Avoided Fuel Use (gallons)** = [Fuel Use (gallons)]$_{Baseline}$ - [Fuel Use (gallons)]$_{Project}$ **Net Avoided Fuel Use (gallons) =** [Avoided Fuel Use (gallons)]$_{Project}$ - [Avoided Fuel Use (gallons)]$_{Baseline}$ <u>**For PEVs (with reduced gasoline consumption mechanism):**</u> **Avoided Fuel Use (gallons)** = kWh of Electricity Consumed by PEVs (kWh) * Electricity to Fuel Conversion Factor (gallons/kWh) <u>**For all other Functions:**</u> **Fuel Use (gallons)** = Truck Rolls (# of events) * Average Miles Travelled per Truck Roll (miles/event) ÷ Average Fuel Efficiency for Truck Roll Vehicle (miles/gallon) <u>**Optional Calculation:**</u> **Fuel Use (gallons) =** Σ{Number of Operations Completed(# of events) * Average Miles Traveled per Operation (miles/event) ÷ Average Fuel Efficiency for Service Vehicle (miles/gallon)}
Reduced Wide-scale Blackouts	• Wide Area Monitoring & Visualization • Dynamic Capability Rating	• Number of Wide-scale Blackouts (# of events) • Estimated Cost of each Wide-scale Blackout ($/event)	**Value ($)** = [Number of Wide-scale Blackouts (# of events) * Estimated Cost of each Wide-scale Blackout ($/event)]$_{Baseline}$ - [Number of Wide-scale Blackouts (# of events) * Estimated Cost each Wide-scale Blackout ($/event)]$_{Project}$

C.1 Optimized Generator Operation

The Optimized Generator Operation benefit can be realized through three functions:

- Wide Area Monitoring, Visualization, and Control
- Distributed Production of Electricity
- Storing Electricity for Later Use

Better forecasting and monitoring of load and grid performance through a smart grid would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost. The Optimized Generator Operation benefit is composed of two pieces: avoided generator start-up costs and improved performance due to improved heat rate efficiency. The coordinated operation of energy storage or plug-in electric vehicle assets could also result in completely avoiding central generation dispatch. In order to determine the value of the benefit, the project would have to track the total Annual Generation Cost or the Avoided Annual Generator Dispatch (MWh), along with the Average Hourly Generation Cost($/MWh). The standard calculation to monetize the impact of this benefit utilizes the following formula:

Value ($) = [Annual Generation Cost ($))]$_{\text{Baseline}}$ – [Annual Generation Cost ($)]$_{\text{Project}}$

The optional calculation to monetize the impact of this benefit utilizes the following formula:

**Value ($)** = {[Average Hourly Generation Cost ($/MWh) * Avoided Annual Generator Dispatch (MWh)]$_{\text{Baseline}}$ – Average Hourly Generation Cost ($/MWh) * Avoided Annual Generator Dispatch (MWh)]$_{\text{Project}}$} * Average Efficiency(%)

> **Average Efficiency (%) =** For projects that yield this benefit as a result of Wide Area Monitoring, Visualization, and Control, the value will be 100%. For projects that just support Stationary Electricity Storage or Plug-in Electric Vehicles this value will be equal to the Annual Efficiency of these technologies. For projects that enable multiple functions which lead to this benefit an average of all efficiencies will be used.

Optimized generator operation could be very difficult to track and monetize because of the relatively small size of the project and the necessary coordination with the grid operator. The contribution to the optimized generator operation benefit will likely have to be estimated, rather than calculated. In this case, the value could be based on the reduction in marginal generation that could be realized if generators could follow load more closely or if electricity storage or PEVs could provide ancillary services so that conventional generators could operate at a more optimal level.

C.2 Deferred Generation Capacity Investments

The Deferred Generation Capacity Investments benefit can be realized through three functions:

- Customer Electricity Use Optimization
- Distributed Production of Electricity
- Storing Electricity for Later Use

The impact of this benefit is determined by the capacity of the DG or energy storage (MW) and/or the amount of load reduction from customer optimization (MW) and the price paid for capacity ($/MW), which represents the capital expenditures for conventional generation. The project would report when the EER was utilized during peak times. The Total Customer Peak Demand should already include any impacts from energy efficiency, demand response programs, or any other programs and technology that results in customer electricity use optimization. The monetary impact of this benefit is calculated using the following formula:

Value ($) = [Price of Capacity at Annual Peak ($/MW) * Total Customer Peak Demand (MW) – Energy Storage Use at Annual Peak Time (MW) – Distributed Generation Use at Annual Peak Time (MW) – PEV Use at Annual Peak Time (MW)]$_{\text{Baseline}}$ - [Price of Capacity at Annual Peak ($/MW) * Total Customer Peak Demand (MW) – Energy Storage Use at Annual Peak Time (MW) – Distributed Generation Use at Annual Peak Time (MW) – PEV Use at Annual Peak Time (MW)]$_{\text{Project}}$

This assumes the price of the marginal unit at peak and that generation deferral is based on reducing peak demand. If the project EER is not available during the peak time, no benefit is derived from those assets. Alternatively, the benefit could be monetized based on the value of deferring a central generating plant.

Value ($) = [NPV of Generation Investment Deferral($)]$_{\text{project}}$- [NPV of Generation Investment Deferral ($)]$_{\text{baseline}}$

> **NPV of Generation Investment Deferral ($)** = Capital Carrying Charge of New Generation ($) *[1-(1-discount rate (%))^Time Deferred (yrs)]

C.3 Reduced Ancillary Service Cost

The Reduced Ancillary Service Cost benefit can be realized through six functions:

- Wide Area Monitoring and Visualization
- Automated Voltage and VAR Control
- Real-Time Load Measurement & Management
- Customer Electricity Use Optimization
- Distributed Production of Electricity
- Storing Electricity for Later Use

These smart grid functions and EERs could enable grid operators to procure ancillary services from sources other than conventional generators at a reduced cost, or to reduce the amount required to operate without sacrificing reliability. The standard calculation simply tracks total annual ancillary service cost:

Value ($) = [Ancillary Service Cost ($)]$_{\text{Baseline}}$ - [Ancillary Service Cost ($)]$_{\text{Project}}$

Using an Optional Calculation the project would track the value derived from reducing the cost of three types of ancillary services: reserves, frequency regulation, and voltage control.

Value ($) = [Σ (Price of Ancillary Service ($/MW) * Purchases (MW))]$_{\text{Baseline}}$ - [Σ (Price of Ancillary Service ($/MW) * Purchases (MW))]$_{\text{Project}}$

This benefit will be hard for a project to track because ancillary services vary significantly from year to year and are market based, so it may be impossible to establish a baseline. It would also require coordination with the grid operators.

C.4 Reduced Congestion Cost

The Reduced Congestion Cost benefit can be realized through six functions:

- Wide Area Monitoring, Visualization, and Control
- Dynamic Capability Rating
- Power Flow Control
- Customer Electricity Use Optimization
- Distributed Production of Electricity
- Storing Electricity for Later Use

For the Standard Calculation, the project would track Annual Congestion Costs. The monetary impact of this benefit is calculated using the following formula:

Value ($) = [Congestion Cost($)]$_{Baseline}$ - [Congestion Cost($)]$_{Project}$

For the Optional Calculation, the project would report the hourly congestion relief provided by the function or EER along with the cost of congestion during the hours of operation, as shown in Table C-2. To monetize this benefit, the relief (MW) is multiplied by the typical congestion price. For example, assume a transmission line had a normal summer rating of 1,000 MW based on typical summer day air temperatures and wind speed. On a cooler than normal day, with breezy conditions, the rating of the line might be increased during a critical mid-day peak to 1,100 MW, potentially relieving congestion. The project could report that the dynamic rating relieved 100 MW of congestion for two hours. Therefore, the amount of congestion in the project scenario is zero and the congestion relief represents the baseline amount of congestion that would have taken place had dynamic ratings not been implemented in the baseline build-out of the grid. To monetize this benefit the congestion relief is multiplied by the average or typical congestion price according to the following formula:

Value ($) = [Congestion (MW) * Price of Congestion ($/MW)]$_{Baseline}$ - [Congestion (MW) * Price of Congestion ($/MW)]$_{Project}$

Table C-2. Means of Congestion Relief

Function	Means of Congestion Relief
Dynamic Capability Rating	Increase in rating of congested system element
Power Flow Control	Avoidance of overloading congested system element
Customer Electricity Use Optimization	Reduction in loading on congested system element
Distributed Production of Electricity	Reduction in loading on congested system element
Stationary Electricity for Later Use	Reduction in loading on congested system element

C.5 Deferred Transmission Capacity Investment

The Deferred Transmission Capacity Investments benefit can be realized through seven functions:

- Fault Current Limiting
- Wide Area Monitoring, Visualization, and, Control
- Dynamic Capability Rating

- » Power Flow Control
- » Customer Electricity Use and Optimization
- » Distributed Production of Electricity
- » Storing Electricity for Later Use

For Fault Current Limiting, a project could report the deferred cost of replacing or upgrading circuit breakers or other transmission and distribution equipment.

For Wide Area Monitoring, Visualization, and Control, a project could report the increase in transmission capability that resulted from better operating information. This increased capability could be related to a deferred upgrade.

For Dynamic Capability Rating, the project could track the dynamic hourly ratings of system elements and compare these to standard (fixed) ratings. In cases where the dynamic rating exceeded the standard rating, the project could multiply the additional capacity by the typical carrying charge and the time for which the upgrade could be deferred.

For Power Flow Control, the project would track the amount of power that power flow control diverted to another system element (e.g., 100 MW diverted to anther transmission line), and the estimated cost of the project that the additional capacity deferred ($/MW).

The use of customer optimization or distributed generation, or energy storage could decrease the loading on transmission system elements and postpone the need for capital upgrades. The project would reduce the capacity (MW) needed during peak times, which would lead to deferral of equipment or line upgrades.

Value ($) = [NPV of Transmission Investment Deferral ($)]$_{project}$- [NPV of Transmission Investment Deferral ($)]$_{baseline}$

> **NPV of Transmission Investment Deferral ($)** = Capital Carrying Charge of Transmission Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))

For each these benefits, the deferred cost could be accumulated over time. For example, a project could be deferred for one year, and then the following year it could be deferred again, depending on loading and the dynamic rating.

C.6 Deferred Distribution Capacity Investment

The Deferred Distribution Capacity Investment benefit can be realized through six functions:

- Dynamic Capability Rating
- Real-Time Load Measurement and Management
- Real-Time Load Transfer
- Customer Electricity Use and Optimization
- Distributed Production of Electricity
- Storing Electricity for Later Use

For Dynamic Capability Rating, the project could report the dynamic hourly ratings of system elements and compare these to standard (fixed) ratings. In cases where the dynamic rating exceeded the standard rating, the project could multiply the additional capacity by the typical carrying charge and the time for which the upgrade could be deferred.

Real-Time Load Transfer and the use of EERs (DG, ES, and PEV) could decrease the loading on distribution system elements and postpone the need for capital upgrades.

For Real-Time Load Measurement and Management, the project would report the capital upgrade schedule for infrastructure associated with the project. Based on better monitoring, they could identify projects that can be deferred as a result of being able to operate closer to the feeder limit.

The use of customer optimization, distributed generation, or energy storage could decrease the loading on distribution system elements and postpone the need for capital upgrades. The project would reduce the capacity (MW) needed during peak times, which would lead to deferral of equipment or line upgrades.

Value ($) = [NPV of Distribution Investment Deferral ($)]$_{project}$- [NPV of Distribution Investment Deferral ($)]$_{baseline}$

> **NPV of Transmission Investment Deferral ($)** = Capital Carrying Charge of Distribution Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))

C.7 Reduced Equipment Failures

The Reduced Equipment Failures benefit can be realized through four functions:

- Fault Current Limiting
- Dynamic Capability Rating
- Diagnosis and Notification of Equipment Condition
- Enhanced Fault Protection

For Fault Current Limiting, Dynamic Capability Rating, and Enhanced Fault Protection, projects would report the capital expenditures related to equipment failure within the project scope, and apply an estimate of the impact of fault current or overloading. The following formula will be used to calculate the monetary value of this benefit:

Value ($) = [Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%)]$_{Baseline}$ - [Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%)]$_{Project}$

For Diagnosis and Notification of Equipment Condition, the cost of the equipment that did not have to be replaced must be estimated. This could be done either by the project, or by the DOE. The estimate could be based on a utility’s annual capital budget for equipment replacement, and the utility’s estimate of how much of that capital budget is spent on replacing equipment that could have been prevented with timely diagnosis and maintenance. A portion of that cost could be allocated to the project on a pro rata basis. The value is calculated with the following formula:

Value ($) = [Capital Replacement of Failed Equipment ($) * Portion Caused by Lack of Condition Diagnosis (%)]$_{Baseline}$ - [Capital Replacement of Failed Equipment ($) * Portion Caused by Lack of Condition Diagnosis (%)]$_{Project}$

C.8 Reduced Transmission and Distribution Equipment Maintenance Cost

The Reduced Transmission and Distribution Equipment Maintenance Cost benefit can be realized through one function:

» Diagnosis and Notification of Equipment Condition

To calculate this benefit, the project would track the cost of transmission and distribution equipment maintenance before and after the project. The monetary impact of this benefit is calculated using the following formula:

Value ($) = [Total Distribution Equipment Maintenance Cost ($) + Total Transmission Equipment Maintenance Cost ($)]$_{Baseline}$ –[Total Distribution Equipment Maintenance Cost ($) + Total Transmission Equipment Maintenance Cost ($)]$_{Project}$

C.9 Reduced Transmission and Distribution Operations Cost

The Reduced Transmission and Distribution Operations Cost benefit can be realized through two functions:

» Automated Feeder and Line Switching
» Automated Voltage and VAR Control

The project would track the cost associated with transmission and distribution operations after implementation of the smart grid project compared to the operations cost prior to implementing the project.

The standard calculation to monetize the impact of this benefit utilizes the following formula:

Value ($) = [Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Baseline}$ - [Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Project}$

An optional calculation which breaks out cost of the feeder, line, and capacitor switching operations can also be used to monetize the impact of this benefit.

Value ($) = [Distribution Feeder Switching Operations ($) + Distribution Capacitor Switching Operations ($) + Other Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Baseline}$ - [= Distribution Feeder Switching Operations ($) + Distribution Capacitor Switching Operations ($) + Other Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Project}$

These costs can be tracked through an activity based costing system or Work Management System (WMS). If it is not possible for the project to track and report the necessary information, the impact of this benefit can be determined by estimating the percentage of a field crew's time is dedicated to switching, and then estimating the time saved by the field service personnel compared to before implementing the smart grid project.

C.10 Reduced Meter Reading Cost

The Reduced Meter Reading Cost benefit can be realized through one function:

» Real-Time Load Measurement & Management

The project would report the total annual meter operations costs. The baseline meter operations cost can be calculated by tracking the number of meters to be read remotely and multiplying this number by the average cost to manually read a meter.

Value ($) = $[\text{Meter Operations Cost (\$)}]_{\text{Baseline}}$ - $[\text{Meter Operations Cost (\$)}]_{\text{Project}}$

Alternatively, the project could directly report the metering reading costs that were eliminated.

C.11 Reduced Electricity Theft

The Reduced Electricity Theft benefit can be realized through one function:

» Real-Time Load Measurement & Management

The project would report the number of electricity theft events detected. The monetary impact of this benefit is calculated using the following formula:

**Value ($)** = [Σ{ Number of Meter Tamper Detections by class (#) * Average Annual Customer Electricity Usage by class (kWh) * Average Percentage of Load not Measured by class (%) * Average Duration of Theft by class (% of year) * Average Retail Electricity Rate by class ($/kWh)}]$_{\text{Baseline}}$ - [Σ{ Number of Meter Tamper Detections by class (#) * Average Annual Customer Electricity Usage by class (kWh) * Average Percentage of Load not Measured by class (%) * Average Duration of Theft by class (% of year) * Average Retail Electricity Rate by class ($/kWh)}]$_{\text{Project}}$

The Average Duration of Theft parameter captures the idea that the electricity theft may not take place for all hours of the year. The Average Percentage of Load not Measured parameter captures the idea that a customer may only be stealing a portion of the electricity that they are using. Both of these parameters are estimated by the DOE.

Projects will be responsible for reporting incidents of theft detected by AMI. Smart meters will log hourly usage and this hourly usage data can be used to compile typical hourly usage curves for customer classes or sub-classes. However, the probability of identifying electricity theft within a pilot project could be low. Projects will also be responsible for estimating what the average annual customer electricity usage is for each customer class.

C.12 Reduced Electricity Losses

The Reduced Electricity Losses benefit can be realized through seven functions:

» Power Flow Control
» Automated Voltage and VAR control
» Real-Time Load Measurement & Management
» Real-Time Load Transfer
» Customer Electricity Use Optimization

- Distributed Production of Electricity
- Storing Electricity for Later Use

The best approach for determining loss reductions for a project is to make coincident measurements on the portion of the delivery system incurring the losses. For example, if a project were seeking to demonstrate a loss reduction on a distribution feeder, the hourly load and voltage data from smart meters, as well as hourly load and voltage data from the head end of the feeder at the substation could be measured, and the data used to calculate the losses. The impact of this benefit is calculated with the following formula:

Value ($) = [(Distribution feeder load (MW) * Distribution losses (%) + Transmission line load (MW) * Transmission losses (%)) * 8760 (hr/yr)* Average Price of Wholesale Energy ($/MWh)]$_{\text{Baseline}}$ - [(Distribution feeder load (MW) * Distribution losses (%) + Transmission line load (MW) * Transmission losses (%)) * 8760 (hr/yr)* Average Price of Wholesale Energy ($/MWh)]$_{\text{Project}}$

The feeder and line load inputs of the above equation represent the average load, and the losses inputs represent the average losses as a percentage of the average load.

Several functions can contribute to reducing losses, and projects demonstrating more than one of these functions at one time will see compounded effects.

C.13 Reduced Electricity Cost

The Reduced Electricity Cost benefit can be realized through three functions:

- Customer Electricity Use Optimization
- Distributed Production of Electricity
- Storing Electricity for Later Use

The project would record and report total customer electricity costs and the impact of this benefit will be monetized using the following formula:

Value ($) = [Total Residential Electricity Cost ($) + Total Commercial Electricity Cost ($) + Total Industrial Electricity Cost ($)]$_{\text{Baseline}}$ - [Total Residential Electricity Cost ($) + Total Commercial Electricity Cost ($) + Total Industrial Electricity Cost ($)]$_{\text{Project}}$

This benefit can gauge if the smart grid technologies are successful in enabling reductions in customer electricity consumption and demand.

C.14 Reduced Sustained Outages

The Reduced Sustained Outages benefit can be realized through eight functions:

- Adaptive Protection
- Automated Feeder and Line Switching
- Automated Islanding and Reconnection
- Diagnosis & Notification of Equipment Condition
- Enhanced Fault Protection
- Real-Time Load Measurement and Management

- Distributed Production of Electricity
- Storing Electricity for Later Use

Accurate values of the System Average Interruption Duration Index (SAIDI) could be calculated using smart meter data or outage management systems. This reliability index would then be used to determine the total hours of outages customers experienced. The user is responsible for estimating the average hourly load not served during an outage for each customer class. By applying a value of service (VOS) metric (i.e., by customer class), the value of the energy not served can be estimated as follows:

**Value ($)** = Σ{ [SAIDI (System) * Total Customers Served within a class (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{Baseline}$ - [SAIDI (System) * Total Customers Served within a class (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{Project}$}

Depending on the sophistication of the AMI and outage management system, or on the scope of the smart grid application that will lead to reliability improvements, SAIDI could be calculated and reported for a subset of feeders or lines rather than for the entire system. This would allow the impact of the smart grid technology to be determined more precisely. The total number of customers served by that subset of feeders or lines would be reported as well and the load not served would be calculated as before. These inputs can be used to monetize the impact of this benefit with the following formula:

**Value ($)** = Σ{ [SAIDI (Impacted Feeders or Lines) * Total Customers Served by Impacted Feeders or Lines (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{Baseline}$ - [SAIDI (Impacted Feeders or Lines) * Total Customers Served by Impacted Feeders or Lines (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{Project}$}

C.15 Reduced Major Outages

The Reduced Major Outages benefit can be realized through four functions:

- Wide Area Monitoring, Visualization, and Control
- Automated Islanding and Reconnection
- Real-Time Load Measurement and Management
- Real-Time Load Transfer

As with Reduced Sustained Outages, to calculate the Reduced Major Outages benefit smart meters would log outage times and this would be multiplied by a VOS metric. The user is responsible for providing an estimate of the average load not served per customer class.

**Value ($)** = Σ{ [Outage Time of Major Outage by class(hr) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{Baseline}$ - [Outage Time of Major Outage by class(hr) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{Project}$}

Major outage events are distinguished from sustained outage events in that major outage events are unplanned events that are not included in reliability index calculations.

C.16 Reduced Restoration Cost

The Reduced Restoration Cost benefit can be realized through four functions:

- Adaptive Protection
- Automated Feeder and Line Switching
- Automated Islanding and Reconnection
- Diagnosis & Notification of Equipment Condition
- Enhanced Fault Protection
- Real-Time Load Measurement & Management

The project could report and track the number of outages and the reduction in restoration costs achieved by being able to restore service more quickly. Over the course of the project, the utility would track outages and the result would be compared against the baseline. Two equations can be used to monetize this benefit. In the standard equation, distribution and transmission restoration costs are tracked and input directly.

Value ($) = [Distribution Restoration Cost ($) + Transmission Restoration Cost ($)]$_{\text{Baseline}}$ - [Distribution Restoration Cost ($) + Transmission Restoration Cost ($)]$_{\text{Project}}$

In the optional calculation, the number of outages and an estimate of the restoration costs per event are tracked and input to an equation. This equation allows for the impact of a smart grid project on restoration costs to be calculated more precisely, since individual events and the costs of those events could be tracked and input separately.

Value ($) = [Number of Outage Events (# of events) * Restoration Cost per Event ($/event)]$_{\text{Baseline}}$ - [Number of Outage Events (# of events) * Restoration Cost per Event ($/event)]$_{\text{Project}}$

C.17 Reduced Momentary Outages

The Reduced Momentary Outages benefit can be realized through two functions:

- Enhanced Fault Protection
- Storing Electricity for Later Use

The value of this benefit is based on the VOS metrics which are typically determined by customer class (residential, commercial, industrial) and may vary geographically. The VOS metric for this benefit is specifically related to power quality and momentary outages. The SGCT contains default VOS values that can be used, but VOS values that are specific to an operating territory can also be used and are recommended. Customer momentary interruptions could be logged by smart meters or outage management systems. The metric for momentary interruptions would most likely be the Momentary Average Interruption Frequency Index (MAIFI) for the project. The MAIFI index could be tracked for the entire service territory or it could be tracked only for the part of the service territory in which smart grid technology is expected to have an impact on momentary outages. The standard calculation utilizes the system MAIFI while the optional calculation utilizes the more targeted MAIFI value.

The standard calculation to monetize the impact of this benefit utilizes the following formula:

Value ($) = [Momentary Interruptions (# of interruptions) * VOS – Power Quality ($ per interruption)]$_{Baseline}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{Project}$

Momentary Interruptions (# of interruptions) = MAIFI (Index) * Σ{Total Customers Served by class (#)}

The optional calculation to monetize the impact of this benefit utilizes the following formula:

Value ($) = [Momentary Interruptions (# of interruptions) * VOS – Power Quality ($ per interruption)]$_{Baseline}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{Project}$

Momentary Interruptions (# of interruptions) = MAIFI of Impacted Feeders (Index) * Σ{Total Customers Served by class on the Impacted Feeders (#)}

C.18 Reduced Sags and Swells

The Reduced Sags and Swells benefit can be realized through two functions:

» Enhanced Fault Protection
» Storing Electricity for Later Use

The project would track the number of high impedance faults that were cleared without causing voltage sags. Feeder monitoring will most likely be required to determine the number and severity of voltage sags since customers do not always detect these events, and most probably go unreported.

Value ($) = [Number of High Impedance Faults Cleared (# of events) * VOS – Sags and Swells ($/event)]$_{Baseline}$ - [Number of High Impedance Faults Cleared (# of events) * VOS – Sags and Swells ($/event)]$_{Project}$

VOS would be for voltage sag and swell events, and is probably most applicable to customers with sensitive loads. The project or DOE will estimate the VOS associated with voltage variations, and could refer to IEEE 1159[7] or a similar guideline to determine the technical impact of these events and calculate the value.

C.19 Reduced CO_2 Emissions

The Reduced CO_2 Emissions benefit can be realized through nine functions:

» Power Flow Control
» Automated Feeder and Line Switching
» Automated Voltage and VAR Control
» Diagnosis & Notification of Equipment Condition
» Real-Time Load Measurement & Management
» Real-time Load Transfer
» Customer Electricity Use Optimization
» Distributed Production of Electricity
» Storing Electricity for Later Use

[7] IEEE Std 1159-1995 IEEE Recommended Practice for Monitoring Electric Power Quality

For the three functions Automated Feeder and Line Switching, Diagnosis & Notification of Equipment Condition, and Real Time Load Measurement and Management, the impact of this benefit is based on reducing truck rolls for operations and maintenance, and meter reading. The project would track the number and distance of truck rolls for typical distribution operations activities. The average fuel efficiency of the vehicles would be reported and the emissions associated with using fuel for truck rolls would then be determined.[8]

CO2 Emissions (tons) = Truck Rolls (# of events) * Average Miles Travelled per Truck Roll (miles/event) ÷ Average Fuel Efficiency for Truck Roll Vehicle (miles/gallon) * CO2 Emissions per Gallon of Fuel (tons/gallon)

Alternatively the truck rolls for each of these different activities could be tracked and reported separately, and the emissions would be calculated separately as well using the following formula:

CO2 Emissions (tons) = Σ{Number of Operations Completed(# of events) * Average Miles Traveled per Operation (miles/event) ÷ Average Fuel Efficiency for Service Vehicle (miles/gallon)} * CO2 Emissions per Gallon of Fuel (tons/gallon)

For the five functions Power Flow Control, Automated Voltage and VAR Control, Customer Electricity Use Optimization, Storing Electricity for Later Use, and Distributed Production of Electricity, the reduction is due to reducing the amount of central generation needed to meet demand. More specifically, the reduction in emissions is associated with reducing peak demand and reducing the use of central generation. Therefore, the emissions associated with central generation would have to be determined for each project based on the generation mix in the service territory of the project. The emissions (or emissions avoided) would then be reported directly.

CO2 Emissions (tons) = Calculated and reported by the project directly.

If PEVs are being used as service vehicles, or being deployed throughout the service territory as part of studies, there will be an avoided CO2 emissions benefit associated with the electricity that these vehicles use instead of burning fuel. This avoided CO2 is calculated using the following formula:

CO2 Emissions Avoided (tons) = kWh of Electricity Consumed by PEVs (kWh) * Electricity to Fuel Conversion Factor (gallons/kWh) * CO2 Emissions per Gallon of Fuel (tons/gallon)

All of these sources of emissions and avoided emissions values would be aggregated for a particular project and monetized according to the following formulae:

**Value ($)** = Σ{Net CO2 Emissions Avoided (tons)}* Value of CO2 ($/ton)

Net CO2 Emissions Avoided (tons) = $[CO_2 \text{ Emissions (tons)}]_{Baseline}$ - $[CO_2 \text{ Emissions (tons)}]_{Project}$

Net CO2 Emissions Avoided (tons) = $[\text{CO2 Emissions Avoided(tons)}]_{Project}$ - $[\text{CO2 Emissions Avoided (tons)}]_{Baseline}$

C.20 Reduced SOx, NOx, and PM-2.5 Emissions

The benefit of reducing SOx, NOx and PM-2.5 emissions benefit can be realized through nine functions:

[8] EPA reports 19.4 lbs CO2 per gallon of gasoline.

» Power Flow Control
» Automated Feeder and Line Switching
» Automated Voltage and VAR Control
» Diagnosis & Notification of Equipment Condition
» Real-Time Load Measurement & Management
» Real-time Load Transfer
» Customer Electricity Use Optimization
» Distributed Production of Electricity
» Storing Electricity for Later Use

As with CO_2 reductions, the impact of this benefit for Automated Feeder and Line Switching, Diagnosis & Notification of Equipment Condition, and Real Time Load Measurement and Management is based on reducing truck rolls for operations and maintenance. The equations for quantifying the emissions from these sources are similar.

Emissions (tons) = Truck Rolls (# of events) * Average Miles Travelled per Truck Roll (miles/event) ÷ Average Fuel Efficiency for Truck Roll Vehicle (miles/gallon) * Emissions per Gallon of Fuel (tons/gallon)

If the project wants to track the number of truck rolls, average miles traveled, and average fuel efficiency of the vehicles for each activity separately the following formula would be used:

Emissions (tons) = Σ{Number of Operations Completed(# of events) * Average Miles Traveled per Operation (miles/event) ÷ Average Fuel Efficiency for Service Vehicle (miles/gallon)} * Emissions per Gallon of Fuel (tons/gallon)

For Power Flow Control, Automated Voltage and VAR Control, Customer Electricity Use Optimization Storing Electricity for Later Use, and Distributed Production of Electricity the reduction is due to reducing the amount of central generation needed to meet demand. More specifically, the reduction in emissions is associated with reducing peak demand and reducing the use of central generation. Therefore, the emissions associated with central generation would have to be determined for each project based on the generation mix in the service territory of the project. The emissions (or emissions avoided) would then be reported directly.

Emissions (tons) = Calculated and reported by the project directly.

If PEVs that are being used as service vehicles, or being deployed throughout the service territory as part of studies, there will be an avoided emissions benefit associated with the electricity that these vehicles use instead of burning fuel. The avoided emissions are calculated using the following formula:

Emissions Avoided (tons) = kWh of Electricity Consumed by PEVs (kWh) * Electricity to Fuel Conversion Factor (gallons/kWh) * Emissions per Gallon of Fuel (tons/gallon)

All of these sources of emissions and avoided emissions would be aggregated for a particular project and monetized according to the following formulae:

**Value ($)** = Σ{Net Emissions Avoided (tons)* Value of Emissions ($/ton)}

Net Emissions Avoided (tons) = $[\text{Emissions (tons)}]_{\text{Baseline}}$ - $[\text{Emissions (tons)}]_{\text{Project}}$

Net Emissions Avoided (tons) = $[\text{Emissions Avoided(tons)}]_{\text{Project}}$ - $[\text{Emissions Avoided (tons)}]_{\text{Baseline}}$

C.21 Reduced Oil Usage

The Reduced Oil Usage benefit can be realized through four functions:

- Automated Feeder and Line Switching
- Diagnosis & Notification of Equipment Condition
- Real Time Load Measurement and Management
- Storing Electricity for Later Use

To determine the impact of this benefit, an estimate of the fuel consumed per truck roll is used. For Automated Feeder and Line Switching, the project will report the typical number of switching operations performed per feeder or region as a baseline and estimate the fuel consumed per switching operation. For Diagnosis & Notification of Equipment Condition, the project will report the typical number of trips to perform maintenance per feeder or region as a baseline and estimate the fuel consumed per maintenance operation. For Real Time Load Measurement and Management, the project will report the number of trips to perform meter reading and other meter operations as a baseline and estimate the fuel consumed per maintenance operation. The project will track the number operations that are performed during the project, and estimate the fuel savings by not rolling a truck to perform them manually.

For Automated Feeder and Line Switching, Diagnosis & Notification of Equipment Condition, and Real Time Load Measurement and Management, in order to estimate the fuel use the project can count the overall number of truck rolls for all of these events and use the equation below:

Fuel Use (gallons) = Truck Rolls (# of events) * Average Miles Travelled per Truck Roll (miles/event) ÷ Average Fuel Efficiency for Truck Roll Vehicle (miles/gallon)

Alternatively the project can count the number of operations performed for each of these categories separately and use the formula below to estimate fuel use:

Fuel Use (gallons) = Σ{Number of Operations Completed(# of events) * Average Miles Traveled per Operation (miles/event) ÷ Average Fuel Efficiency for Service Vehicle (miles/gallon)}

If PEVs are being deployed the electrical energy used by PEVs displaces the equivalent amount of gasoline. However, the PEVs may not be individually metered; therefore, the project may be required to estimate how much electricity is used to charge them.

Avoided Fuel Use (gallons) = kWh of Electricity Consumed by PEVs (kWh) * Electricity to Fuel Conversion Factor (gallons/kWh)

All of these sources of fuel use and avoided fuel use would be aggregated for a particular project and monetized according to the following formulae:

Value (gallons of oil) = Net Avoided Fuel Use (gallons)* Fuel to Oil Conversion Factor (gallons oil/gallon fuel)

> **Net Avoided Fuel Use (gallons)** = $[\text{Fuel Use (gallons)}]_{\text{Baseline}}$ - $[\text{Fuel Use (gallons)}]_{\text{Project}}$
>
> **Net Avoided Fuel Use (gallons) =** $[\text{Avoided Fuel Use (gallons)}]_{\text{Project}}$ - $[\text{Avoided Fuel Use (gallons)}]_{\text{Baseline}}$

C.22 Reduced Wide-scale Blackouts

The Reduced Wide-scale Blackouts benefit can be realized through two functions:

- Wide Area Monitoring and Visualization
- Dynamic Capability Rating

The value of this benefit could be estimated by calculating the number of blackouts that would be avoided and the cost of each event. The project would report instances where conditions were detected that could have put the system at great risk in the past. These could be considered a Wide-scale Blackout "event," and then the expected cost of the event would be estimated by the project. Alternatively, this benefit could be estimated by tracking the number of blackout events that take place and the cost of those events. For the baseline the project would estimate the impact and cost of those events assuming no smart grid technology had been installed. The monetary impact of this benefit is calculated using the following formula:

Value ($) = [Number of Wide-scale Blackouts (# of events) * Estimated Cost of each Wide-scale Blackout ($/event)]$_{\text{Baseline}}$ - [Number of Wide-scale Blackouts (# of events) * Estimated Cost each Wide-scale Blackout ($/event)]$_{\text{Project}}$

C.23 Cost Calculations

The cost calculations of the SGCT involve three basic steps:

1. Determine a nominal cost schedule
2. Determine a present value cost schedule
3. Determine the NPV of the project

Determining a nominal cost schedule can be accomplished in two ways: 1) the user can directly enter a nominal cost schedule 2) the SGCT can calculate a cost schedule based on user inputs.

The cost entered into the SGCT should represent the total installed cost of the project and should include all capital costs and direct labor costs, i.e. construction, installation, integration, testing, and commissioning.

Manual cost schedule entries may begin two years prior from the project start date and extend until 2040.

In order for the SGCT to determine a cost schedule, you must enter the inputs listed in Table C-3 into the SGCT.

Table C-3. Cost Calculation Inputs

Input	*Description*
Initial Year of Project Spending	The first year in which payments for project capital costs are made.
Final Year of Project Spending	The last year that payments for project capital costs are made
Total Capital Cost of the Project	The total capital cost of the project including direct labor costs, i.e. construction, installation, integration, testing, and commissioning.
Interest Rate	The interest rate that would be paid on financing the total capital cost of the project.

From these inputs, the nominal cost schedule is calculated by amortizing total capital cost evenly over the spending period according to the following equation:

$$A = P \cdot \frac{r(1+r)^t}{(1+r)^t - 1}$$

Where:

A = Yearly Amortize Cost
P = Total Capital Cost of the Project
r = Interest Rate
t = Total time (years) over which cost is amortized

To determine the present value cost schedule, each year of the nominal cost schedule (user-entered or SGCT-calculated) is multiplied by the appropriate discount factor. For the project starting year the discount factor is 1. Each yearly cost is multiplied by the following discount factor:

$d_t = (1 - r_d)^t$

Where:

d_t = Discount factor in year t

r_d = Discount rate

t = Discount year, year 0 correspond to the project starting year. Negative year values are used for expenditures that occur before the project starting year.

In order to determine the NPV of the project, the present value cost schedule is subtracted from the present value total benefits schedule. The present value total benefits schedule is calculated by multiplying the total benefits schedule by the discount factor. Subtracting these two schedules yields the present value net benefit schedule. Summing this schedule yields the total project NPV.

Appendix D: Input Concepts: Detailed Explanations

This appendix presents detailed explanations of four key concepts embodied in the SGCT:

» Baseline
» Inputs for the SGCT
» Input Escalation Techniques
» Benefits Decline S-Curve Model (DOE version only)

Understanding these concepts is critical to the effective use of the tool.

D.1 The Baseline Concept

Baselines are required because simply measuring a metric in isolation does not allow one to determine the improvement that smart grid technology has made to the grid. For example, simply measuring SAIFI or SAIDI after installing advanced smart switches without having values to compare to will not allow someone to make an assessment about how this technology has improved reliability. To make this type of assessment, the measured value must be compared against some standard in order to make a statement about the improvement or benefit of the technology. For the SGCT, the standard against which metrics are measured is the ***baseline value***.

Determining the value of smart grid projects requires an understanding of how the system would have performed given a baseline build-out of smart grid technology. For most users, the most appropriate baseline build-out to use will be their electricity grid without smart grid technology. Defining baseline in this way will enable the user to use the SGCT to calculate the absolute benefit of the smart grid technology they are installing.

The DOE will use the SGCT to evaluate the benefits from the Smart Grid Investment Grant (SGIG) program and the Smart Grid Demonstration (SGD) program projects that were established as part of the American Recovery and Reinvestment Act (ARRA) legislation. In this analysis, the DOE wishes to understand the value of the SGD and SGIG programs in advancing the nation's smart grid. Therefore, in this analysis the baseline build-out will be defined as the electricity grid that would have existed had an award not been received; this baseline build-out may or may not include smart grid technology deployment. Once the baseline build-out is understood, baseline forecasts for the relevant SGCT inputs must be estimated by assessing how the grid would have performed given the baseline build-out. Depending on the metric and the nature of the project, baseline estimates may be derived from recent historical data, forecasts, statistical or model-based projections, or possibly by collecting data from comparison/control groups (e.g., similar feeders or households) during the course of the project.

D.2 Inputs for the SGCT

Each user of the SGCT must input data about the customer electricity rates and customer population (See section

4.2.2 Data Input Module (DIM)). These data are required because they are used in multiple benefit calculations. The SGCT allows the user to enter data for up to five customer sub-classes within each major customer class. Each subclass can be used to segment the major customer class and enter data specific to that sub-class. For example, the user may wish to define a sub-class for the residential customer major class that consists of customers with AMI infrastructure, dynamic pricing, and direct load control devices, and enter data for this class separately. If the user does not wish to define sub-classes, the data entered for sub-class 1 will represent the entire major customer class. If a user defines multiple sub-classes, then the data entered for electricity rates, customer population, and hourly customer electricity usage inputs should be segmented using the same sub-classes.

Customer electricity rates should capture the average or typical energy rate and demand charge for each customer sub-class. If a sub-class contains customers with different tariff schedules, or customers with variable pricing, then the rates should be averaged appropriately so a single value can be entered into the SGCT.

Table D-1 briefly summarizes all of the inputs required to calculate every benefit in the SGCT. This table contains inputs for both standard and optional calculations. These inputs are grouped according to the benefits that they are used to quantify.

Table D-1. Input Summary Table

Metric	*Units*	*Definition*
Annual Generation Cost	$	Total cost of producing or procuring electricity to serve load. This electricity could be produced by utility owned generation resources or purchased from a third party.
Avoided Annual Generator Dispatch	MWh	The annual amount of generation dispatch avoided as a result of: 1) more efficient operations (i.e. if generators can follow load more closely), and/or 2) the coordinated operation of energy storage or plug-in electric vehicle which results in avoided central generation dispatch.
Average Hourly Generation Cost	$/MWh	Average hourly cost to generate 1 MWh of energy. This could also be the average hourly cost to purchase 1 MWh of electricity from a supplier. This number is multiplied by the Avoided Annual Generator Dispatch to monetize the value of this benefit.
Annual Energy Storage Efficiency	%	The typical annual charge/discharge efficiency of all active utility energy storage devices. Mathematically this is represented as the average useful energy output from energy storage devices divided by the total electrical energy input.
Annual PEV Efficiency	%	The typical annual charge/discharge efficiency of PEV batteries which can be utilized as energy storage assets of the grid. This storage efficiency could improve over the next five years as a result of improving technology.
Energy Storage Use at Annual Peak Time	MW	The amount of energy storage power available to meet annual peak demand. By providing peak power from energy storage devices the amount of peak generation capacity can be reduced.
Distributed Generation Use at Annual Peak Time	MW	The amount of distributed generation capacity available to meet annual peak demand. By providing peak power from DG resources the amount of peak generation capacity can be reduced.

Metric	Units	Definition
PEV Use at Annual Peak Time	MW	The amount of power available from PEVs to meet annual peak demand. By providing peak power from PEVs the amount of peak generation capacity can be reduced.
Total Customer Peak Demand	MW	The total customer peak demand for customers within the project scope. For some projects, the scope might only include a subset of residential customers (i.e. residential customers with AMI technology). For other projects, the project scope might include all customers within the service territory (including commercial and industrial customers). This input should already include any impacts from energy efficiency, demand response, or any other programs and technology that result in customer electricity use optimization.
Price of Capacity at Annual Peak	$/MW	The price paid for peak capacity ($/MW), which represents the capital expenditures for conventional generation.
Capital Carrying Charge of New Generation	$	The total capital cost of a deferred generation plant or generation unit. This benefit assumes that deferral is primarily the result of reducing peak demand. Enter the total deferred cost in the first year that it will be deferred.
Generation Investment Time Deferred	yrs	The time in years that the generation investment will be deferred. Decimal numbers can be entered (ex. 5.5).
Ancillary Services Cost	$	Total annual cost of ancillary services, including spinning reserve and frequency regulation., Ancillary services could be reduced if: generators could more closely follow load; peak load on the system was reduced; power factor, voltage, and VAR control were improved; or information available to grid operators were improved.
Average Price of Reserves	$/MW	Typical market price for spinning and non-spinning reserves (ancillary services).
Reserve Purchases	MW	Amount of spinning and non-spinning reserves (ancillary services) purchased annually.
Average Price of Frequency Regulation	$/MW	Typical market price for frequency regulation service (ancillary service).
Frequency Regulation Purchases	MW	Amount of frequency regulation service (ancillary service) purchased annually.
Average Price of Voltage Control	$/MVAR	Typical market price for voltage support (ancillary service).
Voltage Control Purchases	MVAR	Amount of voltage support (ancillary service) purchased annually.
Congestion Cost	$	Total annual transmission congestion cost. Project functions that could reduce these costs either provide lower cost energy, decrease loading on system elements, shift load to off-peak, or allow the grid operator to manage the flow of electricity around constrained interfaces (i.e. dynamic line capability or power flow control).

Metric	*Units*	*Definition*
Congestion	MW	Annual congestion relief as a result of decrease loading on system elements, a shift of load to off-peak, or allowing the grid operator to manage the flow of electricity around constrained interfaces (i.e. dynamic line capability or power flow control).
Average Price of Congestion	$/MW	Average cost of congestion in the project territory or during the hours that the project provided congestion relief.
Capital Carrying Charge of Transmission Upgrade	$	The total capital cost of transmission system investments that can be deferred as a direct result of the project. Reducing the load and stress on transmission elements increases asset utilization and reduces the potential need for upgrades. Enter the total deferred cost in the first year that it will be deferred.
Transmission Investment Time Deferred	yrs	The time in years that the transmission investment will be deferred. Decimal numbers can be entered (ex. 5.5).
Capital Carrying Charge of Distribution Upgrade	$	The total capital cost of distribution system investments that can be deferred as a direct result of the project. Reducing the load and stress on distribution elements increases asset utilization and reduces the potential need for upgrades. Enter the total deferred cost in the first year that it will be deferred.
Distribution Investment Time Deferred	yrs	The time in years that the distribution investment will be deferred. Decimal numbers can be entered (ex. 5.5).
Capital Replacement of Failed Equipment	$	Capital expenditures related to replacing failed equipment within the project scope. Equipment that falls within the project scope can include equipment that may be impacted by enhanced monitoring and detection, reduction of fault currents, enhanced fault protection, or loading limits based on real-time equipment or environmental factors.
Portion Caused by Fault Current or Overloaded Equipment	%	An estimate or calculation of the percentage of equipment failures caused primarily by exposure to fault currents or overloads.
Portion Caused by Lack of Condition Diagnosis	%	An estimate or calculation of the percentage of equipment failures caused primarily by a lack condition diagnosis.
Total Transmission Equipment Maintenance Cost	$	The total annual cost of transmission equipment maintenance. Online diagnosis and reporting of equipment condition could reduce or eliminate the need to send people out to check or maintain equipment resulting in a cost savings.
Total Distribution Equipment Maintenance Cost	$	The total annual cost of distribution equipment maintenance. Online diagnosis and reporting of equipment condition could reduce or eliminate the need to send people out to check or maintain equipment resulting in a cost savings.

Metric	Units	Definition
Distribution Operations Cost	$	Total activity based cost for distribution operations during the reporting period. Cost related to feeder and capacitor switching operations as well as other distribution operations costs that could be impacted as a result of the smart grid project (ex. other field services or load research costs) could be input. Alternatively, the avoided distribution operations costs could be entered. Avoided costs should be entered as negative numbers.
Transmission Operations Cost	$	Total activity based cost for transmission operations during the reporting period. Cost related to line and capacitor switching operations as well as other transmission operations costs that could be impacted as a result of the smart grid project could be input. Alternatively, the avoided transmission operations costs could be entered. Avoided costs should be entered as negative numbers.
Distribution Feeder Switching Operations	$	Distribution operations cost related to feeder switching. Alternatively, the avoided costs of feeder switching associated with automated switches could be entered. Avoided costs should be entered as negative numbers.
Distribution Capacitor Switching Operations	$	Distribution operations cost related to capacitor switching. Alternatively, the avoided costs of capacitor switching associated with automated switches could be entered. Avoided costs should be entered as negative numbers.
Other Distribution Operations Cost	$	Other distribution operations costs that could be impacted as a result of the smart grid project (ex. other field services or load research costs). Alternatively, the avoided distribution operations costs could be entered. Avoided costs should be entered as negative numbers.
Meter Operations Cost	$	Total cost associated with meter reading operations. This cost can be measured or calculated by measuring number of meters to be read manually and estimating the average cost to manually read a meter. There may be other meter costs that could be included in this input such as costs to connect/disconnect customers, investigate customer outages, and conduct maintenance.
Number of Meter Tamper Detections - Residential	#	Total annual number of residential meter tamper cases detected and substantiated as legitimate theft attempts.
Number of Meter Tamper Detections - Commercial	#	Total annual number of commercial meter tamper cases detected and substantiated as legitimate theft attempts.
Number of Meter Tamper Detections - Industrial	#	Total annual number of industrial meter tamper cases detected and substantiated as legitimate theft attempts.

Metric	Units	Definition
Average Annual Customer Electricity Usage	kWh	These inputs represent the average annual electricity usage of a single typical residential, commercial, or industrial customer within the project scope. Because this input will be used to calculate the benefit of reduced electricity theft, the project scope should be defined by those customers who have AMI technology that can be used to detect electricity theft.
Distribution Feeder Load	MVA	Average apparent power readings for all feeders impacted by the project. This input will be used to calculate electricity losses so feeders that have been made more efficient or feeders that have had peak or average loadings decreased should be included. If substations have been made more efficient the average power level of the substation(s) should be input. Information should be based on hourly loads.
Distribution Losses	%	Average losses for the portion of the distribution system impacted by the project expressed as a percentage of total loading. This can be modeled or calculated.
Transmission Line Load	MVA	Average apparent power readings for all lines impacted by the project. This information will be used to calculate electricity losses so lines over which losses could be reduced as a result of the project should be included. Information should be based on hourly loads.
Transmission Losses	%	Average losses for the portion of the transmission system impacted by the project expresses as a percentage of total loading. This can be modeled or calculated.
Average Price of Wholesale Energy	$/kWh	Average wholesale market price of electricity. This input will be used to monetize electricity losses.
Total Residential Electricity Cost	$	Total amount of money spent on electricity by residential customers annually. This amount could be reduced as a result of new pricing programs, efficiency programs, demand response programs, and/or changes in usage habits.
Total Commercial Electricity Cost	$	Total amount of money spent on electricity by commercial customers annually.
Total Industrial Electricity Cost	$	Total amount money spent on electricity by industrial customers annually.
SAIDI (system)	Index	The System Average Interruption Duration Index for the entire system should be entered for this input. If the SAIDI just for the part of the system that will be impacted by the project is available use the optional inputs for the reliability calculation. SAIDI is defined as: Total Customer Hours Interrupted/Total Customers Served.
CAIDI (system)	Index	The Customer Average Interruption Duration Index for the entire system should be entered for this input. If the CAIDI just for the part of the system that will be impacted by the project is available use the optional inputs for the reliability calculation. CAIDI is defined as: Total Customer Hours Interrupted/Total Customers Interrupted.

Metric	Units	Definition
SAIDI (Impacted Feeders or Lines)	Index	System Average Interruption Duration Index is defined as: Total Customer Hours Interrupted/Total Customers Served. The customer data used to derive this index should only include customers on feeders that are expected to experience improved reliability as a result of installed DA equipment.
CAIDI (Impacted Feeders or Lines)	Index	Customer Average Interruption Duration Index is defined as: Total Customer Hours Interrupted/Total Customers Interrupted. The customer data used to derive this index should only include customers on feeders that are expected to experience improved reliability as a result of installed equipment.
Total Residential Customers Served by Impacted Feeders or Lines	#	Total number of specified customers served on feeders that will be impacted by project initiatives aimed at reliability.
Total Commercial Customers Served by Impacted Feeders or Lines		
Total Industrial Customers Served by Impacted Feeders or Lines		
Outage Time of Major Outage - Residential	hr	Total outage time experienced by residential customers from an interruption of electric service that is categorized as a major event by IEEE Std 1366-2003.
Number of Customers Affected by Major Outage - Residential	kW estimated	Number of total residential customers that experienced service interruption from an event defined as a major event by IEEE Std 1366-2003.
Outage Time of Major Outage - Commercial	hr	Total outage time experienced by commercial customers from an interruption of electric service that is categorized as a major event by IEEE Std 1366-2003.
Number of Customers Affected by Major Outage - Commercial	kW estimated	Number of total commercial customers that experienced service interruption from an event defined as a major event by IEEE Std 1366-2003.
Outage Time of Major Outage - Industrial	hr	Total outage time experienced by industrial customers from an interruption of electric service that is categorized as a major event by IEEE Std 1366-2003.
Number of Customers Affected by Major Outage - Industrial	kW estimated	Number of total industrial customers that experienced service interruption from an event defined as a major event by IEEE Std 1366-2003.

Metric	Units	Definition
Value of Service - Residential	$/kWh	Represents the true value of the electricity service to the specified customer without regard to the actual cost of providing the service. This input captures the value of service reliability quantified by the willingness of customers to pay for service reliability, taking into account the resources (e.g., income) of the residential customer or by a firm's expected net revenues associated with the added reliability.
Value of Service - Commercial		
Value of Service - Industrial		
Average Hourly Load Not Served During Outage per Customer	kW	These inputs represent the average hourly load (kW) of a typical residential, commercial, or industrial customer within the project scope. This average hourly load will be used to calculate the unserved electricity during an outage event. The project scope should be defined by those customers who are included in the SAIDI calculations.
Average Hourly Load Not Served During Outage per Customer		
Average Hourly Load Not Served During Outage per Customer		
Distribution Restoration Cost	$	Total annual distribution restoration costs. These costs can include line crew labor/material/equipment, support services such as logistics, call centers, media relations, and other professional staff time and material associated with service restoration.
Transmission Restoration Cost	$	Total annual transmission restoration costs. These costs can include line crew labor/material/equipment, support services such as logistics, call centers, and other professional staff time and material associated with service restoration.
Number of Outage Events	# of events	Annual number of outage events.
Restoration Cost per Event	$/event	Average restoration cost per outage event.
MAIFI (System)	Index	The Momentary Average Interruption Frequency Index for the entire system should be entered for this input. If the MAIFI for the part of the system that will be impacted by the project is available, use the optional inputs for this reliability calculation. MAIFI is defined as: Total number of Customer Momentary Outages (as defined by the IEEE)/Total Number of Customers Served.
Value of Service - PQ	$/# of customer inter-ruptions	Represents the true value of the avoided momentary outages to the utility customer without regard to the actual cost of providing the service. This input captures the value of service reliability quantified by the willingness of customers to pay for service reliability, taking into account the resources (e.g., income) of the residential customer or by a firm's expected net revenues associated with the added reliability.

Metric	*Units*	*Definition*
MAIFI (Impacted Feeders)	Index	MAIFI is defined as: Total number of Customer Momentary Outages (as defined by the IEEE)/Total Number of Customers Served. The customer data used to derive this index should only include customers on feeders that are expected to experience reduced momentary interruptions as a result of installed equipment.
Total Residential Customers Served on Impacted Feeders (momentary)	#	Total customers of the indicated type served on feeders that are expected to experience reduced momentary interruptions as a result of installed equipment.
Total Commercial Customers Served on Impacted Feeders (momentary)		
Total Industrial Customers Served on Impacted Feeders (momentary)		
Number of High Impedance Faults Cleared	# of events	The number of high impedance faults that were cleared without causing voltage sags.
Value of Service - Sags & Swells	$/event	The true value of the avoided power quality events (voltage) to the utility customer without regard to the actual cost of providing the service. This input captures the value of service reliability quantified by the willingness of customers to pay for service reliability, taking into account the resources (e.g., income) of the residential customer or by a firm's expected net revenues associated with the added reliability.
Truck Rolls	# of events	The number of truck rolls avoided as a result of distribution automation and AMI technology. Truck rolls can be avoided due to functionality such as remote meter reads, remote meter connect/disconnect, remote switching operations, automated diagnostics and notification, and remote outage verification.
Average Miles Travelled per Truck Roll	miles/ event	The average miles travelled per service call, maintenance operation, switching operation or other truck roll. The vehicles that would be used in the avoided truck rolls should be used to determine this input.
Average Fuel Efficiency for Truck Roll Vehicle	miles/ gallon	The average vehicle or fleet fuel efficiency (in miles per gallon) of the vehicles used for service calls and truck rolls. The vehicles that would be used in the avoided truck rolls should be used to determine this input.

Metric	*Units*	*Definition*
Number of Feeder Switching or Maintenance Operations Completed	# of events	Total number of manual feeder switching or maintenance operations performed per year. Alternatively, the avoided number of manual switching operations could be entered. If avoided switching operations are entered they should be entered as negative numbers.
Average Miles Traveled per Switching or Maintenance Operation	miles/ event	Average miles traveled per feeder switching or maintenance operation.
Average Fuel Efficiency for Feeder Service Vehicle	miles/ gallon	Average vehicle or fleet fuel efficiency for feeder service vehicles.
Number of Diagnosis /Notification Operations Completed	# of events	Total number of manual inspections performed per year. Alternatively, the avoided number of manual diagnosis/notification operations could be entered. If avoided inspections are entered they should be entered as negative numbers.
Average Miles Traveled per Diagnosis /Notification Operation	miles/ event	Average miles traveled per inspection.
Average Fuel Efficiency for Diagnosis /Notification Service Vehicle	miles/ gallon	Average vehicle or fleet fuel efficiency for service vehicles used for equipment diagnosis operations.
Number of Meter Reading Operations	# of events	Total number of manual meter reads performed per year. Alternatively, the avoided meter reads could be entered. If avoided meter reads are entered they should be entered as negative numbers.
Average Miles Traveled per meter read	miles/ event	Average miles traveled per meter read.
Average Fuel Efficiency for Real-Time Load Measurement/Management Service Vehicle	miles/ gallon	Average vehicle or fleet fuel efficiency for service vehicles used for meter reading.
kWh of Electricity Consumed by PEVs	kWh	The total electricity consumed by PEVs in the service territory. This could be determined from data collected from PEV charging stations.

Metric	Units	Definition
Electricity to Fuel Conversion Factor	gallons/ kWh	The equivalent amount of gasoline a PEV would use by consuming one kWh of electricity.
CO2 Emissions per Gallon of Fuel	tons/ gallon	The typical amount of CO2 emitted from burning a gallon of fuel in vehicles used for service calls and truck rolls. The default data is based on gasoline fuel.
CO2 Emissions	tons	CO2 emissions from central generating sources. Functionalities such as Automated Voltage and VAR Control, Customer Electricity Use Optimization, Plug-in Electric Vehicles, Stationary Electric Storage, Distributed Generation, and Power Flow Control can offset central generation, reduce line losses, and increase renewable integration, which can lead to fewer CO2 emissions. Alternatively, the avoided CO2 emissions could be entered. Avoided emissions should be entered as negative numbers.
Value of CO2	$/ton	The anticipated or current market price of carbon emissions.
Sox Emissions per Gallon of Gas	tons/ gallon	The typical amount of SOx emitted from burning a gallon of fuel in vehicles used for service calls and truck rolls. The default data is based on gasoline fuel.
NOx Emissions per Gallon of Gas	tons/ gallon	The typical amount of NOx emitted from burning a gallon of fuel in vehicles used for service calls and truck rolls. The default data is based on gasoline fuel.
PM-2.5 per Gallon of Gas	tons/ gallon	The typical amount of PM-2.5 emitted from burning a gallon of fuel in vehicles used for service calls and truck rolls. The default data is based on gasoline fuel.
SOx Emissions	tons	The SOx, NOx, or PM-10 (or PM-2.5) emissions from central generating sources. Functionalities such as Automated Voltage and VAR Control, Customer Electricity Use Optimization, Plug-in Electric Vehicles, Stationary Electric Storage, Distributed Generation, and Power Flow Control can offset central generation, reduce line losses, and increase renewable integration, which can lead to fewer CO2 emissions. Alternatively, the avoided CO2 emissions could be entered. Avoided emissions should be entered as negative numbers.
NOx Emissions		
PM-2.5 Emissions		
Value of SOx	$/ton	The anticipated or current market price of SOx emissions.
Value of NOx	$/ton	The anticipated or current market price of NOx emissions.
Value of PM-2.5	$/ton	The anticipated or current market price of PM-10 (or PM-2.5) emissions.
Number of Wide-scale Blackouts	# of events	The number of wide-scale blackouts per year.
Estimated Cost of each Wide-scale Blackout	$/event	The average, typical or calculated cost of each blackout event.

D.3 Input Escalation Techniques

The SGCT requires that you enter five years of baseline data and at least one year of project data. With these inputs, the SGCT can calculate benefits beyond the first five years by escalating project and baseline values using various methods and factors described below.

After the fifth year, baseline and project inputs are escalated either by the default escalation factors presented in Tables D-2 through Table D-6 or by user-entered escalation factors, or are held constant. Different inputs are escalated by different factors. Table D-2 summarizes which escalation factors are used to escalate the various inputs. If an input is escalated by multiple escalation factors, the input is simply escalated by the sum of the two escalation factors. If an input is not represented in Table D-2, then it is held constant after the fifth year.[9]

[9] This is true for all inputs except for reliability indices. The average of the last three years of entered data is projected forward without escalation for all reliability indices inputs.

Table D-2. Summary of Inputs Projected by Escalation Factors

Escalation Factor	*Inputs that are projected by escalation factor*
Population	Number of Meter Tamper Detections – Residential, Commercial, Industrial Number of Meter Reading Operations kWh of Electricity Consumed by PEVs
Load Growth	Avoided Annual Generator Dispatch Energy Storage Use at Annual Peak Time Distributed Generation Use at Annual Peak Time PEV Use at Annual Peak Time Reserve Purchases Frequency Regulation Purchases Voltage Control Purchases Congestion Distribution Feeder Load Transmission Line Load
Inflation	Capital Replacement of Failed Equipment Total Transmission Equipment Maintenance Cost Total Distribution Equipment Maintenance Cost Distribution Operations Cost Transmission Operations Cost Distribution Feeder Switching Operations Distribution Capacitor Switching Operations Other Distribution Operations Cost Meter Operations Cost Value of Service – Residential, Commercial, Industrial Distribution Restoration Cost Transmission Restoration Cost Restoration Cost per Event Value of Service - PQ Value of Service - Sags & Swells Value of CO_2, SO_x, NO_x, PM-2.5 Estimated Cost of each Wide-scale Blackout
Energy Price	Average Hourly Generation Cost Price of Capacity at Annual Peak Average Price of Reserves Average Price of Frequency Regulation Average Price of Voltage Control Average Price of Congestion Average Price of Wholesale Energy
Energy Price & Load Growth	Annual Generation Cost Ancillary Services Cost Congestion Cost
Energy Price & Population Growth	Total Electricity Cost – Residential, Commercial, Industrial

Table D-3. Default Population Growth Escalation Factors by Region

NERC Region	*Default Escalation Factor Value*[10]
1. NPCC	0.2%
2. RFC	0.3%
3. MRO	0.4%
4. FRCC	2.0%
5. SERC	0.9%
6. SPP	0.4%
7. TRE	1.6%
8. WECC	1.3%
9. ASCC	1.1%
10. HI	0.6%

Table D-4. Default Load Growth Escalation Factors by Region

NERC Region	*Default Escalation Factor Value*[11]
1. NPCC	0.8%
2. RFC	1.4%
3. MRO	2.3%
4. FRCC	2.6%
5. SERC	2.2%
6. SPP	1.8%
7. TRE	2.2%
8. WECC	1.6%
9. ASCC	2.2%
10. HI	1.3%

[10] Source: U.S. Census Bureau, Population Division, Interim State Population Projections, 2005. http://www.census.gov/population/www/projections/projectionsagesex.html

[11] Source: 1990 - 2008 Retail Sales of Electricity by State by Sector by Provider (EIA-861), http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

Table D-5. Default Inflation Escalation Factors by Region

NERC Region	*Default Escalation Factor Value*[12]
1. NPCC	2.7%
2. RFC	2.1%
3. MRO	2.1%
4. FRCC	2.9%
5. SERC	2.4%
6. SPP	2.1%
7. TRE	2.3%
8. WECC	2.4%
9. ASCC	2.6%
10. HI	2.8%

Table D-6. Default Energy Price Escalation Factors by Region

NERC Region	*Default Escalation Factor Value*[13]
1. NPCC	3.3%
2. RFC	2.5%
3. MRO	1.5%
4. FRCC	2.5%
5. SERC	1.8%
6. SPP	1.4%
7. TRE	3.9%
8. WECC	2.2%
9. ASCC	2.5%
10. HI	7.2%

The final escalation technique used in the SGCT allows the tool to complete its analysis even if less than five years of project data are entered. It accomplishes this by interpolating the missing project data with the trend in the baseline dataset. For example, if the baseline values for years 2011 and 2012 were 100 and 120 respectively, and the project value for year 2011 was 50, the SGCT would interpolate the missing 2012 project value to be 60 (20% higher).

Benefits can be calculated out to the year 2040. However, the user sets the parameter that determines when benefits decline to zero (see Section 4.2.2 Data Input Module (DIM), DIM Step II). After the first year in which benefits are zero, all benefits are automatically set to zero for the remaining years.

---

[12] Source: US Bureau of Labor and Statistics CPI Database, All Urban Consumers (Current Series) (Consumer Price Index - CPI), All Items, http://www.bls.gov/cpi/#tables

[13] Source: 1990 - 2008 Average Price by State by Provider (EIA-861), Industry Sector Category = Full-Service Providers, http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html

D.4 Benefits Decline S-Curve Model

The following methodology is implemented only in the DOE version of the SGCT, and is not implemented in the public version. The reason is that the DOE plans to use the SGCT to determine the benefit of its smart grid investment grant programs in accelerating and/or enhancing the smart grid buildout, rather than the benefit of an electrical system with or without a smart grid. Therefore, benefits are defined by the difference between the smart grid that resulted from the grant awards and the smart grid that would have happened without them.

Because the benefit definition focuses on two versions of a smart grid, the year in which all benefits for a particular project decline to zero isn't necessarily determined by the useful lifetime of the smart grid assets. Rather, it is defined by the year in which the baseline smart grid build-out would have reached parity with the actual smart grid build-out. Therefore, the benefit decline is assumed to be gradual, shaped by the differences in timing and speed of the build-outs of the baseline and actual scenarios.

This gradual decline in benefits is modeled in the DOE version of the SGCT using an S-curve. The S-curve qualitatively captures the rapid decline in benefits one would expect as baseline build-out is rapidly completed, followed by the gradual decline that would have occurred as operation of the baseline system is optimized and refined. The details of this S-curve model for benefits decline are explained below.

In the DOE version of the SGCT, all benefits are calculated by determining the difference between the actual status of the electricity system and the counterfactual baseline status. The electricity system in the baseline scenario for the DOE analysis is the hypothetical system that would have existed had the utility not received a government grant to complete the smart grid project. It is assumed that the baseline smart grid would eventually reach parity with the project system, because the utility would have implemented smart grid technology that is on par with the project scenario at some point in the future. Therefore, because benefits are derived from the difference between the baseline and project scenarios benefits are expected to decline to zero over time. Benefits decline gradually rather than stopping abruptly because even when the full suite of smart grid technology has been installed in the baseline scenario there is assumed to be a time period over which utility workers must learn to optimize the operation of the equipment.

In order to model this decline, the SGCT leverages the following logistic function:

$$P(t) = \frac{1}{1 + e^{b\cdot(t-Y)}}$$

where:

$P(t) = \textit{Portion of calculated benefit derived in year } t$

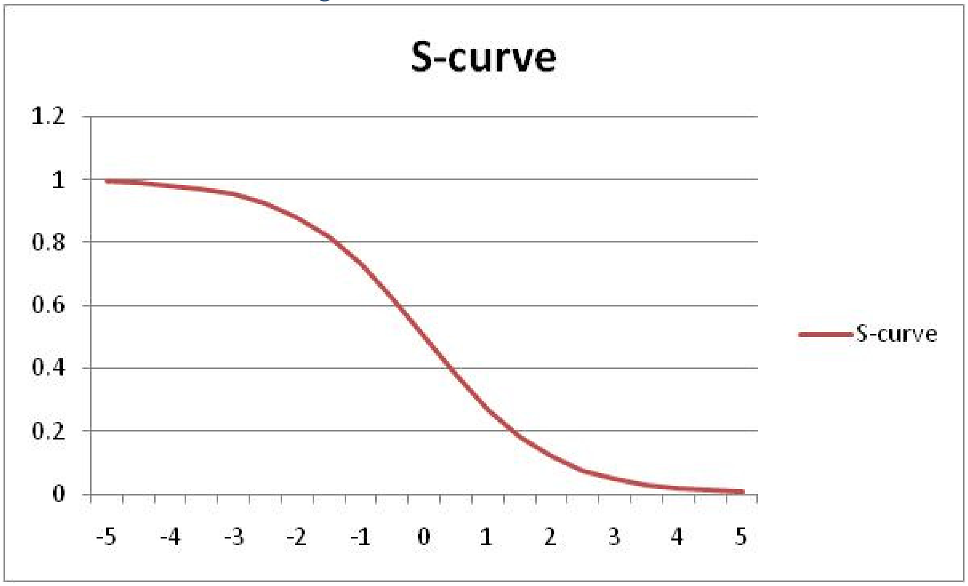
$t = \textit{year}$

$Y = \textit{year that the baseline system would have reached parity with the project system}$

b = parameter that controls the steepness of the s-curve decline.

The logistic function, $P(t)$, yields an s-shaped curve that has a limit of 1 and 0 as t approaches -∞ and +∞ respectively. The shape of the logistic function is depicted in Figure D-1.

Figure D-1. Illustrative S-curve



A key parameter the user must enter is the parity year, *Y* (see *DIM Step II* in Section 4.2.2 Data Input Module (DIM) for further details). Thus, the user has full control over when benefits begin to decline. If the user does not want benefits to decline at all between the project start year and 2040, the parity year can be set to something much larger than 2040.

After all forecasted benefits are calculated using the forecasted inputs, each benefit value is multiplied by the logistic function. As a result, in years that are much before the parity year *Y*, essentially all benefit is derived. As the year approaches the parity year, benefits begin to decline. This corresponds to receiving some benefit from the baseline scenario as the baseline system is being built. When *t* equals *Y* the logistic function *P(t)* equals 0.5. In other words, in the year that the baseline system would have reached parity with the project system, the amount of benefit derived is estimated to be about half of the calculated amount. The reason derived benefits are not equal to zero in year *Y* is because a project team would likely require a couple of years of operating the system after completing build-out in order to yield maximum benefit. Depending on the value of the *b* parameters, all benefits automatically decline to zero in one to seven years after year *Y*.

The SGCT also allows the user to set the number of years after the parity year that benefits will decline to zero. Users can choose to have benefits to decline to zero in one to seven years after the parity year. Depending on which option the user chooses the tool assigns a value to the *b* parameter which will cause the s-curve to be more or less steep and in turn cause benefits to decline to zero over different periods of time. Table D-7 shows how user inputs are translated to *b* parameters in the tool.

Table D-7. Correspondence between *b* parameter and user input

b parameter	User input
0.50	7 years from the parity date benefits degrade to zero.
0.58	6 years from the parity date benefits degrade to zero.
0.70	5 years from the parity date benefits degrade to zero.
0.87	4 years from the parity date benefits degrade to zero.
1.16	3 years from the parity date benefits degrade to zero.
1.74	2 years from the parity date benefits degrade to zero.
3.48	1 year from the parity date benefits degrade to zero.

In summary, fitting escalated benefits to the s-curve allows the SGCT to realistically model benefit decline in light of the fact that a smart grid system would have been implemented at some point in the baseline scenario.

Figure D-2 shows the escalation factor input page for the DOE version of the SGCT. The last two parameters the user enters on this page correspond to the Y and b parameter of the s-curve, respectively.

Figure D-2. Escalation Factor Input Page for the DOE Version of the SGCT

Step II: Enter Benefit Calculation Input Data, Escalation Factors

Directions: The Smart Grid Computational Tool can calculate costs and benefits of the smart grid project out to the year 2040. In order to complete this analysis escaltion factors are applied to the inputs that have been entered. On this page the user can choose to use default escalation factors or they can enter their own escalation factors in the "Value" column. To view a list of inputs affected by an escalation factor click the blue buttons in the "Inputs Affected" column. Additionally, the user can enter a date at which the benefits from the project will begin to decline. If no values are entered in the "Value" column the default values will be used. Once the user is finished click the button below the chart to return to the PDIM Main Page.

Escalation Factor	Description	Inputs Affected	Value	Default Value
Population Growth Factor	This escalation factor represents the customer population growth of the service area that the project impacts.	View List of Inputs		0.40%
Load Growth Factor	This escalation factor represents the electricity load growth of the service area that the project impacts.	View List of Inputs		2.30%
Economic Inflation Factor	This escalation factor represents the approximate economic inflation in the area that the project is located.	View List of Inputs	1.40%	2.10%
Energy Price Factor	This escalation factor represents the approximate inflation rate of costs related to energy (i.e. whole sale electricity price, cost of ancillary services, congestion costs)	View List of Inputs		1.50%
Year that baseline smart grid build out reaches project level	This parameter represents the year the the baseline smart grid build would have reached parity with the project smart grid build out. In other words it represents the year that the two systems would have been approximately equal. The baseline build out is the smart grid infrastructure that would have been implemented had a government grant not been awarded.	This parameter affects all benefit calculations. This year determines when the benefits (calculated by determining the delta between project and baseline inputs) of the project begin to approach zero.		2019
The baseline smart grid system would have reached parity with the project smart grid system by 2019. How many years after this date would you expect all benefits to decrease to zero? Keep in mind benefits are calculated as the difference between the project and baseline scenarios.		This parameter affects all benefit calculations.		3 years from the parity date benefits degrade to zero.

Return to PDIM Main Page

The Escalation Factor Input page is where the user enters the baseline build-out parity year Y. This is the year that the counterfactual baseline smart grid system would have reached build-out parity with the actual smart grid project being implemented. This date will help determine the time period over which the projected benefits will decline to zero. The user should also enter the number of years after the parity year that benefits will completely decline to zero. This is the other parameter that determines the time period over which projected benefits decline to zero.