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

ES COMPUTATIONAL TOOL (ESCT) VERSION 1.2 – USER GUIDE

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Preface

This document explains the background, methodology, assumptions, and step-by-step instructions necessary to utilize the ES Computational Tool (ESCT) in the most effective way. The introduction section provides a summary of the Department of Energy (DOE) Smart Grid Demonstration programs, an explanation of the history of the ESCT, and an explanation of the tool's purpose and uses. Later sections of this document provide a description of the DOE ES benefit analysis methodology, an overview of the ESCT architecture, and step-by-step instructions for using the ESCT. The appendices provide further detail about the methodology, calculations, and assumptions used in the ESCT.

Disclaimer

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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, is 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, including projects from the SGIG and SGD programs, to be evaluated consistently. In order to facilitate the use of the approach developed by the CBA team, Navigant Consulting Inc. (Navigant) incorporated it into an Excel™ tool called the Smart Grid Computational Tool (SGCT). The purpose of the SGCT is to guide a user through the cost-benefit analysis; it identifies the expected benefits of the deployment, collects all required inputs, runs the necessary calculations and presents the results in the form of tables and graphs.

Building off the broader framework developed for evaluating the costs and benefits of an entire smart grid project, Navigant developed a framework to evaluate the costs and benefits of ES (ES) deployments specifically. In addition to leveraging the broader smart grid framework, the framework outlined in the 2010 Sandia report titled "ES for the Electricity Grid: Benefits and Market Potential Assessment Guide" was a key source in the development of the ES analytical framework. This ES framework was then incorporated into an Excel™ tool similar to the SGCT called the Energy Storage Computational Tool (ESCT). Like the SGCT, the ESCT helps the user identify and quantify ES project benefits and costs. The primary purpose of the tool is to analyze operational deployments, but the tool can also be used to analyze proposed or hypothetical projects.

The ESCT can 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, contractors, and grant recipients can use the ESCT to calculate and track the costs and benefits of ES technologies deployed through the SGIG and SGD programs. Other stakeholders can use the ESCT to compare the benefits and costs of their own projects of interest and to gain a clearer understanding of the value of ES technology. The ESCT 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. Table 1 summarizes the main characteristics and advantages of the ESCT.

Table 1. ES Computational Tool characteristics and advantages

<table>
<tr><th colspan="2">Characteristics of the ESCT</th><th>Advantages</th></tr>
<tr><td>Primary Purpose</td><td>The tool guides the user through an analysis that quantifies the benefits and costs of an operational ES project.</td><td rowspan="5">• Straightforward to use
• Lends itself to quality control
• Provides a consistent and credible method for identification and calculation of benefits
• Ensures consistency of results
• Well suited for long term analysis</td></tr>
<tr><td>Secondary Purpose</td><td>The tool can help a user evaluate the potential benefits and costs of a proposed or hypothetical project.</td></tr>
<tr><td>Method of Use</td><td>The analysis is conducted in Excel™ and can be saved, edited, and updated.</td></tr>
<tr><td>Analytical Rigor</td><td>The tool leverages a combination of the Sandia and Navigant frameworks which consistently identify and calculate ES benefits.</td></tr>
<tr><td>Calculations</td><td>The tool uses standardized benefit calculations.</td></tr>
</table>

2.0 Analytical Framework

2.1 General Method for Determining ES Benefits

This subsection explains, at a high level, the general method for determining the benefits of an ES deployment. The subsections that follow this one will delve into the different parts of this method in detail.

The ESCT characterizes ES projects by identifying key characteristics of the ES deployment (i.e. by identifying the location, type of market, owner and type of ES asset deployed) and by identifying how that deployment will be used (i.e. the applications it will it be used for). Different applications will lead to various benefits whose monetary value can be quantified using sets of equations and appropriate inputs. 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 an ES deployment.

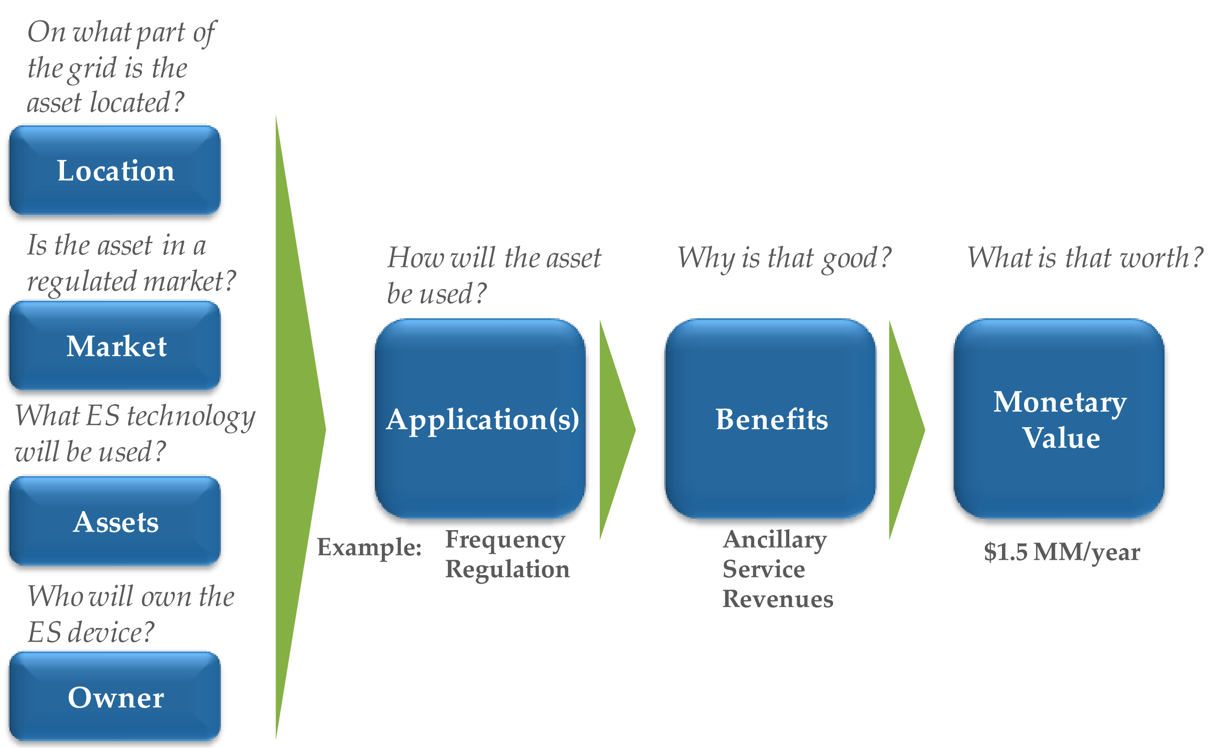

Figure 1. Methodology for determining the monetary value of an ES deployment

The first step in identifying a project's benefits and associated monetary value is to identify the assets that will be deployed, the owner of those assets, the type of market they will be deployed in, and the location of the deployment on the grid. Depending on these characteristics, a subset of applications is feasible. Applications describe how the ES device can be used to perform a service which results in some value or benefit. Each application is mapped to one or more benefits. Each benefit has one or more equations associated with it, which are used to monetize the benefit. The equation used to monetize any given benefit depends on the characteristics of the deployment (i.e. the location, market, and owner of the deployment). Finally, if project data is available, the monetary value of each realized benefit can be calculated. The monetary value of project benefits can be aggregated and used in a cost-benefit analysis. The value of the benefits can be attributed to non-utility merchants, ratepayers/utilities, customers, or society depending on the nature of the benefit.

2.2 Relationships of Location, Market, Owner and Assets to Applications

The first step in determining the benefits of an ES deployment is to identify the ES assets that a project will implement. In the ESCT the user can chose to evaluate the following assets:

- Pumped Hydro Storage (PHS)
- Compressed air energy storage (CAES)
- Flywheel
- Supercapacitor
- Battery, Sodium Sulfur
- Battery, Lead Acid
- Battery, Advanced Lead Acid
- Battery, Lithium Ion
- Flow Battery, Zn-Br
- Flow Battery, Fe-CR
- Flow Battery, Vanadium

Table 5 in Appendix A provides a more detailed description of each asset. Selecting any one of these assets determines the default technical and financial parameters that will be used in the tool. These parameters determine to some extent what applications are available for analysis in the tool. However, the user has freedom to change the technical and financial parameters used in the tool.

The location, market, and owner of the ES deployment must also be specified in order to determine which applications and benefits are available. The location describes where on the grid the deployment is physically located. The market describes whether the ES is deployed in a service territory that has gone through electricity market restructuring (deregulated) or not (regulated). The owner describes the entity or organization that owns and operates the storage device, to whom most or all of the benefit will accrue. Table 2 lists and describes the locations, markets, and owners that the user can evaluate in the ESCT.

Table 2. Definition of Location, Market, and Owner Criteria

Criteria	Criteria Sub-category	Definition
Location	Generation & Transmission (G&T)	This location describes any point between the generator and the power transformer at a step-down distribution substation.
	Distribution	Storage located on this part of the electricity delivery system is located between a distribution step-down substation and the end-user. Storage is also located on this part of the system if it is located in the step-down substation and is located on the secondary side of the transformer. Furthermore, storage deployed in a "community energy storage" configuration is considered to be on this part of the system. Finally, this could also include energy storage in the form of electric vehicles charging at stations owned by the utility.
	End-User	Storage located on this part of the electricity delivery system is located behind the end-users electric meter. This could include energy storage in the form of electric vehicles charging at residential, commercial or industrial locations.
Market	Regulated	A market in which utilities are vertically integrated, incorporating most elements of electric delivery and service into a single company.
	Deregulated	A market in which vertical integration at utilities has been broken up, allowing for independent power producers and merchant generators.
Owner	Utility	An asset owner that maintains and operates a local transmission and or distribution grid, such as an investor-owned utility, municipal utility, or electricity cooperative.
	Non-Utility Merchant/Independent Power Producer	An asset owner that can independently deploy generation and ES assets for wholesale market participation or contracts with utilities or end users.
	End-User	An asset owner that is primarily an end-user of electricity.

ES assets can be used to provide services which result in benefits. The possible services that are available for the user to analyze in the ESCT are described by the eighteen applications[1] listed below.

- Electric Energy Time-shift
- Electric Supply Capacity
- Load Following
- Area Regulation
- Electric Supply Reserve Capacity
- Voltage Support
- Transmission Support
- Transmission Congestion Relief
- Transmission & Distribution (T&D) Upgrade Deferral

[1] This list of applications is based on the applications described in Sandia Report SAND2010-0815, "Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide", February 2010.

- Substation On-site Power
- Time-of-use (TOU) Energy Cost Management
- Demand Charge Management
- Electric Service Reliability
- Electric Service Power Quality
- Renewables Energy Time-shift
- Renewables Capacity Firming
- Wind Generation Grid Integration - Short Duration
- Wind Generation Grid Integration - Long Duration

Table 6 in Appendix A provides a more detailed description of each application. Depending on the technical characteristics, the location, market and owner of the ES asset, one or more of these applications will be available for the user to evaluate using the ESCT. Table 7 in Appendix A summarizes some of the technical criteria that are used to determine which applications are feasible. The user selects a primary application and up to two secondary (or synergistic) applications. The primary application describes how the ES deployment will be used for the majority of the year. It is assumed that the primary application will yield the highest value to the owner in terms of benefits. Secondary applications describe the ways in which the ES unit will be used when not being used for the primary application. Benefits from primary and secondary applications are calculated independent of one another. That is, the tool does not assume that primary and secondary applications take place at the same time and therefore benefits from each application are calculated independently and aggregated in the results section of the model.

Although the user can select any technically feasible application as a secondary application, only a subset of applications will be suggested as viable synergistic applications. The applications that are included in this subset depend on compatibility between the primary application selected and technically feasible applications. General compatibility between applications is based on various considerations including: how frequently a battery must be charged and discharged, the power and energy requirements, the typical charge/discharge schedule required, where the storage must be located, and who the owner must be to pursue an application. Table 8 in Appendix A summarizes the secondary applications that are available given the primary application that has been selected.

2.3 Relationships of Applications to Benefits

Based on the applications that are being pursued by the ES deployment, a subset of benefits will be achievable. The benefits included in the ESCT are categorized as Economic, Reliability, or Environmental. As shown in Table 3 these benefit categories comprise 8 subcategories and 16 individual benefits. The descriptions of these benefits can be found in Table 8 in Appendix A. The relationship between ES applications and the expected benefits is illustrated in Table 4

The benefits denoted with a "P" in Table 4 are the primary benefits associated with the application. The ESCT quantifies these benefits and they will represent a bulk of the total value derived from that application. The benefits denoted with an "S" in Table 4 are the secondary benefits associated with the application. The ESCT quantifies these benefits and they will typically represent a significant portion of the total value derived from that application. The other benefits indicated by a green box in Table 4 represent the additional benefits associated with the application.

By default, the ESCT does not quantify additional benefits in the main part of the tool. Instead, these benefits are initially presented qualitatively. The user then has the option to work through various worksheets in the Computational Module in order to quantify these types of benefits. These benefits are not quantified by default for one or more of the following reasons:

1) The equations to calculate these benefits would require inputs that are very difficult to measure.
2) These benefits may accrue to stakeholders that are not the owners of the ES assets.
3) The monetary value associated with these benefits may be very small when only considering a single deployment as opposed to considering a system-wide deployment of ES.
4) The benefits only arise under specific circumstances.
5) The calculations utilize estimated inputs as opposed to measured data to monetize the benefits.

Any additional benefits an ES deployment may achieve are captured qualitatively in the ESCT. When reviewing the results of an analysis there will be a table which lists all of the additional benefits that might be achieved by the deployment along with an explanation of the rationale that could lead to that benefit. If after reading the explanation, the user wishes to calculate the value of the benefit, they can click a link which will open a worksheet that will collect the additional inputs required to monetize these benefits.

The detailed equations for calculating each benefit, as well as the rationale for the association of benefits with each application are described in Appendix C: Additional Benefit Calculations.

Table 3. List of ES Benefits

Benefit Category	Benefit Sub-category	Benefit
Economic	Market Revenue	Arbitrage Revenue Capacity Market Revenue Ancillary Services Revenue
	Improved Asset Utilization	Optimized Generator Operation Deferred Generation Capacity Investments Reduced Congestion Cost
	T&D Capital Savings	Deferred Transmission Investments Deferred Distribution Investments
	Energy Efficiency	Reduced Electricity Losses
	Electricity Cost Savings	Reduced Electricity Cost
Reliability	Power Interruptions	Reduced Outages
	Power Quality	Improved Power Quality
Environmental	Air Emissions	Reduced CO_2 Emissions Reduced SO_X, Reduced NO_X Reduced Particulate Matter (PM) Emissions

Table 4. Market, Owner, Application to Benefit Mapping

Application	Market	Owner	Arbitrage Revenue	Capacity Market Revenue	Ancillary Services Revenue	Optimized Generator Operation (Non-Utility Merchant)	Optimized Generator Operation (Utility/Ratepayer)	Deferred Generation Capacity Investments	Reduced Congestion Costs (Non-Utility Merchant)	Reduced Congestion Costs (Utility/Ratepayer)	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost (Consumer)	Reduced Electricity Cost (Utility/Ratepayer)	Reduced Outages (Consumer)	Reduced Outages (Utility/Ratepayer)	Improved Power Quality	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
Electric Energy Time-shift	Regulated	Utility													P				S	S	S	S
Electric Energy Time-shift	Deregulated	Non-Utility Merchant/ IPP	P																S	S	S	S
Electric Supply Capacity	Regulated	Utility						P														
Electric Supply Capacity	Deregulated	Non-Utility Merchant/IPP		P																		
Load Following	Regulated	Utility					P	P														
Load Following	Deregulated	Non-Utility Merchant/ IPP			P																	
Area Regulation	Regulated	Utility						P														
Area Regulation	Deregulated	Non-Utility Merchant/ IPP			P																	
Electric Supply Reserve Capacity	Regulated	Utility					P												S	S	S	S
Electric Supply Reserve Capacity	Deregulated	Non-Utility Merchant/ IPP			P	S													S	S	S	S
Voltage Support	Regulated; Deregulated	Utility; Non-Utility Merchant/ IPP			P													P				
Transmission Support	Regulated; Deregulated	Utility									P						P					
Transmission Congestion Relief	Regulated	Utility								P	S											
Transmission Congestion Relief	Deregulated	Non-Utility Merchant/ IPP							P													
Transmission & Distribution (T&D) Upgrade Deferral	Regulated; Deregulated	Utility									P	P										
Time-of-use (TOU) Energy Cost Management	Regulated; Deregulated	End-User												P								
Demand Charge Management	Regulated; Deregulated	End-User												P								
Electric Service Reliability	Regulated; Deregulated	Utility															P					

Application	Market	Owner	Arbitrage Revenue	Capacity Market Revenue	Ancillary Services Revenue	Optimized Generator Operation (Non-Utility Merchant)	Optimized Generator Operation (Utility/Ratepayer)	Deferred Generation Capacity Investments	Reduced Congestion Costs (Non-Utility Merchant)	Reduced Congestion Costs (Utility/Ratepayer)	Deferred Transmission Investments	Deferred Distribution Investments	Reduced Electricity Losses	Reduced Electricity Cost (Consumer)	Reduced Electricity Cost (Utility/Ratepayer)	Reduced Outages (Consumer)	Reduced Outages (Utility/Ratepayer)	Improved Power Quality	Reduced CO2 Emissions	Reduced SOx Emissions	Reduced NOx Emissions	Reduced PM Emissions
Electric Service Reliability	Regulated; Deregulated	End-User														P						
Electric Service Power Quality	Regulated; Deregulated	End-User																P				
Renewables Energy Time-shift	Regulated	Utility													P				S	S	S	S
Renewables Energy Time-shift	Deregulated	Non-Utility Merchant/IPP	P																S	S	S	S
Renewables Energy Time-shift	Regulated; Deregulated	End-User												P					S	S	S	S
Renewables Capacity Firming	Regulated	Utility						P											S	S	S	S
Renewables Capacity Firming	Deregulated	Non-Utility Merchant/IPP		P															S	S	S	S
Wind Generation Grid Integration - Short Duration	Regulated	Utility						P											S	S	S	S
Wind Generation Grid Integration - Short Duration	Deregulated	Non-Utility Merchant/IPP		P															S	S	S	S
Wind Generation Grid Integration - Long Duration	Regulated	Utility													P				S	S	S	S
Wind Generation Grid Integration - Long Duration	Deregulated	Non-Utility Merchant/IPP	P																S	S	S	S

2.4 Benefit Calculations

The last step in quantifying a project's total benefit is to apply calculations which monetize ES impacts. All data that the ESCT uses to calculate benefits must be collected and entered into the tool by the user. The ESCT is designed to enable project teams to analyze and project benefits of their deployment based on existing project experience and system data. For example, in order to calculate the monetary value of the energy arbitrage benefit a user must enter data specific to their deployment and service territory such as: total amounts of energy stored annually for arbitrage purposes; storage device round-trip efficiency; and the annual average energy prices at peak and off-peak. These inputs are used to quantify the benefit for the first couple of years of the deployment and then the benefits are projected into the future using various escalation factors.[2]

If the user does not have measured data to enter, they can leverage default values for most of the inputs. However, if default values are used the user should take care in interpreting the results since the default values tend to be general estimates, and the actual values for the user's project may vary greatly. Furthermore, default values do not take into account situations in which energy storage deployments are being used for multiple applications, rather they assume the storage is being used for a single application for an entire year. Therefore, if multiple applications are being pursued and default values are being used, the user must ensure that the default amount of energy discharge for each application is realistic considering that the storage is being used for more than one application throughout the year. To view the sources and equations used to populate the default values see section D.1 Default Values for Inputs in Appendix D: Detailed Explanations of Inputs and Escalation.

The final aspect of benefit calculation 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.).

2.5 Cost Calculations

The ESCT expresses all benefits and cost in present value terms. The user enters total project capital costs and yearly O&M costs along with the discount rate, inflation rate, and fixed charge rate into the tool. The tool then amortizes the costs over the project lifetime in order to determine a cost schedule. At the end of the project lifetime the ESCT can also take into consideration the decommissioning and disposal costs. The present value of the project cost is subtracted from the present value of the total benefits to determine a project's net present value (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, this approach allows users to compare a high-level approximation of a project's future costs and benefits. This high-level comparison provides a context for interpreting the overall benefits and value of a project.

See Appendix D: Detailed Explanations of Inputs and Escalation, for a more detailed explanation of the escalation techniques used in the ESCT.

3.0 Architecture and Design

3.1 Design Principles

The ESCT 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 ES assets and applications. The tool is intended for users with a basic understanding of ES technologies and terms. The assumptions and calculation methodologies are documented in the appendices. Because ES 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 updates to incorporate other ES technologies, applications, benefits, or equations.

3.2 Architecture

Figure 2 illustrates the overall architecture of the ESCT. Although the tool is contained in a single Excel™ file, it has three distinct modules. The architecture of the tool is based on a modular structure that ensures ease of use and allows the tool to be more easily updated. Module I is the Asset Characterization Module (ACM), Module II is the Data Input Module (DIM), and Module III is the Computational Module (CM).

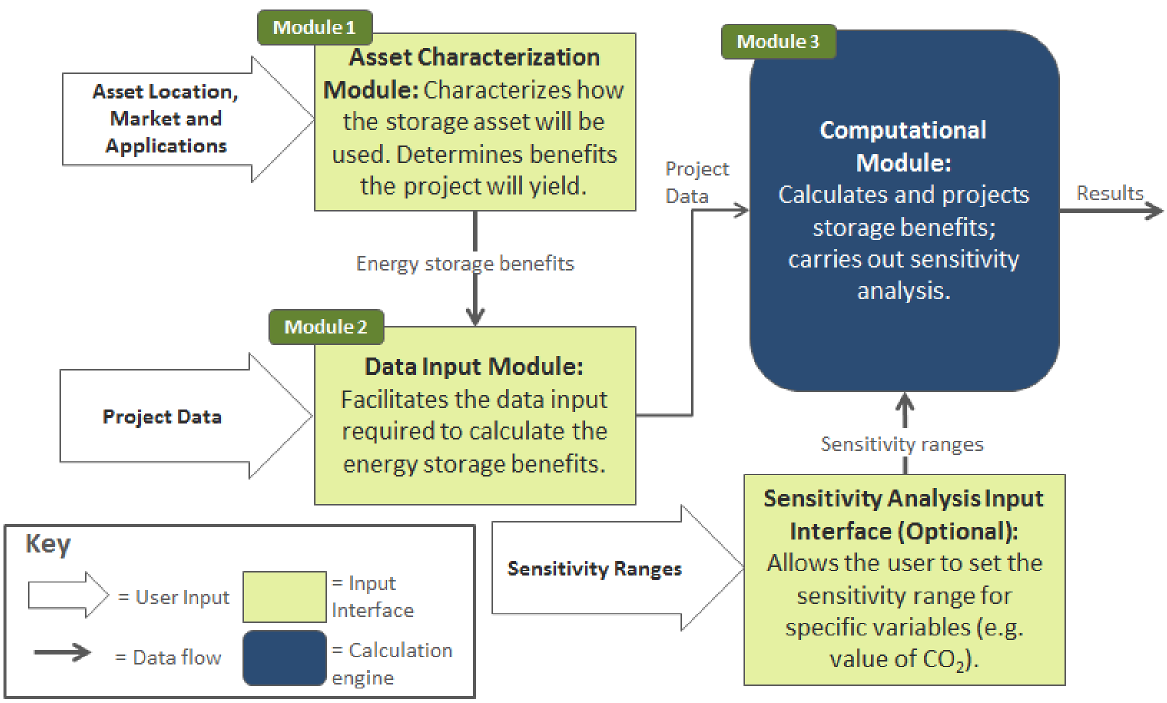

Figure 2. ESCT Architecture

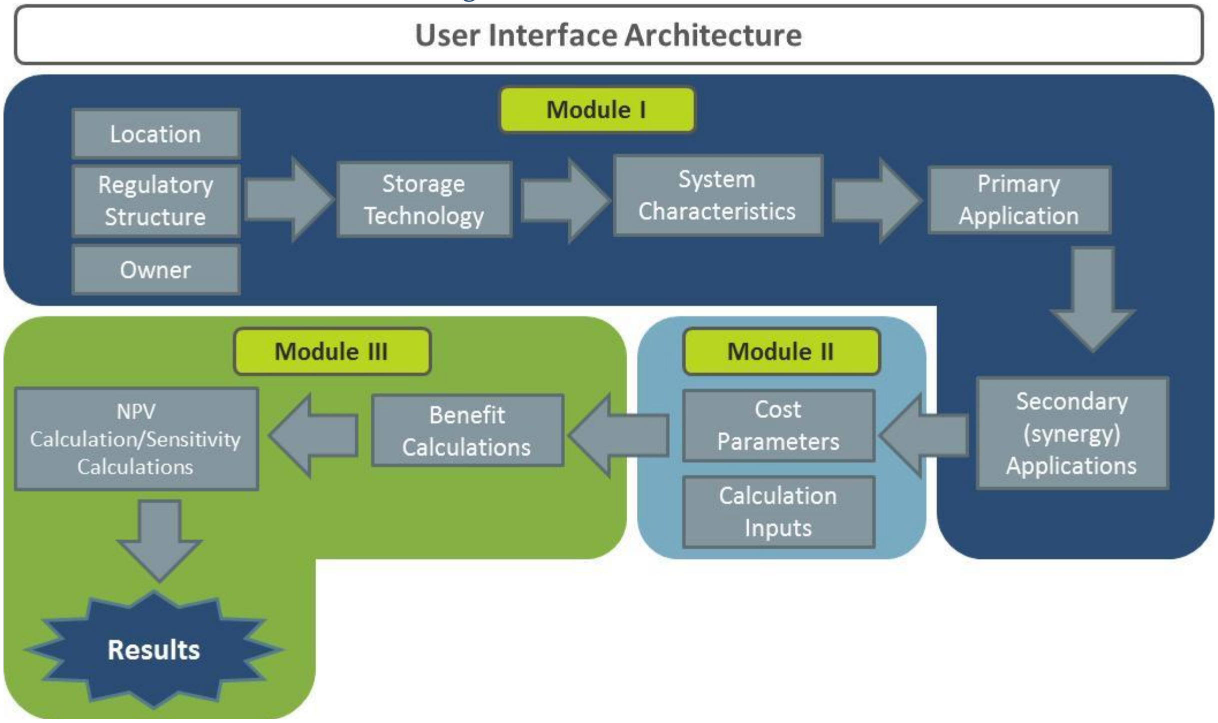

Figure 3 illustrates how the user experiences the tool. The interface is principally designed to help the user navigate the complex tool in a way that is transparent, easy to follow, and in a way that will minimize errors and make it easy to track down errors if they are made

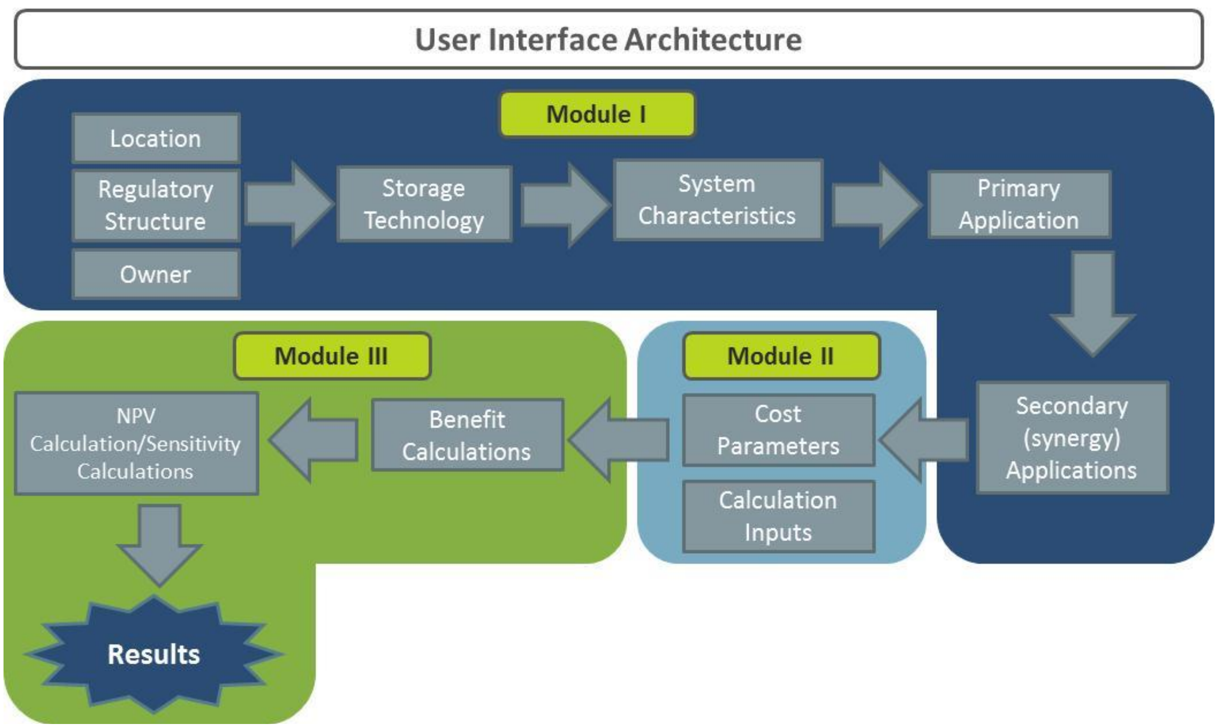

Figure 3. User Interface Architecture

Although the user experiences the ESCT in a linear fashion, there are many non-linear interdependencies among the various inputs, which are illustrated in Figure 4. For example, project characteristics specified in Asset Characterization Module such as location, market, and owner, influence the type of benefit calculations used later on in the Computational Module.

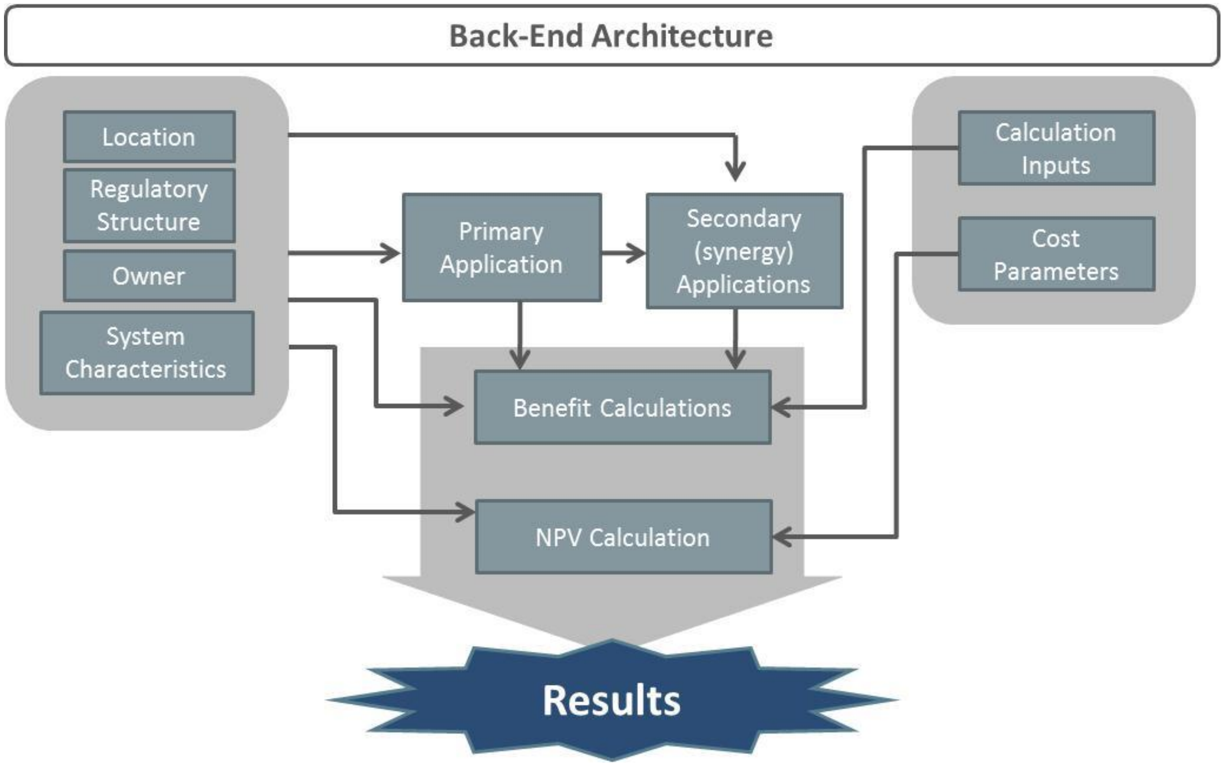

Figure 4. Back-End Architecture

3.2.1 Asset Characterization Module (ACM)

The ACM identifies the benefits that the ES deployment can yield, based on user-entered ES asset characteristics, technical parameters, location, market, owner and applications. First, the user identifies the assets and technical parameters of the assets that will be installed. The user also specifies the location of the deployment, the market in which it is deployed, and the owner. Based on these inputs the ACM determines the applications that the deployment could potentially support. Then, the ACM presents the user with a subset of possible applications and prompts the user to specify which primary application will be pursued by the project. Next, the ACM prompts the user to specify additional secondary applications[3] (up to two) that will be pursued in the project. Finally, the ACM displays a list of benefits that the project will yield along with an application-benefit map which the user must verify before advancing to the next phase of the tool, the Data Input Module.

3.2.2 Data Input Module (DIM)

The DIM facilitates the entry of required inputs. The DIM determines the required inputs based on the benefits identified by the ACM. From the dozens of inputs that are required to calculate all of the various benefits, the DIM prompts the user only to enter those inputs that are relevant to the benefits that the project enables.

[3] The tool does not automatically calculate or provide guidance with regard to the portion of time the ES unit is used for the various secondary applications. All benefits associated with the secondary applications can be analyzed by the user and it is the user's responsibility to enter measured or estimated data that takes into account the extent to which the storage unit is used for the primary and secondary applications.

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

» EIA (Annual Energy Outlook 2010-11, 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.)]
» Sandia Report SAND2010-0815 "Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide "

To view the sources and equations used to populate the default values see section D.1 Default Values for Inputs in Appendix D: Detailed Explanations of Inputs and Escalation.

Before allowing the user to proceed to the next module in the tool, the inputs are checked for errors and completeness. If the DIM detects errors or omissions in data entry, a message will appear which requests 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. If you have entered values for certain key metrics that are deemed unrealistic based on the storage capacity and efficiency characteristics, a warning textbox will appear. However, the ESCT will allow you to proceed to the next phase in spite of these warnings. If you believe a warning is valid and wish to modify your inputs, you should navigate back to the DIM to do so. Detailed explanations of the criteria that lead to these warnings are located in section D.2 Criteria for Data Input Warning Flags. Once all required data are entered, they are fed to the Computational Module (CM), the tool presents summaries of the final input data to the user, and the CM main interface is loaded.

3.2.3 Computational Module (CM)

The CM is the calculation engine of the ESCT. The primary purpose of the CM is to transform the inputs from the DIM into the costs and benefits of the ES 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 a maximum of 40 years beyond the initial year of analysis. Depending on the inputs, the CM uses different techniques and escalation factors to create forecasts. Escalation factors include load growth, and inflation. In some cases, the default escalation factor is zero for years beyond the last year for which data was entered. The user can review and change all escalation factors at run time in the ACM. For a detailed explanation of the forecasting methods used for each parameter in the ESCT, please see Appendix D.

The CM also includes a sensitivity analysis module. The user can set low and high sensitivity values to explore how benefits and costs of the ES 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 Detailed Instructions for using the ESCT

4.1 Getting Started

The ES Computational Tool performs best when used in Excel™ 2007, but may also be used with Excel™ 2003. No additional programs or add-ins are required. 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 tool is saved to your local hard drive, it can be used as the template for all future analyses. To start a new analysis, open the tool and save the file as a new, uniquely named version on your computer. When you open the ESCT, you will see the "Introduction" tab, pictured in Figure 5. The Start tab provides a brief introduction to the ESCT, 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 "Begin the ESCT" button. Clicking this button will initiate a new analysis by launching the ACM.

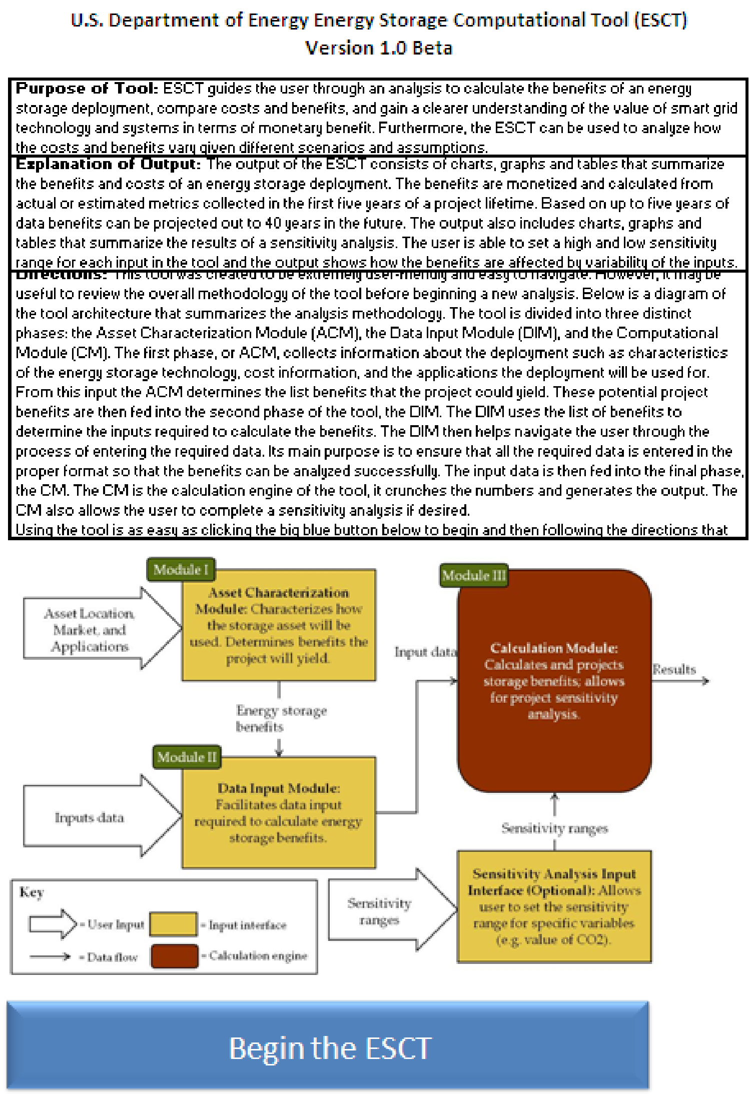

Figure 5. The ESCT "Introduction" tab

4.2 Creating a New Analysis

4.2.1 Asset Characterization Module (ACM)

The ACM utilizes a series of graphic user interface screens to collect data and help the user navigate through the module. Figure 6 and Figure 7 depict two typical examples of screens that will appear in the ACM. Several common elements appear in all or most of the screens. All screens have navigation buttons at the bottom that enable you to proceed forward or backward through the screens, as well as an "Exit" button that will end the analysis. All screens also have directions across the top. Data is entered by selecting radio buttons, selecting items from drop downs, selecting check boxes, or entering data directly into text boxes. Buttons may also appear on the screens that either provide you with definitions or enable you to take advantage of default values.

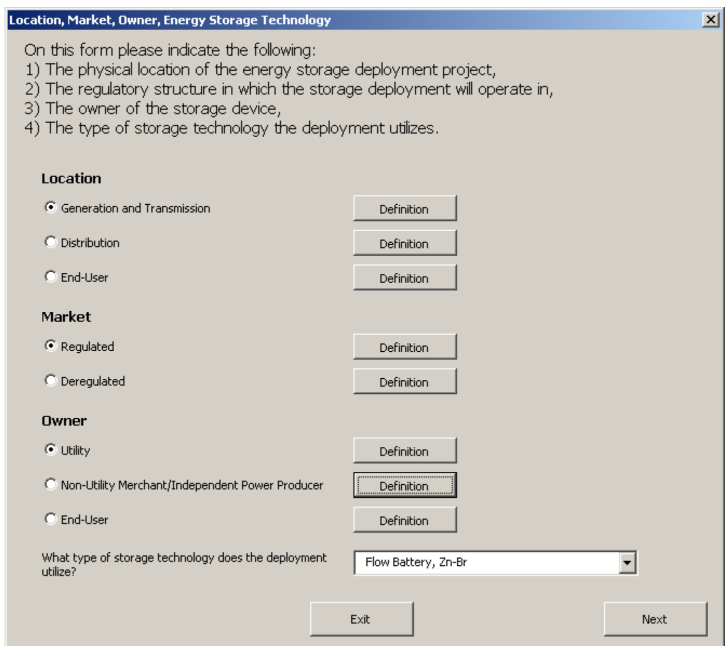

Figure 6. Typical ACM screen: Example 1

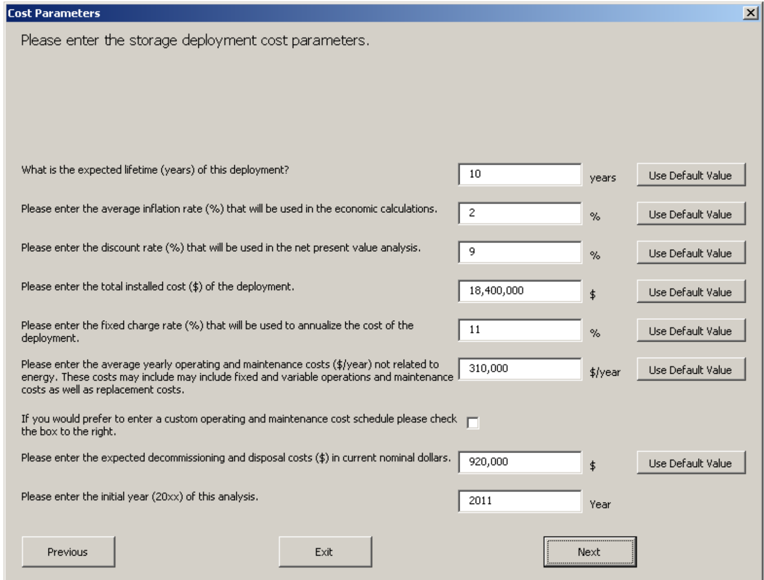

Figure 7. Typical ACM screen: Example 2

Once you have entered all the required inputs for a screen simply click the "Next" button to advance to the next screen. The final screen of the ACM, depicted in Figure 8, displays the benefits that the project is expected to yield based on all the inputs entered on the previous pages. You can review an explanation of each benefit by clicking the "Definition" buttons.

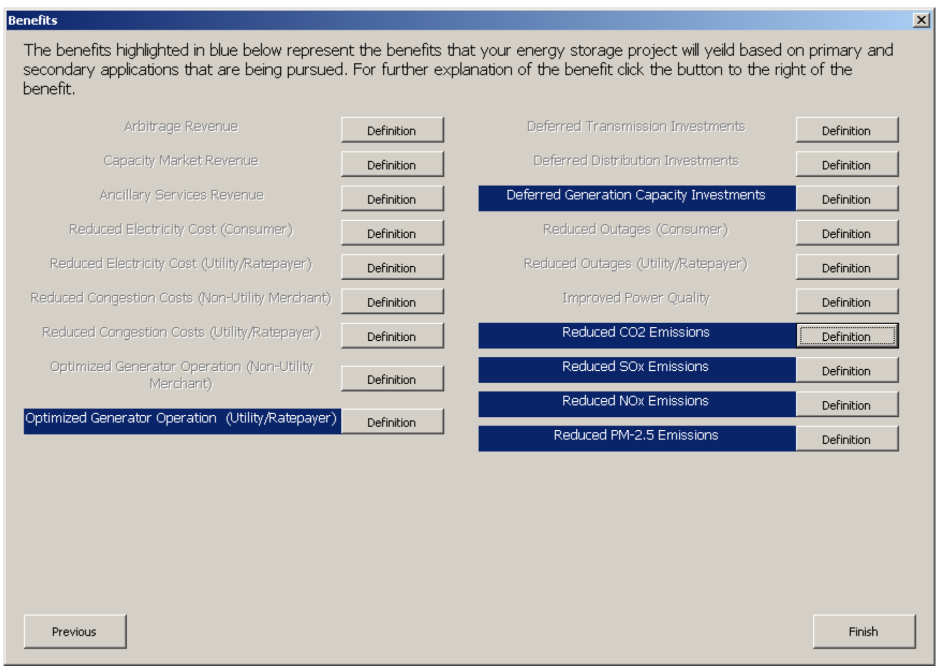

Figure 8. The final ACM Screen: The Benefits Summary Screen

You should carefully review the benefits the ESCT has selected before proceeding. In the next phase of the ESCT, the DIM, you will enter the inputs required to quantify the benefits highlighted in blue. If you are not satisfied with the benefits list, use the "Previous" buttons to navigate back through the preceding ACM screens to alter your selections.

Once you are satisfied with the benefits listed on the ACM Benefits Screen, click the "Finish" button to complete the Asset Characterization Module.

The ESCT will prompt you to save the file, which is recommended. 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 ESCT on your computer for additional analyses.

If you chose to enter a custom maintenance cost schedule in the ACM, the tool will present you with an Excel™ tab called the "Maintenance Schedule". This tab is depicted in Figure 9. After entering the yearly maintenance costs into the table that appears in this tab, click the "Finish Entering Custom Cost Schedule" button to proceed. If you decide you do not want to enter a custom maintenance schedule, you can click the other button to return to the ACM and enter a single yearly maintenance cost number, which will be used in the cost calculations for all analysis years.

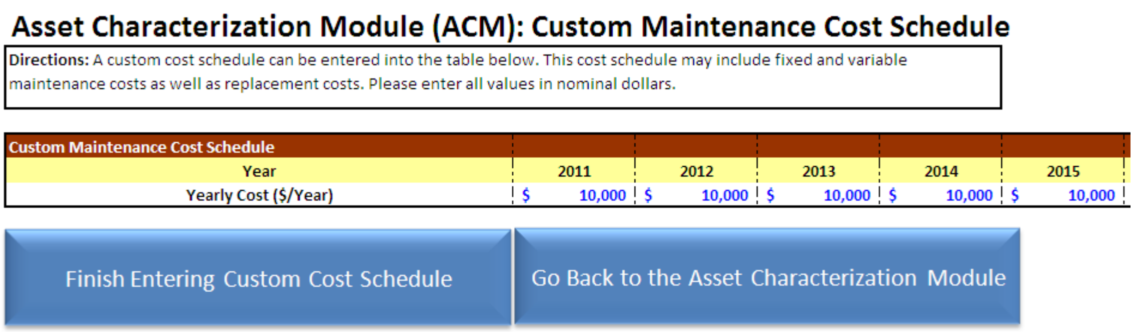

Figure 9. Custom maintenance cost schedule tab

The next Excel™ tab that the ESCT presents is called "Application Benefit Summary" (see Figure 10). This tab presents an Application-Benefit summary map that is specific to the project under analysis. This map allows you to see a summary of how the applications of the project map to the benefits. This information provides deeper insight into how benefits and applications are linked. This tab also serves as a last visual check before moving into the Data Input Module phase of the ESCT. If the highlighted applications or benefits in the chart fail to accurately represent your project, you can click the button at the top that reads "Return to the Assets Characterization Module (ACM)". This will return you to the first screen of the ACM 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.

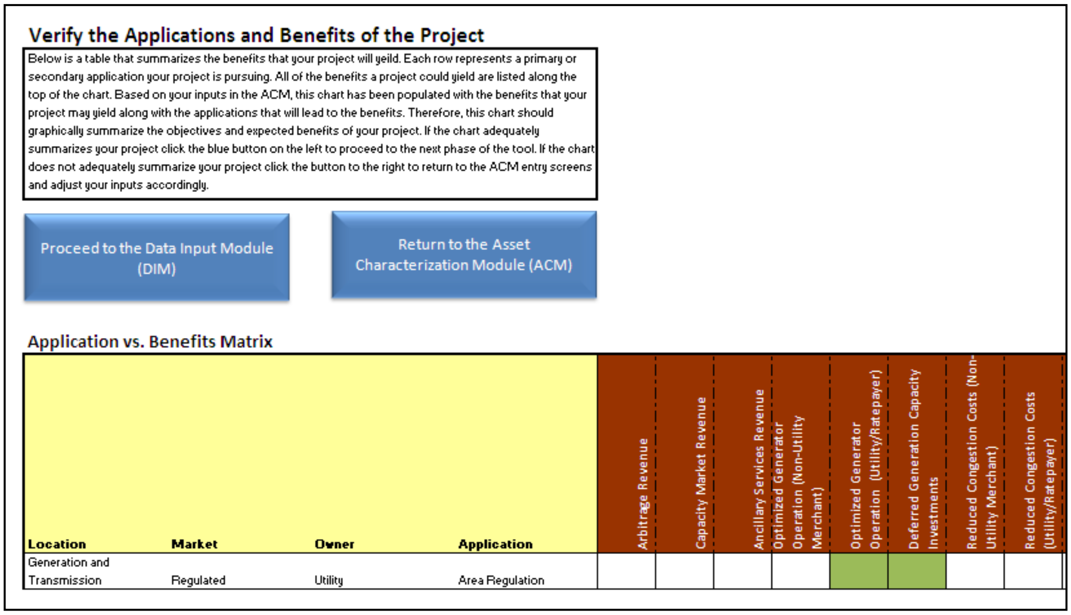

Figure 10. The Application-Benefit Summary Map

If the chart accurately represents the project under analysis, click the button "Proceed to the Data Input Module (DIM)". This will end the ACM phase, and bring you to the "Data Input Module" tab, which is the first and primary tab of the DIM phase.

4.2.2 Data Input Module (DIM)

The "Data Input Module" tab, depicted in Figure 11, provides you with a table to enter all the data required to calculate the benefits of the project. The input table contains the input name, the units of the input, and a definition of each input. Most inputs have a set of default values that can be leveraged in the event that user-provided estimates or actual project data are unavailable. To use the default values select the "Use Default" option from the drop down lists in the "Default Values" column. To view the sources and equations used to populate the default values see section D.1 Default Values for Inputs in Appendix D: Detailed Explanations of Inputs and Escalation. You should enter at least one year of data for each input listed in the table. The ESCT will not allow you to advance until all required data is entered into the table. If you decide that you want to go back to the ACM and change your inputs you can click the blue button at the top of the page.

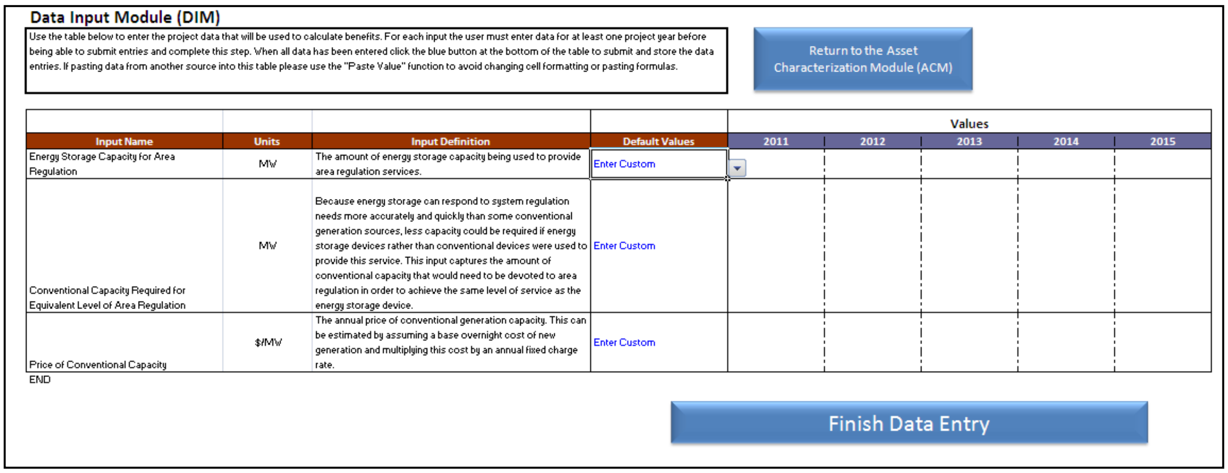

Figure 11. The Data Input Module tab

Once you have entered all the required data, 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 input correctly. If all required data haven't been correctly entered, a message explaining which data are still required will be displayed.

After clicking the "Finish Data Entry" button at the bottom of the "Data Input Module" tab, two tabs will appear. One tab, the "Input Review" tab, summarizes all the inputs that the user entered along with the first five years of projected data that will be used in the benefit calculations. The data input review page will remain visible so you can review your inputs at any time. The other tab that appears is the "CM Main Page" tab. As its name suggests this is the main page for the next module of the ESCT.

4.3 Saving and Updating an Existing Analysis

At this point, all of the required inputs have been entered into the ESCT. 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 to update inputs or input new data for the years for which data hadn't been previously available. You can also revisit the ACM module if additional applications have been pursued and you want to analyze the benefits of those applications.

4.4 Running the Computational Module (CM)

The CM Main page is depicted in Figure 12 below. 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 20 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 40 seconds 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 ACM and/or DIM, all CM analyses should be re-run.

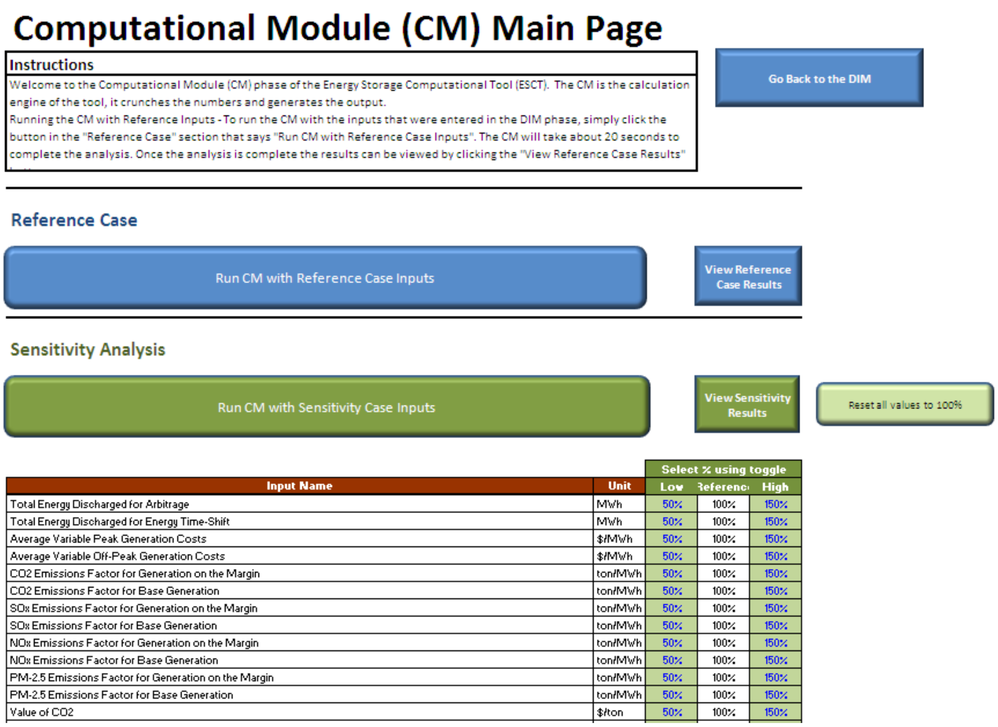

Figure 12. The CM Main Page

4.5 Reviewing the ESCT 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, a Net Present Value (NPV) analysis, and an Additional Benefits table. Sensitivity Case Results include bar 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 benefit sub-category (e.g. Market Revenue, Improved Asset Utilization, etc.). All values are in present value terms.

Result Charts – This page contains a pie chart and the underlying table that summarize the total cumulative benefits over the entire analysis period. All values are in present value terms. This page also contains a table and two graphs that visualize the project’s benefits and costs in present value terms over the entire project lifetime. The tables contains the annual and cumulative costs and benefits in present value terms as well as the annual and cumulative net benefit (the difference between the present value of costs and benefits) of the project in present value terms. The top graph shows the annual values while the bottom graph shows the cumulative values.

Additional Benefits – This page contains a table that lists all of the additional benefits that might be achieved by the deployment along with an explanation of the rationale that could lead to that benefit. At this point in the analysis, these benefits are only captured qualitatively for reasons explained in section 2.3 Relationships of Applications to Benefits. If after reading the explanation the user wishes to calculate the value of the benefit, they can click a link that will open an additional worksheet that will collect the additional inputs required to monetize these benefits.

Sensitivity Case Results

Result tables Sensitivity Cases – The tables on this page summarize the annual value of all the benefits and costs over the entire analysis period for the low case and high case.

Sensitivity Graphs – This page contains a bar chart that compares the total gross benefits over the deployment period for the reference, low and high case. This page also features a table that contains all of the values used to create the bar chart.

4.6 Conclusion

The ESCT identifies the applications to be demonstrated by an ES deployment, and helps the user analyze the costs and benefits to determine the deployments overall value. By using this tool, interested parties can determine project costs and benefits to gain a clearer understanding of the financial benefits of an ES deployment. Furthermore, interested parties will be able to use the ESCT to analyze costs and benefits of ES deployments under different scenarios and assumptions.

The monetary value of the benefits calculated by the ESCT could be attributed to ratepayers/utilities, non-utility merchants, end-users, society, or a combination of these parties depending on the nature of the deployment and the applications pursued. The primary and secondary benefits that the ESCT calculates are assumed to accrue to the owner unless otherwise specified in the name of the benefit.[4]

[4] All emissions benefits are assumed to accrue to society at large, unless a market for emissions exists. The additional benefits typically accrue to stakeholders that are not the owner of the ES.

However, in determining the total value of the project the ESCT aggregates all benefits regardless of who the likely benefactor is. Therefore, if the user wishes to carry out a more detailed cost-benefit analysis that is specific to them, they must designate which of the various benefits accrue to them specifically and complete this analysis separately. The tool was not specifically designed to yield results to 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 an ES deployment.

Appendix A: Asset, Application, and Benefit Descriptions

Table 5. Descriptions of Assets

Asset	Description
Battery	A battery storage device uses an electrochemical reaction to store energy. Many different types of battery are available, and lead acid, sodium sulfur, and lithium ion batteries are the most common for ES on a grid level. Batteries, with capacities under 10MWh, are usually not large enough for storage of the output of entire power plants, but they can provide rapid storage and discharge of smaller amounts of energy for multiple-minute time shift and ancillary service applications.
Compressed Air ES	A compressed air ES (CAES) device uses the physical potential energy in compressed air as its storage medium. An air compressor raises the pressure of air in a closed space, either an aboveground tank or an underground cavern, and then releases the stored air to power a gas turbine. CAES devices are generally used for large-scale storage (>10MWh) of energy over multiple hour periods. These devices have a response time slightly faster than conventional gas generators, but generally offer lesser ancillary services benefits compared to fast-response ES such as batteries.
Flow Battery	A flow battery storage device uses an electrolyte fluid in a fuel cell to reversibly store and create energy. Flow batteries are generally in the research and development stage. Similar to batteries, flow batteries can store small to medium amounts of energy (<5MWh) and provide storage and discharge for ancillary services.
Flywheel ES	A flywheel ES device uses a mechanical flywheel to physically store and discharge energy. Flywheels generally have a small energy capacity (<5MWh) but have a high power capacity and very rapid response time, and are thus best suited for provision of ancillary services.
Pumped Hydro Storage	A pumped hydro storage unit uses the potential physical energy of water as its storage medium, providing ES by pumping water uphill, and discharging by allowing the water to flow through a turbine. Pumped hydro storage is capable of a very large energy capacity, depending on location, but generally cannot deliver a high power capacity. Pumped hydro is thus best suited for large-scale (>100MWh) time shifting.
Supercapacitor	Supercapacitors (also known as ultracapacitors) are a specialized adaptation of the capacitors used in distribution systems. Supercapacitors can provide extremely rapid storage and discharge for very small amounts of energy (<100kWh), making them ideal for specialized ancillary service applications.

Table 6. Descriptions of Applications

Application	Description
Electric Energy Time-shift	The electric Energy Time-shift (time-shift) application involves storing electricity when the price of electricity is low and discharging that electricity when the price of electricity is high. The energy that is discharged from the ES could be sold via the wholesale market, sold under terms of a power purchase agreement, or used by an integrated utility to reduce the overall cost of providing generation during peak times.
Electric Supply Capacity	As demand on the electricity grid grows from year-to-year, the need to install additional generation capacity to meet this demand also grows. The Electric Supply Capacity application involves using ES to defer and/or to reduce the need to invest in new generation capacity. In a regulated market, a utility may install a marginal amount of ES to meet capacity needs thus deferring the need to invest in a larger conventional generation solution. In a deregulated market, where the electric supply capacity market is evolving, this application could involve selling ES capacity to the market in order to generate a capacity credit revenue stream for a non-utility merchant. However, this market is evolving and in some markets, generation capacity cost is included in wholesale energy prices.
Load Following	Load following is an ancillary service concerned with maintaining grid balance by adjusting power as demand for electricity fluctuates throughout the day. Load following operates on a time scale of about 10 to 15 minutes. In a deregulated market, this may not be a separate ancillary service depending on the mix of generation and the structure of the energy market in the area. If there is sufficient generation mix in the area that is flexible enough (i.e. able to ramp up quickly enough to meet the system need) to meet the system load following needs then this balancing can be effectively accomplished through the energy market. Additionally, sub-hourly energy markets allow system operators to do a great deal of balancing through energy markets without having to explicitly purchase additional control services. In a deregulated market the Load Following application can involve using energy storage to participate in the market for load following services (if such a market exists). In a regulated market, energy storage rather than conventional generation can be used to provide this service. This can provide a benefit with two possible elements: a capacity element and a marginal cost element. The capacity element involves reducing the cost associated with installing additional generation capacity to provide this service. Finally, providing this service with energy storage may yield a marginal cost benefit if partial load operation of conventional generation is reduced (part load operation typically leads to sub-optimal generator performance in terms of heat rate and therefore leads to higher marginal costs).
Area Regulation	Area regulation is an ancillary service to reconcile momentary differences between supply and demand. This service is provided by on-line generation equipped with automatic generation control (AGC) that can change output quickly to track the moment-to-moment fluctuations in customer loads and correct for the unintended fluctuations in generation. Regulation helps maintain interconnection frequency, manage differences between actual and scheduled power flows between balancing areas, and match generation to load within the balancing area. In a deregulated market this application involves using ES to participate in the market for area regulation services. In a regulated market, using ES for frequency regulation can yield operational benefits because it eliminates the need for the conventional generator to cycle constantly. This may improve the heat rate of the generation

Application	Description
	unit and result in fewer emissions. It may also improve the marginal cost to operate that generation. Because ES can respond to system regulation needs more accurately and quickly than conventional generation sources, conventional capacity could be freed up to meet energy needs.
Electric Supply Reserve Capacity	Electric supply reserve capacity is an ancillary service to maintain extra capacity that can be called upon when some portion of the normal electric supply resources become unavailable unexpectedly. There are three generic types of reserve capacity: spinning reserve, non-spinning reserve, and backup supply. In a deregulated market this application involves using ES to participate in the market for these services. In a regulated market, using ES to replace traditional spinning reserve can yield operational benefits because it obviates the need to operate a conventional unit at partial load so that it is ready to provide capacity in the event of an outage. This may improve the heat rate of the generation unit and result in fewer emissions. It may also improve the marginal cost to operate that generation.
Voltage Support	Voltage support is an ancillary service concerned with managing a phenomenon called reactance, so that grid system voltage can be restored or maintained. Reactance is a localized phenomenon that occurs because equipment that generates, transmits, or uses electricity simultaneously injects or withdraws reactive power into the system. Voltages are sensitive to, and controlled by, reactive power on the system and must be maintained within tight ranges to protect customer and utility equipment and to prevent voltage collapse and outages. Historically voltage support has been provided by generation resources. However, because reactive power is a localized phenomenon and because it cannot be transmitted effectively over long distances, those generation resources must be located in the right region to be able to manage reactance. Reactance can be managed in more distributed ways as well with capacitors, inductors and transformer tap changes, but these solutions are slow to respond and can actually exacerbate voltage related problems during contingency conditions. The Voltage Support application involves using ES assets to provide distributed or centralized voltage support. Storage is well suited for this application because it is quick to respond, can be sited where it is needed, and can effectively provide voltage support during contingency conditions. An ES device used for this application could yield a revenue stream by participating in the market for this service. Finally, using distributed ES systems to provide voltage support could improve the power quality of the system.
Transmission Support	The Transmission Support application involves using ES to provide a suite of ancillary services concerned with improving T&D system performance by compensating for electrical anomalies and disturbances such as voltage sag, unstable voltage, and sub-synchronous resonance. The result is a more stable system with improved performance. This application is similar to the ancillary service referred to as Network Stability. Specifically, ES can be used to provide the following services: • Transmission Stability Damping – Power system stability limitations are often characterized by low frequency oscillations (0.5 – 1 Hz) following a major system disturbance. Power transfers are often limited to prevent growing oscillations from occurring following loss of a single major transmission line or generator. When limited by long-term stability the transmission capacity can be increased by providing active damping of these oscillations. ES devices can actively dampen

Application	Description
	these system oscillations through modulation of both real and reactive power. Using ES to provide this service can defer the need to invest in additional transmission capacity. • Under-frequency Load Shedding Reduction – When the power system suffers the loss of a major resource such as a generating plant or major importing transmission lines, the system frequency will drop and continue to decline until the generating resource/load balance is restored. Because ES can inject real power rapidly into the system, it is an effective method to offset, or reduce, under frequency load shedding because it reduces the mismatch between load and supply capability that takes place because of the system disturbance. Therefore, using ES to provide this service can result in a reliability benefit.
Transmission Congestion Relief	In areas where transmission capacity is not sufficient to transmit the lowest cost generation to market, congestion will occur on these systems during periods of peak demand, leading to increased transmission access charges. This market phenomenon is known as congestion. The Transmission Congestion Relief application involves using ES to avoid congestion-related costs and charges by locating storage electrically downstream from the congested portion of the transmission system. Energy would be stored when there is no transmission congestion, and it would be discharged (during peak demand periods) to reduce transmission capacity requirements.
Transmission & Distribution (T&D) Upgrade Deferral	Transmission and Distribution (T&D) Upgrade Deferral application involves installing ES in order to delay transmission and/or distribution system upgrades. The value of this application is derived from the fact that storage can be used to provide enough incremental capacity to defer the need for a large 'lump' investment in T&D equipment. If using an energy storage device to defer a T&D investment proper consideration must be given to reliability. T&D capital investments must maintain the extremely high reliability of the electric delivery system. Therefore, any energy storage solution that defers the need for a T&D investment must similarly maintain the reliability of the system. For energy storage deployments this means ensuring that the storage solution has enough redundancy or modularity such that the effective reliability of the solution is adequate.
Substation On-site Power	The Substation On-site Power application involves using new ES systems provide power to switching components and to substation communication and control equipment when the grid is not energized. Benefit would be realized to the extent that the new systems reduce the need for routine maintenance, improved reliability, provide longer battery life, would make alternatives attractive, especially if the cost is comparable to that of the incumbent technologies. This application is not quantified in the tool.
Time-of-use (TOU) Energy Cost Management	For the Time-of-use (TOU) Energy Cost Management application, energy end users (utility customers) would use ES devices to reduce their overall costs for electricity. They would accomplish this by charging the storage during off-peak periods when the electric energy price is low, then discharge the energy during times when on-peak TOU energy prices apply. This application is similar to Electric Energy Time-shift application, although electric energy savings are based on the customer's retail tariff, whereas the benefit for Electric Energy Time-shift is based on the prevailing wholesale price.
Demand Charge Management	For the Demand Charge Management application, energy end users would use storage to reduce the overall costs for electric service by reducing demand charges. Using storage to reduce their power draw during specified periods (demand charge

Application	Description
	periods), end users can lower the costs that are tied to the amount of load (kW) they demand from the grid.
Electric Service Reliability	The Electric Service Reliability application involves using ES to ensure highly reliable electric service. In the event of an extended system disruption, ES can be used to ride through the outage, complete an orderly shutdown, or transition to on-site generation.
Electric Service Power Quality	The Electric Service Power Quality application involves using ES to protect on-site loads downstream from storage against short-term duration events affecting power quality. Manifestations of poor power quality include variations in voltage magnitude, variations in the primary 60-Hz frequency at which power is delivered, and interruptions in service ranging from a fraction of a second to several minutes.
Renewables Energy Time-shift	The Renewables Energy Time-shift application involves storing electricity from renewable sources when the price of electricity is low and selling that stored energy when the price of electricity is higher. Because wind typically produces energy at night when electricity prices are low, the price differential between the electricity used to charge the battery and the electricity sold at peak can be very large. The energy that is discharged from the storage could be sold via the wholesale market, sold under terms of an energy purchase contract, or used by an integrated utility to reduce the overall cost of providing generation during peak times.
Renewables Capacity Firming	The Renewables Capacity Firming application involves using energy storage to enable the power output from intermittent renewable energy resources to be more consistent by providing energy when the power output from these sources drops temporarily. In a regulated market, firming renewable resources may enable a utility may defer the need to invest in additional conventional generation. In a deregulated market, where the electric supply capacity market is evolving, firming a renewable generation resource could enable a non-utility merchant to sell additional renewable energy capacity into the market resulting in a larger capacity credit revenue stream. However, this market is evolving and in some markets, generation capacity cost is included in wholesale energy prices.
Wind Generation Grid Integration - Short Duration	As wind generation penetration increases, the electricity grid effects that are unique to wind generation will also increase. Storage could assist with orderly integration of wind generation by managing or mitigating the more challenging and less desirable effects from high wind generation penetration. The Wind Generation Grid Integration (Short Duration) application involves using storage to mitigate short-duration effects such as output volatility and poor power quality.
Wind Generation Grid Integration - Long Duration	As wind generation penetration increases, the electricity grid effects that are unique to wind generation will also increase. Storage could assist with orderly integration of wind generation by managing or mitigating the more challenging and less desirable effects from high wind generation penetration. The Wind Generation Grid Integration (Long Duration) application involves using storage to mitigate long-duration effects such as output volatility, transmission congestion, backup for generation shortfalls, and minimum load violations.

Table 7. Power and Discharge Duration[5] Ranges by Application

Application	Storage Power Low Range (kW)	Discharge Duration Low Range
Electric Energy Time-shift	1,000	2 hr
Electric Supply Capacity	1,000	2 hr
Load Following	1,000	2 hr
Area Regulation	1,000	15 min.
Electric Supply Reserve Capacity	1,000	1 hr
Voltage Support	1,000	15 min.
Transmission Support	10,000	2 sec.
Transmission Congestion Relief	1,000	2 hr
Transmission & Distribution (T&D) Upgrade Deferral	250	2 hr
Substation On-site Power	1.5	8 hr
Time-of-use (TOU) Energy Cost Management	1	2 hr
Demand Charge Management	50	2 hr
Electric Service Reliability	0.2	5 min.
Electric Service Power Quality	0.2	10 sec.
Renewables Energy Time-shift	1	2 hr
Renewables Capacity Firming	1	1 hr
Wind Generation Grid Integration - Short Duration	0.2	1 hr
Wind Generation Grid Integration - Long Duration	0.2	2 hr

[5] Applications are not eliminated from consideration in the tool if their power or discharge durations exceed the maximum values listed in this chart. The maximum values are listed here are meant to provide the user with examples of typical power and discharge ranges that are appropriate for the various applications.

Table 8. Application Synergies

Application	Synergies
Electric Energy Time-shift	• Electric Supply Capacity • Load Following • Area Regulation • Electric Supply Reserve Capacity • Voltage Support • Transmission Congestion Relief • Transmission & Distribution (T&D) Upgrade Deferral • Electric Service Reliability • Electric Service Power Quality
Electric Supply Capacity	• Electric Energy Time-shift • Area Regulation • Electric Supply Reserve Capacity • Voltage Support • Transmission Support • Transmission Congestion Relief • Transmission & Distribution (T&D) Upgrade Deferral • Electric Service Reliability • Electric Service Power Quality
Load Following	• Electric Energy Time-shift • Electric Supply Capacity • Electric Supply Reserve Capacity • Voltage Support • Renewables Capacity Firming • Wind Generation Grid Integration - Short Duration
Area Regulation	• Electric Energy Time-shift • Electric Supply Capacity • Electric Supply Reserve Capacity • Voltage Support • Renewables Capacity Firming • Wind Generation Grid Integration - Short Duration
Electric Supply Reserve Capacity	• Electric Energy Time-shift • Electric Supply Capacity • Load Following • Area Regulation • Voltage Support • Renewable Energy Time-Shift • Renewables Capacity Firming • Wind Generation Grid Integration - Short Duration • Wind Generation Grid Integration - Long Duration

Application	Synergies
Voltage Support	• Electric Energy Time-shift • Electric Supply Capacity • Load Following • Area Regulation • Electric Supply Reserve Capacity • Renewables Energy Time-shift • Renewables Capacity Firming • Wind Generation Grid Integration - Short Duration • Wind Generation Grid Integration - Long Duration
Transmission Support	• Area Regulation • Voltage Support • Electric Service Power Quality
Transmission Congestion Relief	• Electric Energy Time-shift • Electric Supply Capacity • Load Following • Area Regulation • Electric Supply Reserve Capacity • Voltage Support • Renewables Energy Time-shift • Wind Generation Grid Integration - Long Duration
Transmission & Distribution (T&D) Upgrade Deferral	• Electric Energy Time-shift • Electric Supply Capacity • Electric Supply Reserve Capacity • Voltage Support • Transmission Congestion Relief • Electric Service Reliability • Electric Service Power Quality • Renewables Energy Time-shift • Wind Generation Grid Integration - Long Duration
Time-of-use (TOU) Energy Cost Management	• Demand Charge Management • Electric Service Reliability • Electric Service Power Quality
Demand Charge Management	• Time-of-use (TOU) Energy Cost Management • Electric Service Reliability • Electric Service Power Quality

Application	Synergies
Electric Service Reliability	• Electric Energy Time-shift • Electric Supply Capacity • Load Following • Electric Supply Reserve Capacity • Voltage Support • Transmission Congestion Relief • Transmission & Distribution (T&D) Upgrade Deferral • Time-of-use (TOU) Energy Cost Management • Demand Charge Management • Electric Service Power Quality • Renewables Energy Time-shift • Renewables Capacity Firming • Wind Generation Grid Integration - Short Duration • Wind Generation Grid Integration - Long Duration
Electric Service Power Quality	• Time-of-use (TOU) Energy Cost Management • Demand Charge Management • Electric Service Reliability
Renewables Energy Time-shift	• Electric Supply Capacity • Area Regulation • Electric Supply Reserve Capacity • Voltage Support • Transmission Congestion Relief • Transmission & Distribution (T&D) Upgrade Deferral • Time-of-use (TOU) Energy Cost Management • Demand Charge Management • Electric Service Reliability • Electric Service Power Quality • Renewables Capacity Firming • Wind Generation Grid Integration - Short Duration
Renewables Capacity Firming	• Electric Supply Reserve Capacity • Voltage Support • Transmission Congestion Relief • Transmission & Distribution (T&D) Upgrade Deferral • Time-of-use (TOU) Energy Cost Management • Demand Charge Management • Electric Service Reliability • Electric Service Power Quality • Renewables Energy Time-shift • Wind Generation Grid Integration - Long Duration

Application	Synergies
Wind Generation Grid Integration - Short Duration	• Electric Supply Reserve Capacity • Voltage Support • Transmission Congestion Relief • Transmission & Distribution (T&D) Upgrade Deferral • Time-of-use (TOU) Energy Cost Management • Demand Charge Management • Electric Service Reliability • Electric Service Power Quality • Renewables Energy Time-shift • Wind Generation Grid Integration - Long Duration
Wind Generation Grid Integration - Long Duration	• Electric Supply Capacity • Area Regulation • Electric Supply Reserve Capacity • Voltage Support • Transmission Congestion Relief • Transmission & Distribution (T&D) Upgrade Deferral • Time-of-use (TOU) Energy Cost Management • Demand Charge Management • Electric Service Reliability • Electric Service Power Quality • Renewables Capacity Firming • Wind Generation Grid Integration - Short Duration

Table 9. Description of Benefits

Benefit	Description
Arbitrage Revenue	ES can be used to store electricity purchased when prices are low, during off-peak periods, and discharge when electricity prices are high during peak periods, resulting in a revenue stream for the storage owner.
Capacity Market Revenue	As demand on the electricity grid grows from year-to-year, the need to install additional generation capacity to meet this demand also grows. In a deregulated market, where the electric supply capacity market is evolving, ES capacity could sold to the capacity to the market in order to generate a capacity credit revenue stream for a storage owner.
Ancillary Services Revenue	In deregulated electric service territories there may be organized markets for ancillary services such as load following, area regulation, reserve capacity, voltage support, and black start. The ability of ES devices to rapidly charge and discharge to the grid enables them to effectively provide these services resulting in a revenue stream for the owner.
Optimized Generator Operation	Using ES to respond to changes in load by absorbing or discharging energy as needed by the system can enable generators to run closer to their optimum operating zone. Therefore, by smoothing the load curve that the generation fleet must meet, storage can improve generation performance as measured by improved heat rate efficiency and lead to lower operating costs.
Deferred Generation Capacity Investments	By shifting peak demand or providing ancillary services that are typically provided by conventional generation assets, ES can result in deferred generation capacity investment benefits. By shifting peak demand, less generation capacity will be required to meet the system needs and by providing ancillary services more generation capacity will be freed up to meet system energy needs.
Reduced Congestion Costs	If storage is located close to load centers it may be used to reduce congestion by charging during periods of no congestion and discharging during congested periods. Charging and discharging in this way will meet peak demands while reducing the amount of electricity that must be passed through the congested transmission pathways. If congestion can be reduced in this way the costs associated with congestion can also be reduced.
Deferred Transmission 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.
Deferred Distribution Investments	Electricity storage can be used to relieve load on overloaded feeders and distribution assets, potentially extending the time before upgrades or additions are required.
Reduced Electricity Losses	By charging electricity close to load centers during periods of low demand and discharging during peak demand period, ES can reduce the peak load on the grid. Because losses proportional to the square of current on the system, reducing peak load will result in a reduction of the total amount of electricity line losses on the system.

Benefit	Description
Reduced Electricity Cost (Consumer)	Electricity storage can be used to reduce the cost of electricity for a consumer by enabling the consumer to avoid peak-demand charges and peak electricity prices. A consumer can charge their device when prices are low and discharge the device when prices are high. Because high prices tend to coincide with peak-times, this activity will also lower the customer's overall peak usage, which will lead to additional savings if the customer has a demand charge associated with their tariff.
Reduced Electricity Cost (Utility/Ratepayer)	Charging ES when demand is low, and discharging the devices when demand is high may decrease a utilities energy costs by allowing the utility to run a more cost effective mix of generation. This is because discharging the stored electricity during peak times may eliminate the need to dispatch additional expensive on-peak conventional generation.
Reduced Outages	Electricity storage can be used during a power outage as a backup power supply for one or more customers until normal electric service can be restored. The backup would only be available for a limited time (a few hours) depending on the amount of energy stored. However, even a temporary backup power supply can reduce the number of outages experienced by customers and/or greatly mitigate the impact of a disturbance event. Alternatively, storage can be used to provide grid support that will inherently increase the reliability of the system.
Improved Power Quality	ES can be used to protect on-site loads downstream from storage against short-term duration events affecting power quality. ES can also be located on the system and used to help regulate voltage thereby improving power quality for end-users. Manifestations of poor power quality include variations in voltage magnitude, variations in the primary 60-Hz frequency at which power is delivered, and interruptions in service ranging from a fraction of a second to several minutes.
Reduced CO_2, NO_x, SO_x, and Particulate Emissions	Electricity storage can reduce electricity peak demand and thereby reduce feeder losses. This translates into a reduction in emissions if peak generation is 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. Alternatively, by providing certain ancillary services, storage can enable conventional generation resources to be operated at more optimal conditions resulting in an emissions benefit. Finally, storage can yield a reduced emissions benefit by enabling greater utilization of renewable resources.

Appendix B: Benefit Calculations

B.1 Electric Energy Time Shift

G &T; Deregulated Market; Non-Utility Merchant

- Primary Benefit: Arbitrage Revenue (Non-Utility Merchant)
  - Calculation: Total Energy Discharged for Arbitrage (MWh) x [Avg. On-Peak Price of Electricity ($/MWh) – Avg. Off-Peak Price of Electricity ($/MWh) /Storage System Round-trip Efficiency (%)]
- Secondary Benefit: Reduced Emissions (Society)
  - Calculation: Total Energy Discharged for Arbitrage (MWh) x [Emissions Factor for Generation on the Margin (tons/MWh) – Emissions Factor for Base Generation (tons/MWh)/ Storage System Round-trip Efficiency (%)] x Value of Emissions ($/ton)
- Additional Benefit: Optimized Generator Operation (Non-Utility Merchant)
  - ES used for this application will be providing energy during peak times and may thereby allow enable conventional generators to operate closer to their optimal loading conditions thus improving overall generation system performance.
- Additional Benefit: Deferred Generation Capacity Investments (Non-Utility Merchant)
  - ES can effectively reduce peak energy load, reducing the need for further investments in generation capacity from merchant generators.
- Additional Benefit: Deferred Transmission Capacity Investments (Utility)
  - If the ES device that is shifting electricity from off-peak to peak is located downstream on a transmission system, it can defer the need to upgrade the transmission system to meet peak demand conditions.
- Additional Benefit: Reduced Electricity Losses (Utility)
  - If the ES that is time-shifting is located downstream on the transmission system then peak load on the transmission lines upstream will be reduced. Since losses are proportional to square of current, reducing peak load on lines will result in fewer losses overall.

G&T, Distribution; Regulated Market; Utility

- Primary Benefit: Reduced Electricity Costs (Utility/Ratepayer)
  - A utility that charges ES when demand is low, and discharges the devices when demand is high may decrease their energy costs by allowing the utility to run a more cost effective mix of generation. This can reduce a utilities overall cost of providing energy to its customers.
  - Calculation: Total Energy Discharged for Energy Time-Shift (MWh) x [Avg. Variable Peak Generation Cost ($/MWh) – Avg. Variable Off-Peak Generation Cost ($/MWh) /ES Efficiency (%)]
- Secondary Benefit*:* Reduced Emissions (Society)
  - Calculation: Total Energy Discharged for Energy Time-Shift (MWh) x [Emissions Factor for Generation on the Margin (tons/MWh) – Emissions Factor for Base Generation (tons/MWh)/ Storage System Round-trip Efficiency (%)] x Value of Emissions ($/ton)
- Additional Benefit: Optimized Generator Operation (Utility)
  - ES used for this application will be providing energy during peak times and may enable conventional generators to operate closer to their optimal loading conditions thus improving overall generation system performance and reducing variable operation costs.
- Additional Benefit: Deferred Generation Investment (Utility)

  - Using ES for this application can effectively reduce peak energy load, reducing the need for utility investments in generation capacity.
- Additional Benefit: Deferred Transmission Investment (Utility)
  - If the ES device that is shifting electricity from off-peak to peak is located downstream on a transmission system, it can defer the need to upgrade the transmission system to meet peak demand conditions.
- Additional Benefit: Deferred Distribution Investment (Utility)
  - If the ES device that is shifting electricity from off-peak to peak is located downstream on a distribution system, it can defer the need to upgrade the distribution system to meet peak demand conditions.
- Additional Benefit: Deferred Electricity Losses (Utility)
  - If the storage device that is time-shifting is located downstream on the transmission or distribution system then peak load on the transmission or distribution lines upstream will be reduced. Since losses are proportional to square of current, reducing peak load on lines will result in fewer losses overall.

B.2 Electric Supply Capacity

G &T, Distribution; Deregulated Market; Non-Utility Merchant

- Primary Benefit: Capacity Market Revenue (Non-Utility Merchant)
  - Calculation: Total ES Capacity sold [MW-h] x Avg. Capacity Market Value [$/MW-h]
  - Note: This calculation assumes an hourly market cycle for this service. In many wholesale electricity markets, generation capacity cost is not separated from energy costs. In these regions, capacity costs are embedded in the unit price of energy. In such cases, there is no way to generate an explicit revenue by selling generation capacity.

G&T, Distribution; Regulated Market; Utility

- Primary Benefit: Deferred Generation Capacity Investment (Utility/Ratepayer)
  - Calculation: [Generation Capacity Deferred (MW) x Capital Cost of Deferred Generation Capacity ($/MW) x Fixed Charge Rate] + [Yearly Fixed O&M Costs of Deferred Generation Capacity ($/MW-yr) x Generation Capacity Deferred (MW)]
  - Note: This yearly deferral amount only accrues between the initial and final year of generation deferral.

B.3 Load Following

G&T, Deregulated Market, Non-Utility Merchant

- Primary Benefit: Ancillary Service Revenue (Non-Utility Merchant)
  - Calculation: [Total Load Following Services Provided(MW-h) x Avg. Price for Load Following ($/MW-h)]
  - Note: This calculation assumes an hourly market cycle for this service. In many electricity markets, load following is not a separate ancillary service and is provided through the sub-hourly energy markets. In such cases, there is no way to generate explicit revenue by load following services.
- Additional Benefit: Reduced Emissions (Society)
  - Using ES to provide load following may result in an emissions benefit since generators that would have provided this service can now operate at more optimal conditions since they can avoid operating a partial load conditions. This can improve overall heat rate and result fewer emissions.

- Additional Benefit: Optimized Generator Operation (Non-Utility Merchant)
  - Using ES to provide load following may result in a system benefit since generators that would have provided this service can now operate at more optimal conditions since they can avoid operating a partial load conditions. This can improve overall heat rate resulting in more cost effective operation.
- Additional Benefit: Deferred Generation Capacity Investment
  - Using ES to provide this ancillary service frees up conventional generation to meet load and may therefore result in deferred generation capacity investment.

G&T, Regulated Market, Utility

- Primary Benefit: Optimized Generator Operation (Utility/Ratepayer)
  - Calculation: [Total Energy Discharged for Load Following (MWh) x (Marginal Operating Cost of Conventional Load Following Generation ($/MWh) – Marginal Operating Cost of Base Load Generation ($/MWh)/ Storage System Round-trip Efficiency (%)]
- Primary Benefit: Deferred Generation Capacity Investments (Utility/Ratepayer)
  - Calculation: [Total ES Capacity Installed (kW) x Capital Cost of Conventional Generation Capacity used for Load Following ($/kW) x Fixed Charge Rate]
- Additional Benefit: Reduced Emissions (Society)
  - Using ES to provide this ancillary service may result in a system benefit since generators that would have provided this service can now operate at more optimal conditions since they can avoid operating a partial load conditions. This can improve overall heat rate and result fewer emissions.

B.4 Area Regulation

G&T, Deregulated Market, Non-Utility Merchant

- Primary Benefit: Ancillary Service Revenue (Non-Utility Merchant)
  - Calculation: [Total Area Regulation Services Provided(MW-h) x Avg. Price for Area Regulation ($/MW-h)] + [(Total Energy Discharged for Area Regulation (MWh) – Total Charging Required for Area Regulation (MWh)) x Avg. Wholesale Price of Electricity ($/MWh)]
  - Note: This calculation assumes an hourly market cycle for this service.
- Additional Benefit: Reduced Emissions (Society)
  - Using ES to provide area regulation may result in an emissions benefit since generators that would have provided this service would be able to operate at more optimal conditions since they would avoid operating a partial load conditions. This would improve overall heat rate and result fewer emissions.
- Additional Benefit: Optimized Generator Operation (Non-Utility Merchant)
  - Storage can provide regulation services, reducing the need for regulation from generators. Regulation requires rapid generator ramping, reducing generation efficiency. Therefore, using ES to provide area regulation may result in a system benefit since generators that would have provided this service would be able to operate at more optimal conditions since they can avoid ramping and operating at partial load conditions. This can improve overall heat rate resulting in more cost effective operation.
- Additional Benefit: Deferred Generation Capacity Investments:
  - Using ES to provide this ancillary service frees up conventional generation to meet load and may therefore result in deferred generation capacity investment.

G&T, Regulated Market, Utility

- Primary Benefit: Deferred Generation Investment (Utility/Ratepayer) – Because ES can respond to system regulation needs more accurately and quickly than some conventional generation sources, less capacity could be required if ES devices rather than conventional devices were used to provide this service.
    - Calculation: [Conventional Capacity Required for same level of Area Regulation (MW) – ES Capacity for Area Regulation (MW)] x Price of Conventional Capacity ($/MW)
- Additional Benefit: Optimized Generator Operation (Utility)
    - Storage can provide regulation services, reducing the need for regulation from generators. Regulation requires rapid generator ramping, reducing generation efficiency. Therefore, using ES to provide area regulation may result in a system benefit since generators that would have provided this service would be able to operate at more optimal conditions since they can avoid ramping and operating at partial load conditions. This can improve overall heat rate resulting in more cost effective operation.
- Additional Benefit: Reduced Emissions (Society)
    - Using ES to provide area regulation may result in an emissions benefit since generators that would have provided this service can now operate at more optimal conditions since they can avoid operating a partial load conditions. This can improve overall heat rate and result fewer emissions.

B.5 Electric Supply Reserve Capacity

G&T, Deregulated Market, Non-Utility Merchant

- Primary Benefit: Ancillary Service Revenue (Non-Utility Merchant)
    - Calculation: [Total Spinning-Reserve Services Provided (MW-h) x Avg. Price for Spinning Reserve Services ($/MW-h)] + [Total Non-Spinning-Reserve Services Provided(MW-h) x Avg. Price for Non-Spinning Reserve Services ($/MW-h)] + [Total Backup Supply Services Provided(MW-h) x Avg. Price for Backup Supply Services ($/MW-h)]
- Secondary Benefit: Reduced Emissions (Society)
    - Using ES to provide spinning reserve service may result in a system benefit since generators that would have provided this service will no longer have to operate at partial load conditions. This will improve the heat rate of the generation unit and result fewer emissions.
    - Calculation: Total Spinning-Reserve Services Provided (MW-h) x [Emissions Factor of Conventional Generation at Partial Load (tons/MWh) – Emissions Factor of Conventional Generation at Optimal Load (tons/MWh)] x Value of Emissions ($/ton)
- Secondary Benefit: Optimized Generator Operation (Non-Utility Merchant)
    - Using ES to provide spinning reserve service may result in a system benefit since generators that would have provided this service will no longer have to operate at partial load conditions. This can improve overall heat rate resulting in more cost effective operation.
    - Calculation: Total Spinning-Reserve Services Provided (MW-h) x [Marginal Costs of Conventional Generation at Partial Load ($/MWh) – Marginal Costs of Conventional Generation at Optimal Load ($/MWh)]
- Additional Benefit: Deferred Generation Capacity Investments:
    - Using ES to provide this ancillary service frees up conventional generation to meet load and may therefore result in deferred generation capacity investment.

G&T, Regulated Market, Utility

- Primary Benefit: Optimized Generator Operation (Utility/Ratepayer)
    - Total Spinning-Reserve Services Provided (MW-h) x [Marginal Costs of Conventional Generation at Partial Load ($/MWh) – Marginal Costs of Conventional Generation at Optimal Load ($/MWh)]
- Secondary Benefit: Reduced Emissions (Society)
    - Total Spinning-Reserve Services Provided (MW-h) x [Emissions Factor of Conventional Generation at Partial Load (tons/MWh) – Emissions Factor of Conventional Generation at Optimal Load (tons/MWh)] x Value of Emissions ($/ton)
- Additional Benefit: Deferred Generation Capacity Investments (Utility)
    - Using ES to provide this ancillary service frees up conventional generation to meet load and may therefore result in deferred generation capacity investment.

B.6 Voltage Support

G&T; Deregulated Market, Regulated Market; Non-Utility Merchant or Utility -

- Primary Benefit: Ancillary Service Revenue (Non-Utility Merchant or Utility)
    - Annual Reactive Power Capacity Available for Voltage Support (MVAR) x Annual Capacity Payment for Voltage Support ($/MVAR-yr)

Distribution; Deregulated Market, Regulated Market; Utility

- Primary Benefit: Improved Power Quality (Utility)
    - Distributed ES can provide voltage support by rapidly injecting reactive power into the system. ES may be able to react to system needs for this service faster than conventional solutions such as capacitors and regulators. Providing voltage support in this way can result in improved power quality for end-users. From the utility's perspective, if there is a voltage problem on the system that is causing end user power quality issues which must be addressed, they can be addressed with either an ES solution or conventional solution. Therefore, the maximum monetary value that can be attributed to improving power quality with ES is equal to the minimum capital investment that would have been made to address the problem with a conventional solution. Because it is likely that an ES deployment used for this application would also be used for one or more applications, it may make sense to use ES to provide this service even if the ES solution is more expensive than the conventional solution.
    - Calculation: Capital Cost of Conventional Voltage Support Solution ($/kVA) x Nameplate Reactive Power Capacity of ES (kVA) x Fixed Charge Rate]
    - Note: This yearly deferral amount is assumed to accrue for the life of the ES deployment.

B.7 Transmission Support

G&T; Regulated, Deregulated; Utility

Within this application ES can be used to provide the following services:

- Transmission Stability Damping – Power system stability limitations are often characterized by low frequency oscillations (0.5 – 1 Hz) following a major system disturbance. Power transfers are often limited to prevent growing oscillations from occurring following loss of a single major transmission line or generator. When limited by long-term stability the transmission capacity can be increased by providing active damping of these oscillations. ES devices can actively dampen these system oscillations through modulation of both real and reactive power. Using ES to provide this service can defer the need to invest in additional transmission capacity.

- Under-frequency Load Shedding Reduction – When the power system suffers the loss of a major resource such as a generating plant or major importing transmission lines the system frequency will drop and continue to decline until the generating resource/load balance is restored. Because ES can inject real power rapidly into the system, it is an effective method to offset, or reduce, under frequency load shedding because it reduces the mismatch between load and supply capability that takes place because of the system disturbance. Therefore, using ES to provide this service can result in a reliability benefit.
- Primary Benefit: Deferred Transmission Investment (Utility/Ratepayer)
    - Calculation: Annual Transmission Enhancement Benefit ($/kW-year) x ES Capacity (kW)
    - Default Annual Transmission Enhancement Benefit ($/kW-year) = 15.1 $/kW-year
- Primary Benefit: Reduced Outages (Utility/Ratepayer)
    - Calculation: Number of Underfrequency Load-Shedding Occurrences (#) x Value of Avoided Load-Shedding Occurrence ($/kW) x ES Capacity (kW)
    - Default Value of Avoided Load-Shedding Occurrence ($/kW) = 12.8 $/kW

B.8 Reduced Transmission Congestion

G&T; Deregulated; Non-Utility Merchant

- Primary Benefit: Reduced Congestion Costs (Non-Utility Merchant)
    - Calculation: [Hours of Congestion Avoided (hr) x Congestion Charge ($/MW-h) x ES Capacity Installed (MW)] – [Hours of Congestion Avoided (hr) x ES Capacity (MW) x Avg. Wholesale Price of Electricity ($/MWh)/ES Efficiency (%) – Hours of Congestion Avoided (hr) x ES Capacity (MW) x Avg. Wholesale Price of Electricity ($/MWh)]

G&T; Regulated; Utility

- Primary Benefit: Reduced Congestion Costs (Utility/Ratepayer)
    - Transmission congestion may force a less cost effective dispatch of generation units (i.e. units with greater marginal operating costs may be forced to run due to congestion on the transmission system). ES located downstream of congestion can mitigate this cost.
    - Calculation: [Hours of Congestion Avoided (hr) x ES Capacity Installed (MW) x Average Variable Operating Cost of Congestion Generation ($/MWh)] – [Hours of Congestion Avoided (hr) x ES Capacity (MW) x Average Variable Operating Cost of Non-Congestion Generation ($/MWh)/ES Efficiency (%)]
- Secondary Benefit: Deferred Transmission Investment (Utility/Ratepayer)
    - Installing ES downstream of congestion could mitigate congestion and avoid or defer a transmission capacity upgrade.
    - Calculation: Transmission Capacity Deferred (kVA) x Capital Cost of Transmission Capacity ($/kVA) x Fixed Charge Rate] + Yearly O&M Costs of Transmission Distribution Capacity ($/yr)
    - Note: This yearly deferral amount only accrues between the initial and final year of transmission deferral.

B.9 Transmission and Distribution Upgrade Deferral

G&T; Deregulated, Regulated; Utility

- Primary Benefit: Deferred Transmission Investments (Utility/Ratepayers)

    - This yearly deferral amount only accrues between the initial and final year of transmission deferral.
    - [Transmission Capacity Deferred (kVA) x Capital Cost of Transmission Capacity ($/kVA) x Fixed Charge Rate] + Yearly O&M Costs of Transmission Distribution Capacity ($/yr)
- Additional Benefit: Optimized Generator Operation (Utility or Non-Utility Merchant)
    - ES used for this application will be providing energy during peak times and may enable conventional generators to operate closer to their optimal loading conditions thus improving overall generation system performance.
- Additional Benefit: Deferred Generation Capacity Investment
    - To defer a transmission or distribution upgrade using ES the unit is located downstream of strained assets and charged during off-peak times and discharged during peak times. This will effectively shift load away from the peak time of the system reducing the need for utility investments in generation capacity to meet peak load.
- Additional Benefit: Reduced Electricity Losses
    - To defer a transmission or distribution upgrade using ES the unit is located downstream of strained assets and charged during off-peak times and discharged during peak times. This will effectively reduce the peak load on the transmission and distribution system thereby reducing losses overall.
- Additional Benefit: Reduced Emissions
    - A storage device used for this application will be shifting peak electricity usage which may result in optimized generator operation and/or reduced electricity losses. Both of these benefits will result in the additional benefit of reducing emissions.

Distribution; Deregulated, Regulated; Utility

- Primary Benefit: Deferred Distribution Investments (Utility/Ratepayers)
    - This yearly deferral amount only accrues between the initial and final year of transmission deferral.
    - [Distribution Capacity Deferred (kVA) x Capital Cost of Deferred Distribution Capacity ($/kVA) x Fixed Charge Rate] + Yearly O&M Costs of Deferred Distribution Capacity ($/yr)
- Additional Benefit: Reduced Electricity Losses
    - To defer a transmission or distribution upgrade using ES the unit is located downstream of strained assets and charged during off-peak times and discharged during peak times. This will effectively reduce the peak load on the transmission and distribution system thereby reducing losses overall.
- Additional Benefit: Reduced Emissions
    - A storage device used for this application will be shifting peak electricity usage which may result in optimized generator operation and/or reduced electricity losses. Both of these benefits will result in the additional benefit of reducing emissions.
- Additional Benefit Optimized Generator Operation (Utility or Non-Utility Merchant)
    - ES used for this application will be providing energy during peak times and may enable conventional generators to operate closer to their optimal loading conditions thus improving overall generation system performance
- Additional Benefit: Deferred Generation Capacity Investments
    - To defer a transmission or distribution upgrade using ES the unit is located downstream of strained assets and charged during off-peak times and discharged during peak times. This will effectively shift load away from the peak time of the system reducing the need for utility investments in generation capacity to meet peak load.

B.10 Time-of-Use Energy Cost Management

End-Use; Regulated, Deregulated; End User

- Primary Benefit: Reduced Electricity Cost (Consumer)
  - Calculation: Total Energy Discharged for TOU Energy x [Avg. On-Peak Retail Price of Electricity ($/MWh) – Avg. Off-Peak Retail Price of Electricity ($/MWh) /Storage System Round-trip Efficiency (%)]
- Additional Benefit: Deferred Generation Capacity Investment (Utility or Non-Utility Merchant)
  - A deferred generation investment benefit may result if many end-users take advantage of the TOU Energy Cost Management application since the shifting of energy from peak to off-peak by multiple End Users may allow base-load and intermediate generation capacity to meet peak generation needs.
- Additional Benefit: Optimized Generator Operation (Utility or Non-Utility Merchant)
  - Storage used by many End Users for this application may effectively reduce peak energy usage and may enable conventional generators to operate closer to their optimal loading conditions thus improving overall generation system performance.
- Additional Benefit: Deferred Transmission Capacity Investment (Utility)
  - Storage used by many End Users for this application may effectively reduce on-peak energy usage, reducing the need for further utility investments in transmission capacity.
- Additional Benefit: Deferred Distribution Capacity Investment (Utility)
  - Storage used by many End Users for this application may effectively reduce on-peak energy usage, reducing the need for further utility investments in distribution capacity.
- Additional Benefit: Reduced Electricity Losses (Utility)
  - If many End Users use storage to reduce their effective peak energy usage, the peak load on the system will be reduced reducing fewer line losses overall.
- Additional Benefit: Reduced Emissions (Society)
  - If many end-users take advantage of the TOU Energy Cost Management application, peak energy usage on the system overall may be shifted. This shifting can result in lower electricity losses and/or optimized generator operation both of which will also lead to reduced emissions.

B.11 Demand Charge Management

End-Use; Regulated, Deregulated; End User

- Primary Benefit: Reduced Electricity Cost (Consumer)
  - Calculation: [Avg. Monthly Load Reduction from ES at Peak (kW) x Peak Demand Charge ($/kW-month)] + [Avg. Monthly Load Reduction from ES at Partial-Peak (kW) x Partial-Peak Demand Charge ($/kW-month)] + [Avg. Monthly Load Reduction from ES at Off-Peak (kW) x Off-Peak Demand Charge ($/kW-month)] x Number of Months that Demand Charges are Avoided (# months)
- Additional Benefit: Deferred Generation Capacity Investment
  - A deferred generation investment benefit may result if many end-users take advantage of the Demand Charge Management application since the shifting of energy from peak to off-peak by multiple End-Users may allow base-load and intermediate generation capacity to meet peak generation needs.
- Additional Benefit: Optimized Generator Operation (Utility or Non-Utility Merchant)
  - Storage used by many End Users for this application may effectively reduce peak energy usage and may enable conventional generators to operate closer to their optimal loading conditions thus improving overall generation system performance.

- Additional Benefit: Deferred Transmission Capacity Investment (Utility)
  - Storage used by many End Users for this application may effectively reduce on-peak energy usage, reducing the need for further utility investments in transmission capacity.
- Additional Benefit: Deferred Distribution Capacity Investment (Utility)
  - Storage used by many End Users for this application may effectively reduce on-peak energy usage, reducing the need for further utility investments in distribution capacity.
- Additional Benefit: Reduced Electricity Losses (Utility)
  - If many End Users use storage to reduce their effective peak energy usage, the peak load on the system will be reduced reducing fewer line losses overall.
- Additional Benefit: Reduced Emissions (Society)
  - If many end-users take advantage of the Demand Charge Management application, peak energy usage on the system overall may be shifted. This shifting can result in lower electricity losses and/or optimized generator operation both of which will also lead to reduced emissions.

B.12 Electric Service Reliability

G&T, Distribution; Regulated, Deregulated; Utility

- Primary Benefit: Reduced Outages (Utility/Ratepayer)
  - A utility may install ES near a customer site, or on a feeder, to bolster poor reliability or ensure highly reliable electric service. From the utility's perspective, this issue can either be addressed with either an ES solution or conventional solution. Since both solutions will provide the same reliability benefit the maximum monetary value that can be attributed to improving reliability with ES is equal to the minimum capital investment that would have been made to address the problem with a conventional solution. Because it is likely that an ES deployment used for this application would also be used for one or more applications, it may make sense to use ES to provide this service even if the ES solution is more expensive than the conventional solution.
  - Calculation: Capital Cost of Conventional Electric Service Reliability Solution ($/kW) x Total ES Capacity Installed (kW)-x Fixed Charge Rate]
  - Note: This yearly deferral amount only accrues between the initial and final year of transmission deferral.

End-Use; Regulated, Deregulated; End-User

- Primary Benefit: Reduced Outages (Consumer)
  - Calculation: Σ{ Outage Minutes Avoided by Customer Class (min) x Average Hourly Load Not Served During Outage per Customer by class (kW) x VOS by Customer Class ($/kWh)}

B.13 Electric Service Power Quality

End-Use; Regulated, Deregulated; End-User

- Primary Benefit: Improved Power Quality (Consumer)
  - Typical Number of Power Quality Events per Year x Value of Power Quality Event ($/kW peak load) x Minimum(Customer Peak Load (kW), Nameplate Capacity of ES Device)
  - Default Typical Number of Power Quality Events per Year = 10
  - Default Value of Power Quality Event ($/kW peak load) = 5

B.14 Renewable Energy Time-Shift

G&T, Distribution; Deregulated Market; Non-Utility Merchant

- Primary Benefit: Arbitrage Revenue (Non-Utility Merchant)
  - Calculation: Total Renewable Energy Discharged for Arbitrage (MWh) x [Avg. On-Peak Price of Electricity ($/MWh) – Avg. Off-Peak Price of Electricity ($/MWh) /Storage System Round-trip Efficiency (%)]
- Secondary Benefit: Reduced Emissions (Society)
  - Calculation: Total Renewable Energy Discharged for Arbitrage (MWh) x Emissions Factor for Generation on the Margin (tons/MWh) x Value of Emissions ($/ton)
- Additional Benefit: Optimized Generator Operation (Non-Utility Merchant)
  - ES used for Renewables Energy Time-shift will be providing energy during peak times and may thereby obviate the need to ramp up generators and/or run less efficient peaking units. This could have the overall effect of allowing generation to be run at its optimal loading conditions thus improving overall generation system performance and reducing variable operations costs. Furthermore, since the energy provided by the ES would have come from renewable sources variable operations cost would be decreased to an even greater degree.
- Additional Benefit: Deferred Generation Capacity Investments (Non-Utility Merchant)
  - Storage can effectively reduce peak energy load, reducing the need for further investments in generation capacity from merchant generators.
- Additional Benefit: Deferred Transmission Capacity Investments (Utility)
  - If the ES device that is shifting electricity from off-peak to peak is located downstream on a transmission system, it can defer the need to upgrade the transmission system to meet peak demand conditions.
- Additional Benefit: Deferred Distribution Capacity Investments (Utility)
  - If the ES device that is shifting electricity from off-peak to peak is located downstream on a distribution system, it can defer the need to upgrade the distribution system to meet peak demand conditions.
- Additional Benefit: Reduced Electricity Losses (Utility)
  - If the storage device that is time-shifting is located downstream on the transmission system then peak loading on the transmission lines upstream will be reduced. Since losses are proportional to square of current, reducing peak load on lines will result in fewer losses overall.

End-Use; Regulated, Deregulated Market; End-User –

- Primary Benefit: Reduced Electricity Costs (Consumer)
  - If an end-user owns renewable generation, and their electric service tariff includes TOU energy prices, then the end user could use storage to time-shift energy to reduce their cost for electricity. The calculation assumes that the user only uses energy that would have been otherwise spilled to charge the battery.
  - Calculation: Total Energy Discharged for Renewable Energy Time-Shift (MWh) x Avg. On-Peak Price of Electricity ($/MWh)
- Secondary Benefit: Reduced Emissions (Society)
  - Calculation: Total Energy Discharged for Renewable Energy Time-Shift (MWh) x Emissions Factor for Generation on the Margin (tons/MWh) x Value of Emissions ($/ton)

G&T, Distribution; Regulated Market; Utility

- Primary Benefit: Reduced Electricity Costs (Utility/Ratepayer)
  - A utility that charges ES with renewable energy when demand is low, and discharges the devices when demand is high, may decrease their energy costs by offsetting the need to operate conventional peaking units that have higher variable operation costs compared to renewables. This will have the effect of reducing a utilities overall cost to provide energy to its customers.
  - Calculation: Total Energy Discharged for Renewable Energy Time-Shift (MWh) x [Avg. Variable Peak Generation Cost ($/MWh) – Variable Renewable Generation Cost ($/MWh) /ES Efficiency (%)]
- Secondary Benefit: Reduced Emissions (Society)
  - Calculation: Total Energy Discharged for Renewable Energy Time-Shift (MWh) x [Emissions Factor for Generation on the Margin (tons/MWh) x Value of Emissions ($/ton)
- Additional Benefit: Optimized Generator Operation (Utility)
  - ES used for Renewables Energy Time-shift will be providing energy during peak times and may thereby obviate the need to ramp up generators, startup generators, and/or run less efficient peaking units. This could have the overall effect of allowing generation to be run at its optimal loading conditions thus improving overall generation system performance and reducing variable operations costs.
- Additional Benefit: Deferred Generation Capacity Investment (Utility)
  - Using ES for this application can effectively reduce peak energy load, reducing the need for utility investments in generation capacity.
- Additional Benefit: Deferred Transmission Capacity Investments (Utility)
  - If the ES device that is shifting electricity from off-peak to peak is located downstream on a transmission system, it can defer the need to upgrade the transmission system to meet peak demand conditions.
- Additional Benefit: Deferred Distribution Capacity Investment (Utility)
  - If the ES device that is shifting electricity from off-peak to peak is located downstream on a distribution system, it can defer the need to upgrade the distribution system to meet peak demand conditions.
- Additional Benefit: Reduced Electricity Losses (Utility)
  - If the storage device that is time-shifting is located downstream on the transmission or distribution system then peak loading on the lines upstream will be reduced. Since losses are proportional to square of current, reducing peak load on lines will result in fewer losses overall.

B.15 Renewables Capacity Firming

G&T, Deregulated Market, Non-Utility Merchant

- Primary Benefit: Capacity Market Revenue (Non-Utility Merchant)
  - Calculation: [Effective Load Carrying Capacity (ELCC) of Renewable Post-Firming (%) – ELCC of Renewable Pre-Firming (%)] x Nameplate Capacity of Renewable Resource (MW) x Hours of Renewable Energy Capacity Sold (hr) x Average Value of Capacity on the Market [$/MW-h]
  - Note: This calculation assumes an hourly market cycle for this service. In many wholesale electricity markets, generation capacity cost is not separated from energy costs. In these regions, capacity costs are embedded in the unit price of energy. In such cases, there is no way to generate an explicit revenue by selling generation capacity.

- Secondary Benefits: Reduced Emissions (Society) – The electricity provided by the ES is coming from renewable sources and therefore offsets otherwise polluting conventional capacity.
    - Calculation: [Effective Load Carrying Capacity (ELCC) of Renewable Post-Firming (%) – ELCC of Renewable Pre-Firming (%)] x Nameplate Capacity of Renewable Resource (MW) x Capacity Factor of Renewable Resource (%) x 8760 hours x Emissions Factor for Base Generation (tons/MWh) x Value of Emissions ($/ton)

G&T, Regulated Market, Utility

- Primary Benefit: Deferred Generation Capacity Investment (Utility/Ratepayer)
    - Calculation: [Effective Load Carrying Capacity (ELCC) of Renewable Post-Firming(%) – ELCC of Renewable Pre-Firming (%)] x Nameplate Capacity of Renewable Resource (MW) x Price of Conventional Capacity ($/MW)
    - Price of Conventional Capacity – This represents a proxy for avoided new central generation as a result of firming renewable resources. Assuming the marginal generation would be a conventional natural gas combined cycle plant with a base overnight cost of $978 per kW and a fixed O&M cost of $14/kW with an annual fixed charge rate of 11% for a utility or 15% for a non-utility, results in an Annual Cost of Generation Capacity of $121,000 per MW and $161,000 per MW respectively.
- Secondary Benefits: Reduced Emissions (Society)
    - The capacity provided by the ES is coming from renewable sources and therefore offsets otherwise polluting conventional capacity.
    - Calculation: [Effective Load Carrying Capacity (ELCC) of Renewable Post-Firming (%) – ELCC of Renewable Pre-Firming (%)] x Nameplate Capacity of Renewable Resource (MW) x Capacity Factor of Renewable Resource (%) x 8760 hours x Emissions Factor for Base Generation(tons/MWh) x Value of Emissions ($/ton)

B.16.1 Wind Generation Grid Integration (Short-Term)

G&T, Deregulated Market, Non-Utility Merchant

- Primary Benefit: Capacity Market Revenue (Non-Utility Merchant)
    - Calculation: [Effective Load Carrying Capacity (ELCC) of Renewable Post-Firming (%) – ELCC of Renewable Pre-Firming (%)] x Nameplate Capacity of Renewable Resource (MW) x Hours of Renewable Energy Capacity Sold (hr) x Average Value of Capacity on the Market [$/MW-h]
    - Note: This calculation assumes an hourly market cycle for this service. In many wholesale electricity markets, generation capacity cost is not separated from energy costs. In these regions, capacity costs are embedded in the unit price of energy. In such cases, there is no way to generate an explicit revenue by selling generation capacity.
- Secondary Benefits: Reduced Emissions (Society) – The electricity provided by the ES is coming from renewable sources and therefore offsets otherwise polluting conventional capacity.
    - Calculation: [Effective Load Carrying Capacity (ELCC) of Renewable Post-Firming (%) – ELCC of Renewable Pre-Firming (%)] x Nameplate Capacity of Renewable Resource (MW) x Capacity Factor of Renewable Resource (%) x 8760 hours x Emissions Factor for Base Generation (tons/MWh) x Value of Emissions ($/ton)

G&T, Regulated Market, Utility

- Primary Benefit: Deferred Generation Capacity Investment (Utility/Ratepayer)

- Calculation: [Effective Load Carrying Capacity (ELCC) of Renewable Post-Firming(%) – ELCC of Renewable Pre-Firming (%)] x Nameplate Capacity of Renewable Resource (MW) x Price of Conventional Capacity ($/MW)
- Price of Conventional Capacity – This represents a proxy for avoided new central generation as a result of firming renewable resources. Assuming the marginal generation would be a conventional natural gas combined cycle plant with a base overnight cost of $978 per kW and a fixed O&M cost of $14/kW with an annual fixed charge rate of 11% for a utility or 15% for a non-utility, results in an Annual Cost of Generation Capacity of $121,000 per MW and $161,000 per MW respectively.

- Secondary Benefits: Reduced Emissions (Society)
  - The capacity provided by the ES is coming from renewable sources and therefore offsets otherwise polluting conventional capacity.
  - Calculation: [Effective Load Carrying Capacity (ELCC) of Renewable Post-Firming (%) – ELCC of Renewable Pre-Firming (%)] x Nameplate Capacity of Renewable Resource (MW) x Capacity Factor of Renewable Resource (%) x 8760 hours x Emissions Factor for Base Generation(tons/MWh) x Value of Emissions ($/ton)

B.16.2 Wind Generation Grid Integration (Long-Term)

G&T, Distribution; Deregulated Market; Non-Utility Merchant

- Primary Benefit: Arbitrage Revenue (Non-Utility Merchant)
  - Calculation: Total Renewable Energy Discharged for Arbitrage (MWh) x [Avg. On-Peak Price of Electricity ($/MWh) – Avg. Off-Peak Price of Electricity ($/MWh) /Storage System Round-trip Efficiency (%)]
- Secondary Benefit: Reduced Emissions (Society)
  - Calculation: Total Renewable Energy Discharged for Arbitrage (MWh) x Emissions Factor for Generation on the Margin (tons/MWh) x Value of Emissions ($/ton)
- Additional Benefit: Optimized Generator Operation (Non-Utility Merchant)
  - Optimized Generator Operation (Non-Utility Merchant) – ES used for Renewables Energy Time-shift will be providing energy during peak times and may thereby obviate the need to ramp up generators and/or run less efficient peaking units. This could have the overall effect of allowing generation to be run at its optimal loading conditions thus improving overall generation system performance and reducing variable operations costs. Furthermore, since the energy provided by the ES would have come from renewable sources variable operations cost would be decreased to an even greater degree.
- Additional Benefit: Deferred Generation Capacity Investments (Non-Utility Merchant)
  - Storage can effectively reduce peak energy load, reducing the need for further investments in generation capacity from merchant generators.
- Additional Benefit: Deferred Transmission Capacity Investments (Utility)
  - If the ES device that is shifting electricity from off-peak to peak is located downstream on a transmission system, it can defer the need to upgrade the transmission system to meet peak demand conditions.
- Additional Benefit: Deferred Distribution Capacity Investments (Utility)
  - If the ES device that is shifting electricity from off-peak to peak is located downstream on a distribution system, it can defer the need to upgrade the distribution system to meet peak demand conditions.
- Additional Benefit: Reduced Electricity Losses (Utility)

- If the storage device that is time-shifting is located downstream on the transmission system then peak loading on the transmission lines upstream will be reduced. Since losses are proportional to square of current, reducing peak load on lines will result in fewer losses overall.

G&T, Distribution; Regulated Market; Utility

- Primary Benefit: Reduced Electricity Costs (Utility/Ratepayer)
    - A utility that charges ES with renewable energy when demand is low, and discharges the devices when demand is high, may decrease their energy costs by offsetting the need to operate conventional peaking units that have higher variable operation costs compared to renewables. Furthermore, this application may enable the utility to operate the generation units at more optimal levels thereby further reducing variable operation costs. Taken together these two mechanisms can reduce a utilities overall cost of providing energy to its customers.
    - Calculation: Total Energy Discharged for Renewable Energy Time-Shift (MWh) x [Avg. Variable Peak Generation Cost ($/MWh) – Variable Renewable Generation Cost ($/MWh) /ES Efficiency (%)]
- Secondary Benefit: Reduced Emissions (Society)
    - Calculation: Total Energy Discharged for Renewable Energy Time-Shift (MWh) x [Emissions Factor for Generation on the Margin (tons/MWh) x Value of Emissions ($/ton)
- Additional Benefit: Optimized Generator Operation (Utility)
    - ES used for Renewables Energy Time-shift will be providing energy during peak times and may thereby obviate the need to ramp up generators and/or run less efficient peaking units. This could have the overall effect of allowing generation to be run at its optimal loading conditions thus improving overall generation system performance and reducing variable operations costs. Furthermore, since the energy provided by the ES would have come from renewable sources variable operations cost would be decreased to an even greater degree.
- Additional Benefit: Deferred Generation Capacity Investment (Utility)
    - Using ES for this application can effectively reduce peak energy load, reducing the need for utility investments in generation capacity.
- Additional Benefit: Deferred Transmission Capacity Investments (Utility)
    - If the ES device that is shifting electricity from off-peak to peak is located downstream on a transmission system, it can defer the need to upgrade the transmission system to meet peak demand conditions.
- Additional Benefit: Deferred Distribution Capacity Investment (Utility)
    - If the ES device that is shifting electricity from off-peak to peak is located downstream on a distribution system, it can defer the need to upgrade the distribution system to meet peak demand conditions.
- Additional Benefit: Reduced Electricity Losses (Utility)
    - If the storage device that is time-shifting is located downstream on the transmission or distribution system then peak loading on the lines upstream will be reduced. Since losses are proportional to square of current, reducing peak load on lines will result in fewer losses overall.

Appendix C: Additional Benefit Calculations

By default, the ESCT does not quantify additional benefits in the main part of the main part of the tool. Instead, the user has the option to work through various worksheets in the Computational Module in order to quantify these types of benefits. These benefits are not quantified by default for one or more of the following reasons:

1) The equations to calculate these benefits would require inputs that are very difficult measure.
2) These benefits typically accrue to stakeholders that are not the actual owners of the ES assets.
3) The monetary value associated with these benefits may be very small when only considering a single deployment as opposed to considering a system-wide deployment of ES.
4) The benefits only arise under specific circumstances.
5) The calculations utilize estimated inputs as opposed to measured data to monetize the benefits.

If after reading the explanation of the additional benefit, the user wishes to calculate the value of the benefit, they can click a link which will open a worksheet that will collect the additional inputs required to monetize these benefits. This section of the User Guide documents the equations used to monetize the additional benefits. The rationales that explain how various storage applications can yield each benefit are contained in Appendix B: Benefit Calculations.

The Lifecycle Value Multiplier is a value used to estimate the present worth of a stream of annual expenses or revenues. It is a function of a specific combination of investment duration (project life), financial escalation rate (e.g., inflation), and an annual discount rate. The simplified approach described below for estimating the Lifecycle Value Multiplier of a stream of annual expenses or revenues is used for each additional benefit. It is intended to provide a simple, auditable, and flexible way to estimate the present worth of a benefit. Implicit in this approach is the assumption that annual benefits for all years considered are the same as the first year, except that the cost or price escalates at some percentage each year.

e = Annual price escalation rate (%/year) – The annual average rate at which the price of goods and services increases during a specific time period.
d = discount rate (%/year) – The interest rate used to discount future cash flows to account for the time value of money.
i = year

C.1 Optimized Generator Operation (Utility/Ratepayer)

Using ES to respond to changes in load by absorbing or discharging energy as needed by the system can enable generators to run closer to their optimum operating conditions. Therefore, by smoothing the load curve that the generation fleet must meet, ES can improve generation performance as measured by improved heat rate efficiency and startup costs and lead to lower overall operating costs. The benefit calculated in this worksheet accrues to the utility directly or is ultimately passed down to the ratepayer in the form of lower electricity costs.

Applications that can lead to this benefit include:

- Electric Energy Time-shift
- Area Regulation
- Transmission & Distribution (T&D) Upgrade Deferral
- Time-of-use (TOU) Energy Cost Management
- Demand Charge Management
- Renewables Energy Time-shift
- Wind Generation Grid Integration - Long Duration

The General Calculation

This calculation assumes that a generic system benefit results from the improved heat rate and reduced startup costs of an entire fleet of generation units. By providing energy time-shifting, ancillary services, or peak-shedding services, ES systems enable the conventional generation fleet as a whole to operate closer to the optimum conditions. This benefit calculation assumes that the change in generation operation cannot be traced back to a particular plant. Therefore, the value of this benefit is captured by the monetization parameter called "Improved System Performance" which represents the incremental monetary value that each MWh of relevant ES discharge yields. The main assumption of this calculation is that each MWh of ES discharged that provides energy time-shifting, ancillary services, or peak-shedding, results in the general improvement of conventional generation fleet operation.

- Lifetime Value ($) = Total Energy Discharged Annually to Provide Service Related to the Application (MWh) × Improved System Performance Multiplier ($/MWh) × Lifecycle Value Multiplier

The default value for the Improved System Performance Multiplier was derived by assuming:

- Plant efficiency of 42% at optimal conditions
- Plant efficiency of 39% during ramping up/down
- Optimum variable operation costs of 50 $/MWh
- Variable operation costs (VOC) of 53.9 $/MWh during ramping up/down (42% ÷ 39% × 50 $/MWh)
- Assume each hour of service corresponds with two-thirds of the time ramping up/down and one-third of the time running at near optimal efficiency leading to an average VOC of 52.6 $/MWh.
- The difference between the optimal VOC and the sub-optimal VOC is 2.6 $/MWh, this is the Improved System Performance Multiplier value.

The Specific Calculation

This calculation assumes that benefits result from the improved heat rate and reduced startup costs of a specific generation unit. By providing energy time-shifting, ancillary services, or peak-shedding services, ES systems enable a particular generation unit to operate closer to the optimum conditions. The main assumption of this calculation is that the user has knowledge about how the operation of a particular plant has improved as a result of the ES deployment. The other main assumption of these calculations is that all energy discharged to perform a relevant application results in an optimized generator operation benefit for a particular plant. This calculation does not take into consideration the variable operations cost of the plant that charged the battery, because the financial cost of charging the battery has already been taken into account in the primary and secondary equations associated with each application. It is acknowledged that it is difficult to estimate what system heat rates are with and without ES. Accurate estimations will likely require the running of dispatch models and/or detailed analysis of how plant heat rates are correlated with loading and ramping conditions.

- Lifetime Value ($) = [Percent Decrease in Plant Efficiency (%) × Optimum Variable Operations Costs ($/MWh) × Total Energy Discharged Annually to Provide Service Related to the Application (MWh) + Number of Avoided Startups per Year (#) × Startup Costs ($/#)] × Lifecycle Value Multiplier

This calculation assumes that increases in operation costs are proportional to the plant efficiency such that if plant efficiency is reduced by 1% operations costs will be increased by the same percentage.

C.2 Optimized Generator Operation (Non-Utility Merchant)

Using ES to respond to changes in load by absorbing or discharging energy as needed by the system can enable generators to run closer to their optimum operating conditions. Therefore, by smoothing the load curve that the generation fleet must meet, ES can improve generation performance as measured by improved heat rate efficiency and startup costs and lead to lower overall operating costs. The benefit calculated in this worksheet ultimately accrues to the ratepayer in the form of lower electricity costs since the cost effectiveness of the entire system is optimized. The non-utility merchant that is pursuing the application which results in this additional benefit does not accrue any generation operational benefit since it is assumed that they will operate their generation and ES assets in a way that maximizes their profits according to the market. That is, they may choose to run their generation assets at suboptimal conditions if the value for that service, as determined by the market, adequately reimburses them for the additional operational costs. Therefore, only a general calculation is offered in this worksheet for calculating this benefit. Similarly, if an end-user is in a deregulated market and is pursuing an application that results in this benefit it is assumed that the cost effectiveness of the entire generation system is optimized and the benefit will ultimately flow to the entire population of ratepayers.

Applications that can lead to this benefit include:

- Electric Energy Time-shift
- Load Following
- Area Regulation
- Time-of-use (TOU) Energy Cost Management
- Demand Charge Management
- Renewables Energy Time-shift
- Wind Generation Grid Integration - Long Duration

The General Calculation

This calculation assumes that a generic system benefit results from the improved heat rate and reduced startup costs of an entire fleet of generation units. By providing energy time-shifting, ancillary services, or peak-shedding services, ES systems enable the conventional generation fleet as a whole to operate closer to the optimum conditions. This benefit calculation assumes that the change in generation operation cannot be traced back to a particular plant. Therefore, the value of this benefit is captured by the monetization parameter called "Improved System Performance" which represents the incremental monetary value that each MWh of relevant ES discharge yields. The main assumption of this calculation is that each MWh of ES discharge that provides energy time-shifting, ancillary services, or peak-shedding, results in the general improvement of conventional generation fleet operation. This benefit, which is derived from improvement in heat rate, should only be calculated if it isn’t already captured in price signals used in the primary and secondary benefit calculations.

- Lifetime Value ($) = Total Energy Discharged Annually to Provide Service Related to the Application (MWh) × Improved System Performance Multiplier ($/MWh) × Lifecycle Value Multiplier

C.3 Deferred Generation Capacity Investment

By shifting peak demand or providing ancillary services that are typically provided by conventional generation assets, ES can result in deferred generation capacity investment benefits. By shifting peak demand, less generation capacity will be required to meet the system needs and by providing ancillary services more generation capacity will be freed up to meet system energy needs. In both a regulated and deregulated market the need for investment in generation capacity by the utility or non-utility merchant is reduced, which ultimately results in lower system and electricity costs overall. Therefore, in each instance the benefit ultimately accrues to the utility/ratepayer group.

Applications that can lead to this benefit include:

- Electric Energy Time-shift
- Load Following
- Area Regulation
- Electric Supply Reserve Capacity
- Transmission & Distribution (T&D) Upgrade Deferral
- Time-of-use (TOU) Energy Cost Management
- Demand Charge Management
- Renewables Energy Time-shift
- Wind Generation Grid Integration - Long Duration

The Incremental Calculation

This calculation assumes that one can monetize an incremental amount of generation deferral by using the unit cost of capacity as a proxy for deferral value. Using this methodology allows a value for generation deferral to be calculated even if an actual generation plant will not necessarily be deferred. This is a useful calculation if the impact of an ES application is small or if the user does not have visibility into whether a generation unit will actually be deferred or not (e.g. a non-utility merchant in a deregulated market may not have this kind of insight). This equation assumes that deferral begins in the first year that peak demand is reduced or ancillary services are provided.

- Lifetime Value ($) = Overnight Capital Cost of Fuel on the Margin ($/kW) × 1,000 kw/MW × Fixed Charge Rate (%) ÷ 8,760 hours/year × Peak Reduction (MW) × Number of Hours of Peak Reduction × Lifecycle Value Multiplier
- Lifetime Value ($) = Overnight Capital Cost of Fuel on the Margin ($/kW) × 1,000 kw/MW × Fixed Charge Rate (%) ÷ 8,760 hours/year × Total Ancillary Services Provided (MW-h) × Lifecycle Value Multiplier

The Specific Calculation

This calculation assumes that a small investment in ES capacity caused enough peak demand shifting or freed up enough peak generation capacity so that the construction of a generation plant can be deferred for a year or more. This calculation assumes that a user has enough visibility into the system peak load and generation mix to make a determination as to whether generation capacity will be deferred or not. It is likely that only a utility in a regulated market could take advantage of the calculation below.

- Lifetime Value ($) = Overnight Capital Cost of Fuel on the Margin ($/kW) × 1,000 kw/MW × Generation Capacity Deferred × Fixed Charge Rate (%) × Lifecycle Value Multiplier

- The Lifecycle Value Multiplier is a function of the initial and final year of deferral.

C.4 Deferred Transmission Investment

By shifting peak demand, ES can result in deferred transmission capacity investment benefits. In both a regulated and deregulated market the need for investment in transmission capacity by the utility will be reduced if ES on transmission systems operate in such a way that reduces peak. This ultimately results in lower system and electricity costs overall. Therefore, in each instance the benefit ultimately accrues to the utility/ratepayer group.

Applications that can lead to this benefit include:

- Electric Energy Time-shift
- Time-of-use (TOU) Energy Cost Management
- Demand Charge Management
- Renewables Energy Time-shift
- Wind Generation Grid Integration - Long Duration

The Incremental Calculation

This calculation assumes that one can monetize an incremental amount of transmission deferral by using the unit cost of capacity as a proxy for deferral value. Using this methodology allows a value for transmission deferral to be calculated even if an actual transmission line will not necessarily be deferred. This is a useful calculation if the impact of an ES application is small or if the user does not have visibility into whether a transmission line will be deferred or not (e.g. a non-utility merchant in a deregulated market may not have this kind of insight). This equation assumes that deferral begins in the first year that peak demand is reduced.

- Lifetime Value ($) = Incremental Cost of Transmission Upgrade/Capacity ($/MW-mile) × Miles Downstream ES is Located × Fixed Charge Rate (%) ÷ 8,760 hours/year × Peak Reduction (MW) × Number of Hours of Peak Reduction × Lifecycle Value Multiplier

The Specific Calculation

This calculation assumes that a small investment in ES capacity caused enough peak demand shifting that the construction or upgrading of a transmission line can be deferred for a year or more. This calculation assumes that a user has enough visibility into the system peak load and transmission capacity needs to make a determination as to whether generation capacity will be deferred or not. It is likely that only a utility could take advantage of the calculation below, therefore only a user who selected "Utility" as the owner in the Asset Characterization Module is able to calculate a non-zero value using the calculation below. Furthermore, if using an energy storage device to defer a T&D investment proper consideration must be given to reliability. T&D capital investments must maintain the extremely high reliability of the electric delivery system. Therefore, any energy storage solution that defers the need for a T&D investment must similarly maintain the reliability of the system. For energy storage deployments this means ensuring that the storage solution has enough redundancy or modularity such that the effective reliability of the solution is adequate. The Lifecycle Value Multiplier is a function of the initial and final year of deferral.

- Lifetime Value ($) = Capital Cost of Deferred Transmission Capacity ($/mile) × Miles of Transmission Capacity Being Deferred (miles) × Fixed Charge Rate (%) × Lifecycle Value Multiplier

C.5 Deferred Distribution Investment

By shifting peak demand ES can result in deferred distribution capacity investment benefits. In both a regulated and deregulated market the need for investment in distribution capacity by the utility will be reduced if ES systems located downstream on distribution systems operate in such a way that reduces peak. This ultimately results in lower system and electricity costs overall. Therefore, in each instance the benefit ultimately accrues to the utility/ratepayer group.

Applications that can lead to this benefit include:

- Electric Energy Time-shift
- Time-of-use (TOU) Energy Cost Management
- Demand Charge Management
- Renewables Energy Time-shift
- Wind Generation Grid Integration - Long Duration

The Incremental Calculation

This calculation assumes that one can monetize an incremental amount of distribution deferral by using the unit cost of capacity as a proxy for deferral value. Using this methodology allows a value for distribution deferral to be calculated even if an actual distribution circuit will not necessarily be deferred. This is a useful calculation if the impact of an ES application is small or if the user does not have visibility into whether a distribution circuit or asset will be deferred or not (e.g. a non-utility merchant in a deregulated market may not have this kind of insight). This equation assumes that deferral begins in the first year that peak demand is reduced.

- Lifetime Value ($) = Typical Distribution Delivery Cost ($/kWh) × 1,000 kW/MW × Peak Reduction (MW) × Number of Hours of Peak Reduction × Lifecycle Value Multiplier

The Specific Calculation

This calculation assumes that a small investment in energy storage capacity caused enough peak demand shifting that the construction or upgrading of a distribution circuit or asset can be deferred for a year or more. This calculation assumes that a user has enough visibility into the system peak load and distribution capacity needs to make a determination as to whether generation capacity will be deferred or not. It is likely that only a utility would have the insight necessary to take advantage of the calculation below, therefore only a user who selected "Utility" as the owner in the Asset Characterization Module is able to calculate a non-zero value using the calculation below. Furthermore, if using an energy storage device to defer a T&D investment proper consideration must be given to reliability. T&D capital investments must maintain the extremely high reliability of the electric delivery system. Therefore, any energy storage solution that defers the need for a T&D investment must similarly maintain the reliability of the system. For energy storage deployments this means ensuring that the storage solution has enough redundancy or modularity such that the effective reliability of the solution is adequate. The Lifecycle Value Multiplier is a function of the initial and final year of deferral.

- Lifetime Value ($) = Marginal Cost of Deferred Distribution Capacity ($/kW) × 1,000 kW/MW × Upgrade Factor (#) × Fixed Charge Rate (%) × Lifecycle Value Multiplier

C.6 Reduced Electricity Losses

If the storage device that is shifting electricity usage to off-peak periods is located downstream on the distribution system (assuming a radial network) then peak load on the distribution circuits upstream will be reduced. Since losses are proportional to the square of current, reducing peak load on circuits will result in fewer losses overall. If the peak-shifting energy storage device reduce peak demand on the transmission system, the incremental demand losses and energy losses may be reduced. In both of these cases the actions of the utility, non-utility and end-user energy storage owners will create an effect that impacts the utility T&D system and therefore benefits will accrue to the utility/ratepayer group.

Applications that can lead to this benefit include:

- Electric Energy Time-shift
- Transmission & Distribution (T&D) Upgrade Deferral
- Time-of-use (TOU) Energy Cost Management
- Demand Charge Management
- Renewables Energy Time-shift
- Wind Generation Grid Integration - Long Duration

It is assumed that the user has a general idea about the system in which electric losses will be reduced. Specifically, it is assumed that the user has general knowledge about the voltage, loading, resistance, and length of the system that is affected by their peak-shifting activities. Many of these quantities can be estimated and default values are provided in the tool. However, the average and on-peak load of the transmission and/or distribution system before and after energy storage is a key input about which the user must develop some reasonable estimate. The length of the distribution system that is impacted by the storage deployment is another key input about which the user must develop a reasonable estimate. The utility owner of storage may be able to determine more accurate estimates for the inputs, but the non-utility owners of storage should be able determine reasonably accurate estimates of all the inputs as well. The end-user energy storage owner will have a more difficult time estimating some of the inputs below and should limit their analysis to the distribution system.

This calculation considers two aspects of reduced losses: 1) the reduced demand losses and 2) the reduced energy losses. The reduced demand losses are monetized by estimating the annualized cost of the saved power capacity. The reduced energy losses are monetized by considering the average variable costs of generating electricity. The benefits calculated in the equations below help reduce the overall system costs of providing electricity to end-users. Even though many of these savings might seem to accrue to T&D utilities, ultimately they should be passed on to ratepayers via the rate case process. Therefore, in this tool this benefit accrues to the utility/ratepayer stakeholder group.

The Distribution Calculation

The equations below are used to calculate the demand and energy loss savings on the distribution system as a result of using energy storage for peak-demand shifting type applications. The loss savings calculated by these equations are relative to the status of the system before energy storage was deployed, as opposed to being relative to alternative T&D solutions. The inputs that relate to peak-load refer to the hourly peak-load on the distribution feeder or feeders that are impacted by the energy storage solution. These calculations assume that the distribution system impacted by the energy storage solution is radial in design. If this is not true then the peak demand loss saving calculations below are not valid. Calculations to analyze network systems are not included in this worksheets because these types of distribution systems are not common and it is not clear if energy storage devices will be installed on these systems in the near term due system stability concerns. Finally, these calculations assume that the energy storage solution is operated in such a way that reduces peak demand for a significant number of hours throughout the year (500-1,000 hours). If this is not true then the energy loss savings calculations below are not valid.

- Lifetime Value ($) = [Annual Demand Loss Savings ($) + Annual Energy Loss Saving ($)] × Lifecycle Value Multiplier
  - Annual Demand Loss Savings ($) = (On-Peak Distribution Demand Losses Pre-ES (kW) – On-Peak Distribution Demand Losses Post-ES (kW)) × Price of Conventional Capacity ($/kW)
    - On-Peak Demand Losses = [Peak Load/(Voltage × √3)]^2 × System Resistance (Ohms/Mile) × Miles of System Impacted[6]
  - Annual Energy Loss Savings ($) = [Energy Losses Pre-Energy Storage (MWh) – Energy Losses Post-Energy Storage (MWh)] × Average Variable Generation Costs ($/MWh)
    - Energy Losses (MWh) = Peak Demand Losses (MW) × Load Loss Factor × 8760 hours/year
    - Load Loss Factor = C_1 × Load Factor + C_2 × (Load Factor)^2
      - Load Factor = Average Load (MW)/Peak Load (MW)

The Transmission Equation

The equations below are used to calculate the demand and energy loss savings on the transmission system as a result of using energy storage for peak-demand shifting type applications. The loss savings calculated with these equations are relative to the status of the system before energy storage was deployed, as opposed to being relative to alternative T&D solutions. The inputs that relate to peak-load refer to the hourly peak-load on the transmission system impacted by the energy storage solution. These calculations assume that the transmission system impacted by the energy storage solution is a networked design. As a result, the calculation methodology for peak-demand losses requires the user to enter the incremental system losses as a percentage of peak load. This value can be estimated from load flow studies, but if these types of studies are not available the, default values can be used. These calculations also assume that the system is a three-phase AC current system. Finally, these calculations assume that the energy storage solution is operated in such a way that reduces peak demand for a significant number of hours throughout the year (500-1,000 hours). If this is not true then the energy loss savings calculations are not valid.

- Lifetime Value ($) = [Annual Demand Loss Savings ($) + Annual Energy Loss Saving ($)] × Lifecycle Value Multiplier
  - Annual Demand Loss Savings ($) = (On-Peak Transmission Demand Losses Pre-ES (kW) – On-Peak Transmission Demand Losses Post-ES (kW)) × Price of Conventional Capacity ($/kW)
    - On-Peak Transmission Demand Losses (kW) = Peak Transmission Load (kW) × Incremental Peak System Losses (%)
  - Annual Energy Loss Savings ($) = Peak Transmission Demand Loss Savings (MW) × Load Loss Factor × 8760 hours/year
    - Load Loss Factor = C_1 × Load Factor + C_2 × (Load Factor)^2
      - Load Factor = Average Load (MW)/Peak Load (MW)

C.7 Reduced Emissions

ES can reduce system losses by reducing system peak demand. This translates into a reduction in emissions if peak load losses are reduced by a significant degree compared to the slight increase in off-

[6] The radical-3 term only applies if the distribution system is three-phase.

peak losses and/or if peak generation units have lower or similar emissions factors to baseload units. Alternatively, by providing certain ancillary services, ES can enable conventional generation resources to be operated at more optimal conditions resulting in an emissions benefit.

Applications that can lead to this benefit include:

- Load Following
- Area Regulation
- Transmission & Distribution (T&D) Upgrade Deferral
- Time-of-use (TOU) Energy Cost Management
- Demand Charge Management

The calculation for this benefit assumes that there is a market for emissions and therefore a monetary value can be assigned to them. Furthermore, the calculations used to monetize the reduced emissions that result from reduced systems losses assume that the additional benefit Reduced Electricity Losses has been calculated or that off-peak and on-peak electricity loss savings from ES are known.

- Lifetime Value ($) = [Annual Value of Reduced CO_2 Emissions ($) + Annual Value of Reduced SO_x Emissions ($) + Annual Value of Reduced NO_x Emissions ($)] × Lifecycle Value Multiplier
  - Annual Value of Reduced Emission ($) = Reduced Emissions (tons) × Value of Emission ($/ton)
    - Reduced Emissions (tons) = Emissions from Conventional Generation Providing Ancillary Service (tons) - Emissions from Energy Storage Providing Ancillary Service (tons)
      - Emissions from Energy Storage Providing Ancillary Service (tons) = [Total Energy Discharged for Providing Service (MWh) × Regional Emissions Factor (lb/MWh) × Round Trip Efficiency (%)÷ 2,000 lb/ton
      - Emissions from Conventional Generation Providing Ancillary Service (tons) = Total hours of Service Provided (hr) × Operating Capacity of Conventional Generation (MW) × Emissions Factor for Conventional Generation (lb/MWh) × Percent Decrease in Plant Efficiency (%) ÷ 2,000 lb/ton
      - Note: The Operating Capacity of Conventional Generation is assumed to be 400MW.
    - Reduced Emissions (tons) = Energy Loss Savings (MWh) × Regional Average Emission Factor (lb/MWh) ÷ 2,000 lb/ton

Appendix D: Detailed Explanations of Inputs and Escalation

This appendix presents detailed explanations inputs for the ESCT and escalation techniques. Understanding these concepts is critical to the effective use of the tool.

The ESCT provides generic default escalation factors, but the user also has the opportunity to enter their own values as well. Table 10 and

Table 11 provide estimated average load growth factors and inflation factors, by region, which users may use as standard set of escalation factor values to enter into the ESCT.

If less than five years of data are entered into the tool, the escalation factors and techniques are used on the last year of entered data to calculate a full data set that can be used to calculate benefits into the future. Benefits can be calculated for up to 40 years past the initial project installation date. However, the user sets the parameter that determines when benefits decline to zero. After the first year in which benefits are zero, all benefits are automatically set to zero for the remaining years.

The ESCT requires the user to enter one to five years of project data. With these inputs, the ESCT can calculate benefits beyond the first five years by escalating values using various methods and factors. The two escalation factors used are inflation, for financial parameters, and electric demand growth, for load and congestion-related parameters. Table 12 shows which escalation factors are used to escalate the various inputs. If an input is not represented in Table 12, then the input is held constant after the fifth year.

Table 13 summarizes all of the inputs required to calculate every benefit in the ESCT. 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 10. Default Load Growth Escalation Factors by Region

NERC Region	*Default Escalation Factor Value*[7]
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%

[7] 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 11. Default Inflation Rates by Region

NERC Region	*Default Escalation Factor Value*[8]
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 12. Inputs and related escalation factors

Escalation Factor	*Inputs that are projected by escalation factor*
Load Growth	Total ES Capacity Sold Total Load Following Services Provided Total Energy Discharged for Load Following Total Area Regulation Services Provided ES Capacity for Area Regulation Conventional Capacity Required for Equivalent Level of Area Regulation Total Spinning-Reserve Services Provided Total Non-Spinning-Reserve Services Provided Total Backup Supply Services Provided Total Hours of Congestion Avoided Total Energy Discharged for TOU Energy-Cost Management Average Monthly Load Reduction from ES at Peak Average Monthly Load Reduction from ES at Partial-Peak Average Monthly Load Reduction from ES at Off-Peak Average Hourly Residential Load Not Served During Outage Average Hourly Commercial Load Not Served During Outage Average Hourly Industrial Load Not Served During Outage Customer Peak Load

[8] Source: US Bureau of Labor and Statistics CPI Database, All Urban Consumers (Current Series) (Consumer Price Index - CPI), All Items, Base Period = 1982-1984=100, Average CAGR 2000 – 2010. NPCC = Northeast urban area; WECC = West urban area; TRE = Houston-Galveston-Brazoria; TX, SPP = Kansas City, MO-KS; SERC = South urban area; FRCC = Miami-Fort Lauderdale, FL; ASCC = Anchorage, AK; HI = Honolulu, HI; RFC and MRO = Midwest urban area. http://data.bls.gov/pdq/querytool.jsp?survey=cu

Escalation Factor	*Inputs that are projected by escalation factor*
Inflation	Average On-Peak Price of Electricity Average Off-Peak Price of Electricity Average Variable Peak Generation Costs Average Variable Off-Peak Generation Costs Value of CO2 Value of SOx Value of NOx Value of PM Average Value of Capacity on the Market Average Price for Load Following Capital Cost of Conventional Generation Capacity used for Load Following Marginal Operating Cost of Load Following Generation Marginal Operating Cost of Base Load Generation Average Price for Area Regulation Price of Conventional Capacity Average Price for Spinning Reserve Services Average Price for Non-Spinning Reserve Services Average Price for Backup Supply Services Marginal Operating Costs of Conventional Generation at Partial Load Marginal Operating Costs of Conventional Generation at Optimal Load Annual Capacity Payment for Voltage Support Composite Value of Service Annual Transmission Enhancement Benefit Value of Avoided Load-Shedding Occurrences Average Congestion Charge Average Wholesale Price of Electricity Average Variable Operating Cost of Congestion Generation Average On-Peak Retail Price of Electricity Average Off-Peak Retail Price of Electricity Peak Demand Charge Partial-Peak Demand Charge Off-Peak Demand Charge Residential VOS Commercial VOS Industrial VOS Value of Avoided Power Quality Events Average Variable Renewable Generation Costs Capital Cost of Conventional Voltage Support Solution Capital Cost of Conventional Electric Service Reliability Solution

Table 13. Input Summary Table

Metric	Units	Definition
Total Energy Discharged for Arbitrage	MWh	The total amount of energy discharged from the ES device and used for arbitrage purposes over a year.
Average On-Peak Price of Electricity	\$/MWh	The average on-peak price of wholesale electricity over a year.
Average Off-Peak Price of Electricity	\$/MWh	The average off-peak price of wholesale electricity over a year.
Total Energy Discharged for Energy Time-Shift	MWh	The total amount of energy discharged from the ES device for the purposes of shifting energy from an off-peak time to an on-peak time. Do this may allow a utility to decrease their costs by offsetting the need to run less efficient, more expensive peaking units.
Average Variable Peak Generation Costs	\$/MWh	The average variable generation costs for marginal generation units used to meet peak demand.
Average Variable Off-Peak Generation Costs	\$/MWh	The average variable generation costs for base load generation units.
CO2 Emissions Factor for Generation on the Margin	ton/MWh	The characteristic or average CO2 emissions factor for marginal generation units used to meet peak demand.
CO2 Emissions Factor for Base Generation	ton/MWh	The characteristic or average CO2 emissions factor for base load generation units.
SOx Emissions Factor for Generation on the Margin	ton/MWh	The characteristic or average SOx emissions factor for marginal generation units used to meet peak demand.
SOx Emissions Factor for Base Generation	ton/MWh	The characteristic or average SOx emissions factor for base load generation units.
NOx Emissions Factor for Generation on the Margin	ton/MWh	The characteristic or average NOx emissions factor for marginal generation units used to meet peak demand.
NOx Emissions Factor for Base Generation	ton/MWh	The characteristic or average NOx emissions factor for base load generation units.
PM Emissions Factor for Generation on the Margin	ton/MWh	The characteristic or average PM emissions factor for marginal generation units used to meet peak demand.
PM Emissions Factor for Base Generation	ton/MWh	The characteristic or average PM emissions factor for base load generation units.
Value of CO2	\$/ton	The anticipated or current market price of carbon 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.

Metric	Units	Definition
Value of PM	$/ton	The anticipated or current market price of PM emissions.
Total ES Capacity Sold	MW-h	The total ES capacity sold into an hourly capacity market over the course of a year.
Average Value of Capacity on the Market	$/MW-h	The average market price for capacity in the hourly capacity market.
Generation Capacity Deferred	MW	The size of the generation investment deferred as a result of installing ES.
Capital Cost of Deferred Generation Capacity	$/MW	The base overnight capital cost of the deferred generation investment.
Yearly O&M Costs of Deferred Generation Capacity	$/MW-year	The expected fixed yearly operations and maintenance costs of the deferred generation investment.
Annual Fixed Charge Rate for Generation Capital Investment	%	The rate used to convert capital plant installed cost into an annuity equivalent (payment) representing annual carrying charges for capital equipment. It includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes, and property taxes.
Initial Year of Generation Deferral	year	The first year that generation is deferred. Enter the value in 20XX format.
Final year of Generation Deferral	year	The last year that generation is deferred. Enter the value in 20XX format.
Total Load Following Services Provided	MW-h	The total ES capacity sold into an hourly market for load following services. The calculation that uses this input assumes there is an hourly capacity market for this service. However, in many markets load following is not a separate ancillary service and is provided through the sub-hourly energy markets. In such cases, there is no way to generate explicit revenue by providing load following services.
Average Price for Load Following	$/MW-h	The average market price paid for load following services in the hourly market.
Capital Cost of Conventional Generation Capacity used for Load Following	$/kW	The base overnight capital cost of the conventional generation typically used to provide load following services.
Total Energy Discharged for Load Following	MWh	The total energy discharged by ES for the purposes of load following.
Marginal Operating Cost of Load Following Generation	$/MWh	The typical marginal operating costs of conventional generation if it was being used to provide load following. If the generator is being run at sub-optimal load conditions the marginal operating costs may be higher than normal.
Marginal Operating Cost of Base Load Generation	$/MWh	The typical marginal operating costs of conventional base load generation. It is assumed that this is the type of generation that will be used to charge the ES that is providing load following services.

Metric	*Units*	*Definition*
Total Area Regulation Services Provided	MW-h	The total ES capacity sold into an hourly market for area regulation services.
Average Price for Area Regulation	$/MW-h	The average market price paid for area regulation services in the hourly market. If the market has a price for up regulation and down regulation please add the average cost of each and enter the sum into the tool.
ES Capacity for Area Regulation	MW	The amount of ES capacity being used to provide area regulation services.
Conventional Capacity Required for Equivalent Level of Area Regulation	MW	Because ES can respond to system regulation needs more accurately and quickly than some conventional generation sources, less capacity could be required if ES devices rather than conventional devices were used to provide this service. This input captures the amount of conventional capacity that would need to be devoted to area regulation in order to achieve the same level of service as the ES device.
Price of Conventional Capacity	$/MW	The annual price of conventional generation capacity. This can be estimated by assuming a base overnight cost of new generation and multiplying this cost by an annual fixed charge rate.
Total Spinning-Reserve Services Provided	MW-h	The total ES capacity sold into an hourly market for spinning-reserve services.
Average Price for Spinning Reserve Services	$/MW-h	The average market price paid for spinning-reserve services in the hourly market.
Total Non-Spinning-Reserve Services Provided	MW-h	The total ES capacity sold into an hourly market for non-spinning-reserve services.
Average Price for Non-Spinning Reserve Services	$/MW-h	The average market price paid for non-spinning-reserve services in the hourly market.
Total Backup Supply Services Provided	MW-h	The total ES capacity sold into an hourly market for backup supply services.
Average Price for Backup Supply Services	$/MW-h	The average market price paid for backup supply services in the hourly market.
Marginal Operating Costs of Conventional Generation at Partial Load	$/MWh	The typical marginal operating costs of conventional generation if it was being used to provide spinning-reserve capacity services. If a generator is being used to provide these services it is being run at partial load conditions; therefore, the marginal operating costs may be higher than normal.
Marginal Operating Costs of Conventional Generation at Optimal Load	$/MWh	The typical marginal operating costs of conventional generation at optimal loading conditions.
CO2 Emissions Factor of Generation at Partial Load	ton/MWh	The typical emissions factor of conventional generation operated at partial load so that it can provide spinning-reserve services.

Metric	Units	Definition
CO2 Emissions Factor of Generation at Optimal Load	ton/MWh	The typical emissions factor of conventional generation operated at optimal load.
SOx Emissions Factor of Generation at Partial Load	ton/MWh	The typical emissions factor of conventional generation operated at partial load so that it can provide spinning-reserve services.
SOx Emissions Factor of Generation at Optimal Load	ton/MWh	The typical emissions factor of conventional generation operated at optimal load.
NOx Emissions Factor of Generation at Partial Load	ton/MWh	The typical emissions factor of conventional generation operated at partial load so that it can provide spinning-reserve services.
NOx Emissions Factor of Generation at Optimal Load	ton/MWh	The typical emissions factor of conventional generation operated at optimal load.
PM Emissions Factor of Generation at Partial Load	ton/MWh	The typical emissions factor of conventional generation operated at partial load so that it can provide spinning-reserve services.
PM Emissions Factor of Generation at Optimal Load	ton/MWh	The typical emissions factor of conventional generation operated at optimal load.
Annual Reactive Power Capacity Available for Voltage Support	MVAR-yr	The annual ES capacity available for providing voltage support.
Annual Capacity Payment for Voltage Support	$/MVAR-yr	The approximate annual payment to generators for providing voltage support. These services are often procured through longer term, negotiated agreements.
Composite Value of Service	$/kWh	The composite value for avoiding an outage of 1 kW for one hour. This value should include both the value of avoided outages to the utility as well as the customers.
Annual Transmission Enhancement Benefit	$/kW-yr	When limited by long-term stability the transmission capacity can be increased by providing active damping of low frequency oscillations. ES devices can actively dampen these system oscillations through modulation of both real and reactive power. Using ES to provide this service can defer the need to invest in additional transmission capacity. This input estimates the value of this incremental transmission capacity increase.

Metric	Units	Definition
Number of Underfrequency Load-Shedding Occurrences	#	Because ES can inject real power rapidly into the system, it is an effective method to offset, or reduce, under frequency load shedding because it reduces the mismatch between load and supply capability that takes place because of the system disturbance. Therefore, using ES to provide this service can result in a reliability benefit. This input represents the number of underfrequency load shedding occurrences that were avoided as a result of using ES for this purpose.
Value of Avoided Load-Shedding Occurrences	$/#	This parameter represents the average value of each underfrequency load shedding occurrence that is avoided as a result of the ES device.
Total Hours of Congestion Avoided	hr	The total number of hours of congestion that the ES device was able to curtail.
Average Congestion Charge	$/MW-h	The average charge associated with the congestion that the ES device was able to curtail.
Average Wholesale Price of Electricity	$/MWh	The average wholesale price of electricity. For utilities that own and use their own generation this represents the average levelized cost of electricity from generation plants.
Average Variable Operating Cost of Congestion Generation	$/MWh	If a utility is using ES to avoid "congestion", it means they are using ES to address transmission constraints and enable the most cost effective generation dispatch. If ES were not used in this way this parameter captures the variable operating cost of the sub-optimal generation dispatch subject to the transmission constraints that ES alleviates.
Transmission Capacity Deferred	kVA	The size of the transmission investment deferred as a result of installing ES.
Annual Fixed Charge Rate for Transmission Capital Investment	%	The base overnight capital cost of the deferred transmission investment.
Capital Cost of Deferred Transmission Capacity	$/kVA	The expected fixed yearly operations and maintenance costs of the deferred transmission investment.
Yearly O&M Costs of Deferred Transmission Capacity	$/year	The equivalent (payment) representing annual carrying charges for capital equipment. It includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes, and property taxes.
Initial Year of Transmission Deferral	year	The first year that transmission is deferred. Enter the value in 20XX format.
Final year of Transmission Deferral	year	The last year that transmission is deferred. Enter the value in 20XX format.

Metric	Units	Definition
Distribution Capacity Deferred	kVA	The size of the distribution investment deferred as a result of installing ES. Please only enter a single value per deferral in the initial year of deferral. If there is no deferral in a given year, leave that entry cell blank.
Annual Fixed Charge Rate for Distribution Capital Investment	%	The rate used to convert capital distribution installed cost into an annuity equivalent (payment) representing annual carrying charges for capital equipment. It includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes, and property taxes. Please only enter a single value per deferral in the initial year of deferral. If there is no deferral in a given year, leave that entry cell blank.
Capital Cost of Deferred Distribution Capacity	$/kVA	The base overnight capital cost of the deferred transmission investment.
Yearly O&M Costs of Deferred Distribution Capacity	$/year	The expected fixed yearly operations and maintenance costs of the deferred transmission investment.
Initial Year of Distribution Deferral	year	The first year that transmission is deferred. Enter the value in 20XX format.
Final year of Distribution Deferral	year	The last year that transmission is deferred. Enter the value in 20XX format.
Total Energy Discharged for TOU Energy-Cost Management	MWh	Total amount of energy discharged by the ES device to provide energy during peak-time so as to avoid paying peak prices.
Average On-Peak Retail Price of Electricity	$/MWh	Average on-peak retail price of electricity. This would be the price that was avoided as a result of the ES device.
Average Off-Peak Retail Price of Electricity	$/MWh	Average off-peak retail price of electricity. This would be the price that was paid for electricity used to charge the ES device.
Average Monthly Load Reduction from ES at Peak	MW	For customers with a peak demand charge, this parameter represents the average monthly peak reduction that results from using the ES device to peak-shave during peak times.
Average Monthly Load Reduction from ES at Partial-Peak	MW	For customers with a partial-peak demand charge, this parameter represents the average monthly peak reduction that results from using the ES device to peak-shave during partial-peak times.
Average Monthly Load Reduction from ES at Off-Peak	MW	For customers with an off-peak demand charge, this parameter represents the average monthly peak reduction that results from using the ES device to peak-shave during off-peak times.

Metric	*Units*	*Definition*
Peak Demand Charge	$/MW-month	For customers with a peak demand charge, this parameter represents the price of that demand charge.
Partial-Peak Demand Charge	$/MW-month	For customers with a partial-peak demand charge, this parameter represents the price of that demand charge.
Off-Peak Demand Charge	$/MW-month	For customers with an off-peak demand charge, this parameter represents the price of that demand charge.
Outage Minutes Avoided by Residential Customers	minutes	The total outage minutes avoided by residential customers as a result of ES devices being used to provide power during system interruptions.
Outage Minutes Avoided by Commercial Customers	minutes	The total outage minutes avoided by commercial customers as a result of ES devices being used to provide power during system interruptions.
Outage Minutes Avoided by Industrial Customers	minutes	The total outage minutes avoided by industrial customers as a result of ES devices being used to provide power during system interruptions.
Average Hourly Residential Load Not Served During Outage	kW	The average residential load unserved during outages. This parameter can be estimated by determining the average load of customers whose reliability will be impacted by the ES device.
Average Hourly Commercial Load Not Served During Outage	kW	The average commercial load unserved during outages. This parameter can be estimated by determining the average load of customers whose reliability will be impacted by the ES device.
Average Hourly Industrial Load Not Served During Outage	kW	The average industrial load unserved during outages. This parameter can be estimated by determining the average load of customers whose reliability will be impacted by the ES device.
Residential VOS	$/kWh	Represents the true value of the electricity service to the residential 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.

Metric	Units	Definition
Commercial VOS	$/kWh	Represents the true value of the electricity service to the commercial 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 commercial customer or by a firm's expected net revenues associated with the added reliability.
Industrial VOS	$/kWh	Represents the true value of the electricity service to the commercial 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 commercial customer or by a firm's expected net revenues associated with the added reliability.
Utility VOS	$/MWh	Represents the true value of the electricity service to the utility without regard to the actual cost of providing the service. This input captures the value of service reliability quantified by taking into account the lost revenue of the utility from unserved energy as well as any regulatory fines or legal costs that could result from extended outages.
Typical Number of Power Quality Events per Year	#	The typical number of power quality events experienced each year such as variations in voltage magnitude, variations in frequency, or momentary service interruption. These power quality interruptions may disrupt operations, harm equipment, and result in lost revenue. It is assumed that the ES solution will avoid all power quality events that would have otherwise taken place.
Value of Avoided Power Quality Events	$/kW peak load	The value of avoiding each power quality event. This parameter may be quantified by taking into account the extent to which power quality events disrupt operations, harm equipment, and result in lost revenue or productivity.
Customer Peak Load	kW	The average monthly peak load.
Average Variable Renewable Generation Costs	$/MW	The average variable generation costs for renewable generation units used to charge ES devices and accomplish renewable energy time-shifting.
Total Renewable Energy Discharged for Arbitrage	MWh	The total amount of renewable energy discharged from the ES device and used for arbitrage purposes over a year.

Metric	*Units*	*Definition*
Total Renewable Energy Discharged for Energy Time-Shift	MWh	The total amount of renewable energy discharged from the ES device for the purposes of shifting energy from an off-peak time to an on-peak time. This may allow an end user to avoid paying peak-prices for electricity or this may allow a utility to decrease their costs by offsetting the need to run less efficient, more expensive peaking units.
Effective Load Carrying Capacity of Renewable Post-Firming	%	The effective load carrying capacity is a measure of a power plant's contribution to the greater electric supply system's capacity during times when the amount and reliability of capacity is important. The ELCC of renewable or intermittent sources is usually less than 100%. Firming a renewable resource with ES can increase that ELCC. This parameter captures the ELCC post-firming.
Effective Load Carrying Capacity of Renewable Pre-Firming	%	The effective load carrying capacity is a measure of a power plant's contribution to the greater electric supply system's capacity during times when the amount and reliability of capacity is important. The ELCC of renewable or intermittent sources is usually less than 100%. Firming a renewable resource with ES can increase that ELCC. This parameter captures the ELCC pre-firming.
Hours of Renewable Energy Capacity Sold	hr	The total hours of renewable energy capacity sold into an hourly capacity market over the course of a year. This input assumes that capacity was firmed with ES and the seller therefore was able to sell more capacity into the market than they otherwise would have been able to.
Nameplate Capacity of Renewable Resource	MW	The nameplate capacity of the renewable resource(s) that were firmed with ES.
Capacity Factor of Renewable Resource	%	The total number of hours the firmed renewable resource runs represented as a percentage of total hours in the year.
Capital Cost of Conventional Voltage Support Solution	$/kVAR	The amount of money that would be required to fix a reactive power issue that is causing power quality issues using a conventional solution. This value will be used as a proxy to monetize the power quality benefit provided by the ES solution.
Nameplate Reactive Power Capacity of ES	kVAR	The total reactive power output capacity of the distributed ES solution. This reactive power output capability of distributed ES devices would be used in the voltage support application to provide reactive power and manage voltage thereby ensuring better power quality and reliability.

Metric	Units	Definition
Annual Fixed Charge Rate for Voltage Support Capital Investment	%	The rate used to convert the capital cost of an installed conventional voltage support solution into an annuity equivalent (payment) representing annual carrying charges for capital equipment. It includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes, and property taxes.
Capital Cost of Conventional Electric Service Reliability Solution	$/kW	The amount of money that would be required to fix a reliability using a conventional solution. This value will be used as a proxy to monetize the reliability benefit provided by the ES solution.
Annual Fixed Charge Rate for Electric Service Reliability Capital Investment	%	The rate used to convert the capital cost of an installed conventional reliability solution into an annuity equivalent (payment) representing annual carrying charges for capital equipment. It includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes, and property taxes.

D.1 Default Values for Inputs

If the user does not have measured data to enter into the tool, they can leverage default values for most of the inputs. However, if default values are used the user should take care in interpreting the results since the default values tend to be general estimates, and the actual values for the user's project may vary greatly. Furthermore, default values do not take into account situations in which energy storage deployments are being used for multiple applications, rather they assume the storage is being used for a single application for an entire year. Therefore, if multiple applications are being pursued and default values are being used, the user must ensure that the default amount of energy discharge for each application is realistic considering that the storage is being used for more than one application throughout the year.

The table in this section explains how all of the default values in the tool are calculated and also lists the sources used to estimate these default values.

Table 14. Default Input Values for the ESCT

Metric	Source	Value/Equation
Total Energy Discharged for Arbitrage	Sandia Report SAND2010-0815, pg. 74. Assumes full storage power capacity is used for this application.	900 hours × ES Power Capacity
Average On-Peak Price of Electricity	Sandia Report SAND2010-0815, pg. 74	100 $/MWh

Metric	Source	Value/Equation
Average Off-Peak Price of Electricity	Sandia Report SAND2010-0815, pg. 74	50 $/MWh
Total Energy Discharged for Energy Time-Shift	Sandia Report SAND2010-0815, pg. 74. Assumes full storage power capacity is used for this application.	900 hours × ES Power Capacity
Average Variable Peak Generation Costs	EIA AEO 2011, DOE/EIA-0383(2010), Variable O&M for Conventional Combined Cycle Natural Gas Plant	45.6 $/MWh
Average Variable Off-Peak Generation Costs	EIA AEO 2011, DOE/EIA-0383(2010), Variable O&M for Conventional Coal Plant	24.3 $/MWh
CO2 Emissions Factor for Generation on the Margin	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas	1280 lbs/MWh
CO2 Emissions Factor for Base Generation	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Western Coal	2000 lbs/MWh
SOx Emissions Factor for Generation on the Margin	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas	0.006 lbs/MWh
SOx Emissions Factor for Base Generation	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Western Coal	3.5 lbs/MWh
NOx Emissions Factor for Generation on the Margin	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas	1.1 lbs/MWh
NOx Emissions Factor for Base Generation	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Western Coal	5.8 lbs/MWh
PM Emissions Factor for Generation on the Margin	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas	0.04 lbs/MWh
PM Emissions Factor for Base Generation	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Western Coal	0.2 lbs/MWh

Metric	Source	Value/Equation
Value of CO2	(1) $20/ton http://www.ctv.ca/servlet/ArticleNews/story/CTVNews/20070422/green_qp_070422/20070422?hub=TopStories (2) Calculated: avg YOY/2000 E3_Avoided Costs (Existing Intl Markets, OR Climate Trust, Utility Planning Docs, Models) p.90; 5% growth rt 2024 p.92 (3) The value of CO2 emissions is based on ICF Consulting projections in the "Very High Emissions" scenario and that an unlimited number of offsets are available for $6.50/ton, effectively providing a backstop to the CO2 allowance price. "RPS Sensitivity & Very High Emissions Reference & Package Cases - 10/26/05," ICF Consulting. Regional Greenhouse Gas Initiative, October 2005. Available at: http://www.rggi.org/docs/rps_hi_emis_10_26_05.ppt	20 $/ton
Value of SOx	(1) Evolution Markets - estimated 2010 bid price http://www.evomarkets.com/ (2) E3_Avoided Costs (South Coast Air Quality Management District-SCAQMD, RECLAIM data) p.88, 10% growth rt 2024 p.92 (2) Evolution Markets: the value of NOx emissions is its commodity value in the EPA SIP NOx Trading Program. For November 2005 the average monthly price was about $2,500 per ton. For 2007, 2008, Annual 2009 the average monthly prices were $608.81, $561.43, $5,005 http://www.evomarkets.com/	520 $/ton

Metric	Source	Value/Equation
Value of NOx	(1) Evolution Markets - estimated 2007-09 bid price http://www.evomarkets.com/ The value of SOx emissions is its commodity value in the cap and trade market for the EPA's Acid Rain Program. Each allowance permits a unit to emit one ton of SO2 during or after a specified year (2) For November 2005 average monthly price was $1,300/ton, increase w/ inflation http://www.evomarkets.com/	3,000 $/ton
Value of PM	Calculated: avg YOY E3_Avoided Costs (CA Air Resources Board-CARB) p.89; 10% growth rt 2024 p.92	36,000 $/ton
Total Energy Storage Capacity Sold	Sandia Report SAND2010-0815, pg. 77. Assumes full storage power capacity is used for this application.	2000 hours × ES Power Capacity
Average Value of Capacity on the Market	Updated Capital Cost Estimates for Electricity Generation Plants, EIA, November 2010, Table 1. Updated Estimates of Power Plant Capital and Operating Cost, Conventional NGCC Overnight Capital Cost (2010 $/kW) + Fixed O&M Cost (2010$/kW) assuming 15% fixed charge rate for non-utility and 11% fixed charge rate for utilities divided by 8760 hours per year.	(978 $/kW × Annual Fixed Charge Rate + 14 $/kW) × 1000 kW/MWh ÷ 8760 hours/year
Generation Capacity Deferred	Assumes a 40MW Gas fired peaking plant was avoided (e.g. GE Frame 6B (6581B))	40 MW
Capital Cost of Deferred Generation Capacity	COST ESTIMATES FOR THERMAL PEAKING PLANT, Parsons Brinckerhoff New Zealand Ltd, June 2008, http://large.stanford.edu/publications/coal/references/docs/thermal-eaking.pdf, Assumes a 40MW Gas fired peaking plant was avoided (e.g. GE Frame 6B (6581B))	1227 $/kW × 1000 kW/MW
Yearly O&M Costs of Deferred Generation Capacity	http://large.stanford.edu/publications/coal/references/docs/thermal-eaking.pdf, Assumes a 40MW Gas fired peaking plant was avoided (e.g. GE Frame 6B (6581B))	14 $/kW × 1000kW/MW

Metric	*Source*	*Value/Equation*
Annual Fixed Charge Rate for Generation Capital Investment	Same fixed charge rate used to amortize the cost of the energy storage deployment.	User Input
Initial Year of Generation Deferral	Same year as initial year of energy storage deployment.	User Input
Final year of Generation Deferral	Assume a 3 year deferral	User Input + 3 years
Total Load Following Services Provided	Sandia Report SAND2010-0815, pg. 78. Assumes 500 hours a year of service and full storage power capacity utilization.	500 hours × ES Power Capacity
Average Price for Load Following	Sandia Report SAND2010-0815, pg. 78	35 $/MW-h
Capital Cost of Conventional Generation Capacity used for Load Following	Updated Capital Cost Estimates for Electricity Generation Plants, EIA, November 2010, Table 1. Updated Estimates of Power Plant Capital and Operating Cost, Conventional NGCC Overnight Capital Cost (2010 $/kW) + Fixed O&M Cost (2010$/kW)	978 $/kW + 14 $/kw
Total Energy Discharged for Load Following	Sandia Report SAND2010-0815, pg. 78. Assumes 500 hours a year of service and full storage power capacity utilization.	500 hours × ES Power Capacity
Marginal Operating Cost of Load Following Generation	EIA AEO 2011, DOE/EIA-0383(2010), Variable O&M for Conventional Combined Cycle Natural Gas Plant	45.6 $/MWh
Marginal Operating Cost of Base Load Generation	EIA AEO 2011, DOE/EIA-0383(2010), Variable O&M for Conventional Coal Plant	24.3 $/MWh
Total Area Regulation Services Provided	Sandia Report SAND2010-0815, pg. 79. Assumes 50% of the year operation and because 1kW of storage can provide 2kW of storage the capacity of the device is multiplied by 2.	4380 hours × ES Power Capacity × 2
Average Price for Area Regulation	Sandia Report SAND2010-0815, pg. 79	38.5 $/MW-h
Energy Storage Capacity for Area Regulation	Sandia Report SAND2010-0815, pg. 79. Assumes twice the capacity of the storage device can be used for up and down regulation	ES Power Capacity
Conventional Capacity Required for Equivalent Level of Area Regulation	Sandia Report SAND2010-0815, pg. 79, Assumes energy storage can provide twice the regulation capacity compared to its nameplate rating.	ES Power Capacity × 2

Metric	*Source*	*Value/Equation*
Price of Conventional Capacity	Updated Capital Cost Estimates for Electricity Generation Plants, EIA, November 2010, Table 1. Updated Estimates of Power Plant Capital and Operating Cost, Conventional NGCC Overnight Capital Cost (2010 $/kW) + Fixed O&M Cost (2010$/kW) assuming 15% fixed charge rate for non-utility and 11% fixed charge rate for utilities	(978 $/kW × Annual Fixed Charge Rate + 14 $/kW) × 1000 kW/MWh
Total Spinning-Reserve Services Provided	Estimate based on total number of expected service hours (low end) for this service described in Sandia Report SAND2010-0815, pg. 80. the number of expected service hours are multiplied by the capacity of the energy storage device.	2000 hours × ES Power Capacity
Average Price for Spinning Reserve Services	Sandia Report SAND2010-0815, pg. 81, assume average value	4.5 $/MW-h
Total Non-Spinning-Reserve Services Provided	Estimate based on total number of expected service hours (low end) for this service described in Sandia Report SAND2010-0815, pg. 80. The number of expected service hours are multiplied by the capacity of the energy storage device.	500 hours × ES Power Capacity
Average Price for Non-Spinning Reserve Services	Ancillary Services: Technical and Commercial Insights, July 2007, Table E2	3 $/MW-h
Total Backup Supply Services Provided	Estimate based on total number of expected service hours (low end) for this service described in Sandia Report SAND2010-0815, pg. 80, the number of expected service hours are multiplied by the capacity of the energy storage device.	150 hours × ES Power Capacity
Average Price for Backup Supply Services	Ancillary Services: Technical and Commercial Insights, July 2007	0.4 $/MW-h

Metric	Source	Value/Equation
Marginal Operating Costs of Conventional Generation at Partial Load	EIA AEO 2011, DOE/EIA-0383(2010), Variable O&M for Conventional Combined Cycle Natural Gas Plant. Increased this value by 1.0% based on the increased fuel use of a plant providing regulation services as described in Emissions Comparison for a 20 MW Flywheel-based Frequency Regulation Power Plant, KEMA Project: BPCC.0003.001, Final Report with Updated Data, May 2007	45.6 $/MWh × 1.01
Marginal Operating Costs of Conventional Generation at Optimal Load	EIA AEO 2011, DOE/EIA-0383(2010), Variable O&M for Conventional Combined Cycle Natural Gas Plant	45.6 $/MWh
CO2 Emissions Factor of Generation at Partial Load	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas and is 5% worse than at optimal loading conditions.	1280 lbs/MWh × 1.05
CO2 Emissions Factor of Generation at Optimal Load	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas	1280 lbs/MWh
SOx Emissions Factor of Generation at Partial Load	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas and is 5% worse than at optimal loading conditions.	0.006 lbs/MWh × 1.05
SOx Emissions Factor of Generation at Optimal Load	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas	0.006 lbs/MWh
NOx Emissions Factor of Generation at Partial Load	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas and is 5% worse than at optimal loading conditions.	1.1 lbs/MWh × 1.05
NOx Emissions Factor of Generation at Optimal Load	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas	1.1 lbs/MWh
PM Emissions Factor of Generation at Partial Load	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas and is 5% worse than at optimal loading conditions.	0.04 lbs/MWh × 1.05
PM Emissions Factor of Generation at Optimal Load	http://www.infinitepower.org/calc_pollution.htm, Assuming generation comes from Gas	0.04 lbs/MWh

Metric	Source	Value/Equation
Annual Reactive Power Capacity Available for Voltage Support	Assumes the entire energy storage capacity can be used to provide reactive power.	ES Power Capacity
Annual Capacity Payment for Voltage Support	Ancillary Services: Technical and Commercial Insights, July 2007, Table E2	2000 $/MVAR-yr
Average Variable Operating Cost of Non-Congestion Generation	EIA AEO 2011, DOE/EIA-0383(2010), Variable O&M for Conventional Coal Plant	24.3 $/MWh
Annual Transmission Enhancement Benefit	Sandia Report SAND2010-0815, pg. 83	15.1 $/kW-yr
Number of Underfrequency Load-Shedding Occurrences	Sandia Report SAND2010-0815, pg. 83, Assumes approximately 4 occurrences every 10 years.	One occurrence in the second and fourth year.
Value of Avoided Load-Shedding Occurrences	Sandia Report SAND2010-0815, pg. 83, Assumes $12.8/kW per event	12.8 $/kW × ES Power Capacity
Total Hours of Congestion Avoided	Sandia Report SAND2010-0815, pg. 84	876 hours
Average Congestion Charge	Sandia Report SAND2010-0815, pg. 84	10 $/MW-h
Average Wholesale Price of Electricity	http://www.eia.gov/todayinenergy/detail.cfm?id=2510	50 $/MWh
Average Variable Operating Cost of Congestion Generation	EIA AEO 2011, DOE/EIA-0383(2010), Variable O&M for Conventional Combined Cycle Natural Gas Plant	45.6 $/MWh
Transmission Capacity Deferred		No default
Annual Fixed Charge Rate for Transmission Capital Investment	Same fixed charge rate used to amortize the cost of the energy storage deployment.	User input
Capital Cost of Deferred Transmission Capacity	Sandia Report SAND2010-0815, pg. 85	420 $/kVA
Yearly O&M Costs of Deferred Transmission Capacity		No default
Initial Year of Transmission Deferral	Same year as initial year of energy storage deployment.	User input
Final year of Transmission Deferral	Assume a 3 year deferral	User input + 3 years
Distribution Capacity Deferred		No default
Annual Fixed Charge Rate for Distribution Capital Investment	Same fixed charge rate used to amortize the cost of the energy storage deployment.	User input
Capital Cost of Deferred Distribution Capacity	Sandia Report SAND2010-0815, pg. 85	420 $/kVA
Yearly O&M Costs of Deferred Distribution Capacity		No default
Initial Year of Distribution Deferral	Same year as initial year of energy storage deployment.	User input

Metric	Source	Value/Equation
Final year of Distribution Deferral	Assume a 3 year deferral	User input + 3 years
Total Energy Discharged for TOU Energy Cost Management	Sandia Report SAND2010-0815, pg. 88. Assumes full storage power capacity is used for this application	720 hours × ES Power Capacity
Average On-Peak Retail Price of Electricity	Sandia Report SAND2010-0815, pg. 88	370 $/MWh
Average Off-Peak Retail Price of Electricity	Sandia Report SAND2010-0815, pg. 88	110 $/MWh
Average Monthly Load Reduction from ES at Peak	Assume the entire capacity of the battery is used to shed peak and that the battery capacity does not exceed the total off-peak load.	ES Power Capacity
Average Monthly Load Reduction from ES at Partial-Peak	Assume the entire capacity of the battery is used to shed peak and that the battery capacity does not exceed the total off-peak load.	ES Power Capacity
Average Monthly Load Reduction from ES at Off-Peak	Assume the entire capacity of the battery is used to shed peak and that the battery capacity does not exceed the total off-peak load.	ES Power Capacity
Peak Demand Charge	Sandia Report SAND2010-0815, pg. 90	11590 $/MW-month
Partial-Peak Demand Charge	Sandia Report SAND2010-0815, pg. 90	2650 $/MW-month
Off-Peak Demand Charge	Sandia Report SAND2010-0815, pg. 90	6890 $/MW-month
Outage Minutes Avoided by Residential Customers	Sandia Report SAND2010-0815, pg. 91	150 minutes
Outage Minutes Avoided by Commercial Customers	Sandia Report SAND2010-0815, pg. 91	150 minutes
Outage Minutes Avoided by Industrial Customers	Sandia Report SAND2010-0815, pg. 91	150 minutes
Average Hourly Residential Load Not Served During Outage	http://www.eia.gov/electricity/data.cfm#sales, 2011 data on electricity sales and customers from the Energy Information Administration	1.3 kW
Average Hourly Commercial Load Not Served During Outage	http://www.eia.gov/electricity/data.cfm#sales, 2011 data on electricity sales and customers from the Energy Information Administration	7.7 kW
Average Hourly Industrial Load Not Served During Outage	http://www.eia.gov/electricity/data.cfm#sales, 2011 data on electricity sales and customers from the Energy Information Administration	132.1

Metric	Source	Value/Equation
Residential VOS	Estimating the Benefits of the Energy Storage System Program Final Report Addendum: Benefit Calculation Methodology, DOE OE, July 2009	5 $/kWh
Commercial VOS	Estimating the Benefits of the Energy Storage System Program Final Report Addendum: Benefit Calculation Methodology, DOE OE, July 2009	10 $/kWh
Industrial VOS	Estimating the Benefits of the Energy Storage System Program Final Report Addendum: Benefit Calculation Methodology, DOE OE, July 2009	20 $/kWh
Number of Months that Demand Charges are Avoided	Sandia Report SAND2010-0815, pg. 90	5
Typical Number of Power Quality Events per Year	Sandia Report SAND2010-0815, pg. 94	10
Value of Avoided Power Quality Events	Sandia Report SAND2010-0815, pg. 94	5 $/kW peak load
Customer Peak Load	Navigant Assumption	1000 kW
Average Variable Renewable Generation Costs	Navigant Assumption	0 $/MW
Total Renewable Energy Discharged for Arbitrage	Sandia Report SAND2010-0815, pg. 97. Assumes full storage power capacity is used for this application	782 hours × ES Power Capacity
Total Renewable Energy Discharged for Energy Time-Shift	Sandia Report SAND2010-0815, pg. 97. Assumes full storage power capacity is used for this application	782 hours × ES Power Capacity
Effective Load Carrying Capacity of Renewable Post-Firming	Sandia Report SAND2010-0815, pg. 100	90%
Effective Load Carrying Capacity of Renewable Pre-Firming	Sandia Report SAND2010-0815, pg. 100	25%
Hours of Renewable Energy Capacity Sold	Assuming a capacity factor of 30%, 2630 hours of capacity can be sold into the market.	2630 hours
Nameplate Capacity of Renewable Resource		No default
Capacity Factor of Renewable Resource	Navigant Assumption	30%
Capital Cost of Conventional Voltage Support Solution	Based on an annual payment of $2000/Mvar and a fixed charge rate of 11% the total installed capital cost of a voltage support solution is $18/kVAR	18 $/kVAR

Metric	Source	Value/Equation
Nameplate Reactive Power Capacity of Energy Storage	Assumes the entire energy storage capacity can be used to provide reactive power.	ES Power Capacity
Annual Fixed Charge Rate for Voltage Support Capital Investment	Same fixed charge rate used to amortize the cost of the energy storage deployment.	User input
Capital Cost of Conventional Electric Service Reliability Solution		No default
Annual Fixed Charge Rate for Electric Service Reliability Capital Investment	Same fixed charge rate used to amortize the cost of the energy storage deployment.	User input

D.2 Criteria for Data Input Warning Flags

After the user has entered all input data and has clicked the button to proceed to the CM phase of the tool, the ESCT performs a data validation check on certain key metrics. This validation check determines if the values entered for key metrics are realistic given the technical characteristics of the energy storage solution. A warning textbox will alert the user if a value is deemed to be unrealistic. This section explains the criteria equations used to determine if a value is realistic.

Many of the key inputs use the same calculated parameter to determine if the values entered seem to exceed the operating limits of the storage systems for a desired application. This common parameter is the called the maximum reasonable annual discharge time. Because it is used in so many of the criteria equations, it is derived below, commented on, and then simply referenced the criteria equations in Table 15.

- Solve equation 2 for
- Substitute equation 3 into equation 1 and solve for

- Assume

–

Equation 5 is the equation used to estimate the maximum reasonable annual discharge time. This equation assumes the average rate of charge and average rate of discharge are the same and that both are equal to the nameplate charge rate of the storage system. This assumption may not always be true. For example, the nameplate charge rate may be larger than the discharge rate. Or, more likely, the storage system may discharge at a lower rate than its maximum nameplate discharge rate. However, it is also unlikely that the energy storage will always be either charging or discharging for all hours during the year, it is more likely that there will be some time in which the energy storage is in a type of standby mode. Therefore, equation 5 represents a conservative approximation of the maximum annual discharge time and is not a hard limit. Table 15 lists the exact criteria equation used to determine if a metric value has exceeded the reasonable operating limits of the storage system. This table also lists the rationale behind each equation.

Table 15. Validation Criteria for Key Metrics

Metric	*Criteria Equation*	*Rationale*
Total Energy Discharged for Arbitrage	x ES Nameplate Power Capacity	This equation calculates the maximum reasonable energy discharge.
Total Energy Discharged for Energy Time-Shift	x ES Nameplate Power Capacity	This equation calculates the maximum reasonable energy discharge.
Total ES Capacity sold	8760h x ES Nameplate Power Capacity	Theoretically, an owner could sell capacity to the market and never be called upon to discharge; therefore, an owner could sell 8760 hours of service.
Total Load Following Services Provided	8760h x ES Nameplate Power Capacity	Can load follow up and down (charge and discharge) so the theoretical maximum hours of service is 8760h.
Total Energy Discharged for Load Following	8760h x ES Nameplate Power Capacity	Can load follow up and down (charge and discharge) so the theoretical maximum hours of service is 8760h.
Total Area Regulation Services Provided	8760 x ES Nameplate Power Capacity x 2	Can sell up regulation and down regulation, therefore, a 1 MW battery can be paid to provide 2MW of service. Also because you get paid for up and down regulation so you can theoretically get paid for 8760 hours of service

Metric	Criteria Equation	Rationale
Conventional Capacity Required for same level of Area Regulation	ES Nameplate Power Capacity x 2	Can sell up regulation and down regulation, therefore, a 1 MW battery can be paid to provide 2MW of service. A conventional source would need to be sized at twice the size of the ES to provide the same amount of service.
Total Spinning-Reserve Services Provided + Total Non-Spinning-Reserve Services Provided + Total Backup Supply Services Provided	8760 x ES Nameplate Power Capacity	Theoretically, an owner could sell capacity to the market and never be called upon to discharge; therefore, an owner could sell 8760 hours of service.
Annual Reactive Power Capacity Available for Voltage Support	ES Nameplate Power Capacity	
Hours of Congestion Avoided		Can only provide this service when discharging.
Total Energy Discharged for TOU Energy	x ES Nameplate Power Capacity	This equation calculates the maximum reasonable energy discharge.
Avg. Monthly Load Reduction from ES	ES Nameplate Power Capacity	Can only reduce peak by the nameplate discharge capacity of the ES.
Total Renewable Energy Discharged for Arbitrage	x ES Nameplate Power Capacity	This equation calculates the maximum reasonable energy discharge.
Total Energy Discharged for Renewable Energy Time-Shift	x ES Nameplate Power Capacity	This equation calculates the maximum reasonable energy discharge.