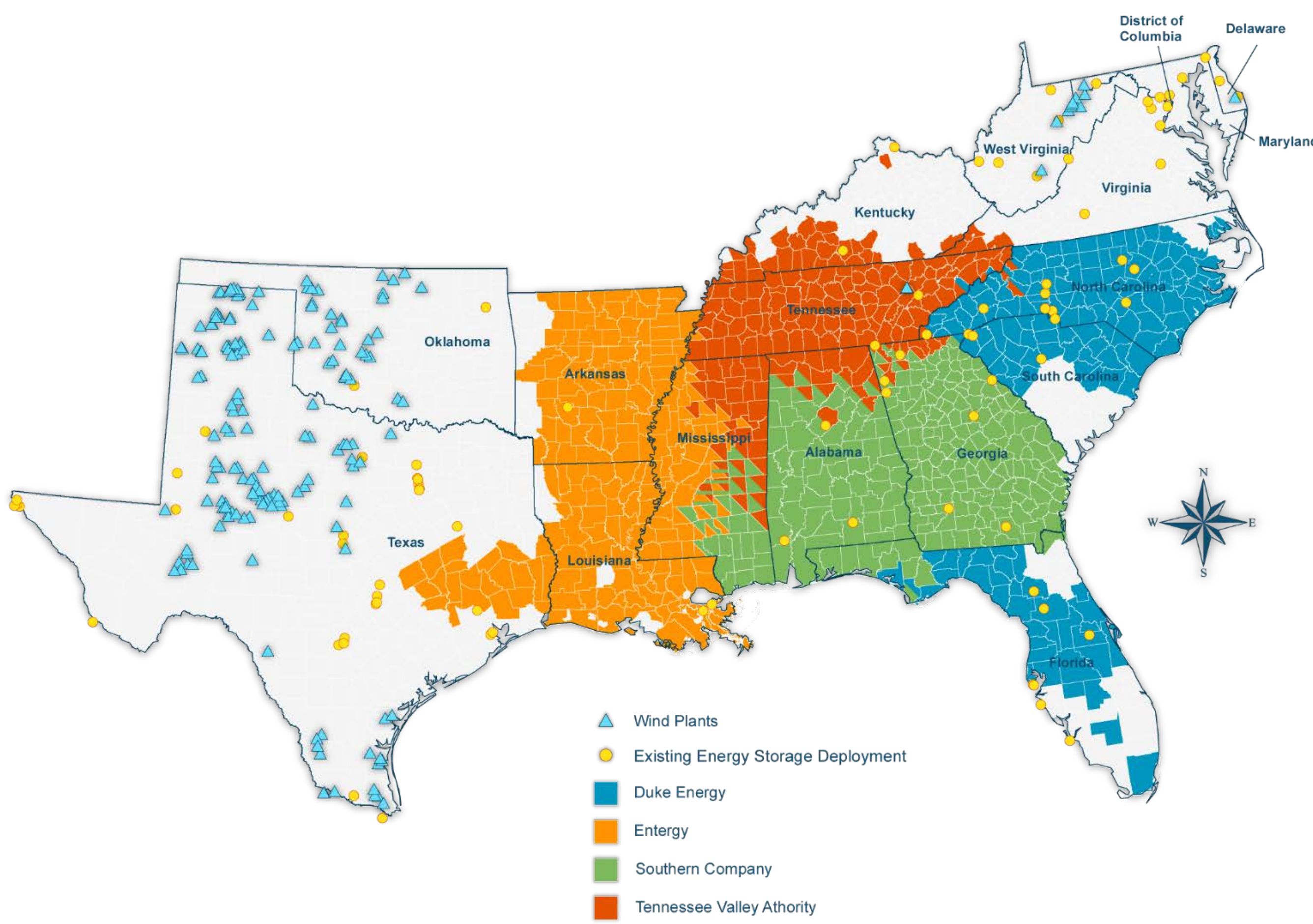
Utility Storage Integration Program: Prioritization of Energy Storage Needs in Southeastern U.S.

National Strategic Planning and Analysis Research Center and
Center for Advanced Vehicular Systems,
Mississippi State University

January 2018

Executive Summary

The purpose of this study is to examine the application and economic viability of grid-tied, utility-scale energy storage systems in the southeastern United States. Mississippi State University (MSU) conducted this study, which builds upon work previously published. One such recent study focused on the utility system operated by the Southern Company [1], with the goal of identifying and prioritizing relevant service scenarios (use cases) involving energy storage systems and then performing economic analyses that focused on so-called ancillary benefits of energy storage. One of the Sandia study conclusions was that the scope of future studies should be expanded to cover a larger range of possible benefits in support of utility operations and future planning. The Sandia report, as well as other authorities, have recommended that future studies estimate multiple types of benefits to compute total net economic value using the principal of stacked-benefit economic analysis. This study performs such an analysis and finds somewhat more positive economic results compared to previous studies for some use cases. In particular, the results suggest that, in some cases, utility-scale energy storage could in the near term be economically justifiable in the context of utility-planning principles, such as rate of return on assets and reasonable payback period, with acceptable technical and economic risk. MSU also expanded the region in which demonstrative example use cases could be located to include four utility-service areas covering much of the Southeast. The geographic scope of this study is defined by the following figure, which shows the customer service areas for Duke Energy, Entergy, Southern Co., and the Tennessee Valley Authority.



The study begins by describing five use cases for utility-scale energy storage derived from interviews of utility experts as well as other sources: (1) unservable load; (2) firming renewable energy; (3) importing renewable energy; (4) fossil fuel plant retirement; and (5) grid resiliency. Note that in some publications a "use case" is defined as a specific technical service or function in a specific location provided by an existing or planned energy storage project. In contrast, this report defines a use case as a broadly described utility problem that would normally trigger a study by the utility's planning department to resolve. Such studies often lead to major capital projects involving transmission or distribution system upgrades or even more costly new or expanded generation plants. The first four use cases studied in this report are examples of such problems. Since the power grid in the Southeast is large and complex, it was necessary to canvas much of the interconnected grid comprising all four major utilities serving the Southeast as communicating partners, themselves forming a part of the even vaster Eastern Interconnect, to adequately evaluate the use cases selected for this study. Often during the extensive power system simulations performed by MSU on a utility transmission model similar to the actual Eastern Interconnect, the diversity of the electric grid meant that a valid use case could be found only after searching much of the entire region. Nevertheless, examples of each of the first four uses cases were found somewhere within the southeastern U.S. power grid.

Since a common outcome of a utility-planning study on one of the first four use cases is a major capital investment made by utilities and passed on to consumers, the primary or "base" benefit of the net benefit stack computed during the analysis for each use case is either a transmission system deferral or a generation plant deferral. The delays of large capital outlays resulting from such deferrals are exactly the kind of economic benefits needed to justify near-term investments in energy storage. In the case of this report, capital deferrals were indeed found to be the most valuable benefit of the proposed energy storage projects.

The fifth use case in this study was handled differently. For this use case, MSU performed a broad and comprehensive review of the threats posed by a number of natural perils. These perils are known to cause widespread and long-lasting power outages from time to time across wide areas of the Southeast. One obvious example is a tropical storm such as a hurricane. This study also discusses frontal systems that produce thunderstorms with consequent high winds, tornadoes, and heavy flooding, along with ice storms and earthquakes. The fifth use case narrative then examines the costs of such disruptions and itemizes the enormous ratepayer-borne investments made by utilities to harden their systems from such perils. The authors propose the possibility of allowing widespread "islands" to form across the utility system following natural disasters using energy storage so that islands can operate efficiently while repairs are made to the electrical grid. While the fifth use case narrative recognizes that islanding the utility system is essentially not permitted by policy at this time, current and future microgrid research could lead to the feasibility of ad hoc "mini-grids" to form after natural disasters and thus limit the cost and misery of widespread power outages. Such power outages often affect larger areas more than the high wind and flooding aspects of such perils.

The methodology used to compute the estimated net stacked benefits for each of the first four use cases in this report was two-fold. First, we identified a location within one of the four utility service areas that represents an example of the conditions assumed to define the utility service problem associated with the use case. Then a power system analysis using a model similar to the actual Eastern Interconnect was performed by power systems engineers at the Center for Advanced Vehicular Systems (CAVS), in collaboration with faculty and students within the MSU Bagley College of Engineering, to compute a technical solution to the utility problem with a utility-scale energy storage project. This technical solution encompasses information such as energy capacity in MWhr and power rating in MW but does not model the particulars of the energy storage technology underlying the project, as that detail was saved for the second part of the analysis. The data computed are similar to those that a utility planning department might compute in an actual case. These data were then fed to the second half of the analysis.

Second, a team from the National Strategic Planning and Research Center (NSPARC) combined the power systems technical data with economic and other operational data related to utility operations and fed those parameters into the Energy Storage Computational Tool (ESCT). The ESCT is an Excel-based program created by Navigant Consulting to assess the benefits and costs of energy storage systems. This program is intended to be used by a variety of stakeholders (e.g., regulators, utilities, researchers) to evaluate either operational or proposed/hypothetical energy storage deployments. The framework underlying the ESCT is based on two primary sources. The first source is the analytical approach used in the more general Smart Grid Computational Tool (SGCT) that the U.S. Department of Energy developed in conjunction with Navigant as a means for consistently assessing the economic merits of smart grid projects. The other source is the methodology described in the 2010 Sandia National Laboratories guide to measuring energy storage's market potential.

The ESCT can be used to produce monetary estimates of the stacked benefits of an energy storage system. The specific types of energy storage benefits the ESCT can monetize include electricity arbitrage, deferral of investment in generation capacity and transmission systems, improvement in grid resiliency, and emissions reductions. Furthermore, the program can disaggregate the returns achieved through an ES deployment by the type of stakeholder the returns accrue to, such as ratepayers/utilities, non-utility merchants, end-users, and general society.

The outputs of the ESCT computed for each of the first four use cases inform the major conclusions of this report. These results are quantitative and extensively covered in the main portion of this document. An overarching assessment of the data includes the following findings:

- Capital deferrals for utility infrastructure improvements to support load growth from new economic development projects are significant enough to pay for a battery storage facility located near the end of major transmission lines. This opportunity can lead to advantages for communities that might otherwise lose a major economic development opportunity because of delays in upgrading or adding new transmission lines—delays that, in more urban or ecologically sensitive areas, can be considerable (i.e., years). The relative size of the battery energy storage project computed for Use Case 1 would allow the installation of the project with little or no impact on the community and thus would be completed rapidly and within budget.

- The recent total eclipse of the sun that crossed the North American continent on August 21, 2017, highlighted a growing recognition that integration of intermittent renewable energy has limits. The political climate of the Southeast requires market-based renewable energy, which means political limits on the subsidy that ratepayers will accept for renewable energy portfolios. Nevertheless, there is market pull from customers such as Walmart Inc., as well as others, for utilities to include renewable energy in the generation mix within the Southeast. Use Case 2 demonstrates that energy storage is an economically feasible option in the North Carolina service area to help "firm" the high rate of solar energy penetration in that state while reducing the need to build natural gas-fired fossil fuel plants.

- A feature unique to the Southeast is the lack of wind-based renewable energy. However, plentiful wind energy in West Texas and in the Midwest could be imported with existing or planned transmission systems. However, much of this energy is available "off peak" and thus would be more valuable and provide more Southeastern energy needs if it could be stored in bulk energy storage between the western sources and the eastern loads. An advantageous trend is examined in Use Case 3 where recent increases in the supply of natural gas in the Louisiana and East Texas region has reduced the need for seasonal storage of natural gas. At the same time, Louisiana is experiencing among the highest rates of electric load growth in the nation due in part to this ready supply of natural gas for new industrial development and expansion. Use Case 3 shows that billions of dollars in new power plant construction could be deferred by repurposing existing natural gas storage facilities into bulk energy storage facilities based on compressed air energy storage technology. In the Use Case 3 analysis, existing storage sites are identified in geographically ideal locations between wind generation assets and new electrical loads and are shown to have enormous economic potential for the Southeast.

- On August 23, 2017, the U.S. Department of Energy released the Staff Report to the Secretary on Electricity Markets and Reliability. In that report, a variety of economic factors were cited to explain the closure of numerous older coal-fired generation plants around the country, especially in the Southeast. A typical result of such closures are realignments of transmission systems and possibly new generation that represents enormous capital costs. It is hypothesized in Use Case 4 that one such planned closure announced by Duke Energy could be better managed with a modest 50 MW energy storage project based on battery technology or above-ground compressed air storage. However, despite the opportunity for capital deferral as well as other stacked benefits from ancillary services, all technology options resulted in net negative stacked benefits as calculated by the ESCT, and thus an economically viable solution to the planned closure of the coal plant based on utility-scale energy storage was not found. Nevertheless, Duke Energy has announced the intention to seek regulatory approval for a 9 MW lithium-ion battery energy storage facility to be located in the vicinity of a coal-plant closure and natural gas replacement in Asheville, North Carolina, which is located in the Western Appalachian service region of Duke Energy. The purpose of the energy storage facility is to provide real time grid support services similar to that suggested by the power systems analysis supporting Use Case 4.

- In Use Case 5, a long-term opportunity is proposed that will allow a transformational change in the way the grid can respond to infrequent but high-impact natural perils. Modest amounts of utility-scale energy storage distributed in strategically selected ways across a 21st-century electric grid, with both conventional generation and significant amounts of distributed energy resources, could allow ad-hoc networks of power islands to maintain service over large areas isolated from each other by major damage to interconnecting infrastructure. This report shows that billions of dollars are being invested to harden the power grid throughout the Southeast. It is proposed that some of these investments can be used as a kind of "insurance premium," which will augment the stacked benefits of energy storage when combined with conventional capital investments intended to improve the operation of the power grid as considered in Use Cases 1, 2, and 4. This "insurance premium" could be a critical factor in determining whether certain energy storage projects yield positive net stacked benefits.

- Overall, of the four use cases analyzed using the stacked benefits method, three have net positive economic benefits in locations within the service areas of the four major utilities defining the scope of the Southeast in this study. The most attractive scenario is Use Case 3, which shows that an opportunity unique to the Southeast exists to enable imports of renewable energy based on wind from western locations, where a sufficient amount of wind energy is generated at night to be time-shifted for use by the rapidly growing load centers in the industrial regions in and around Louisiana.

Table of Contents

I. Introduction

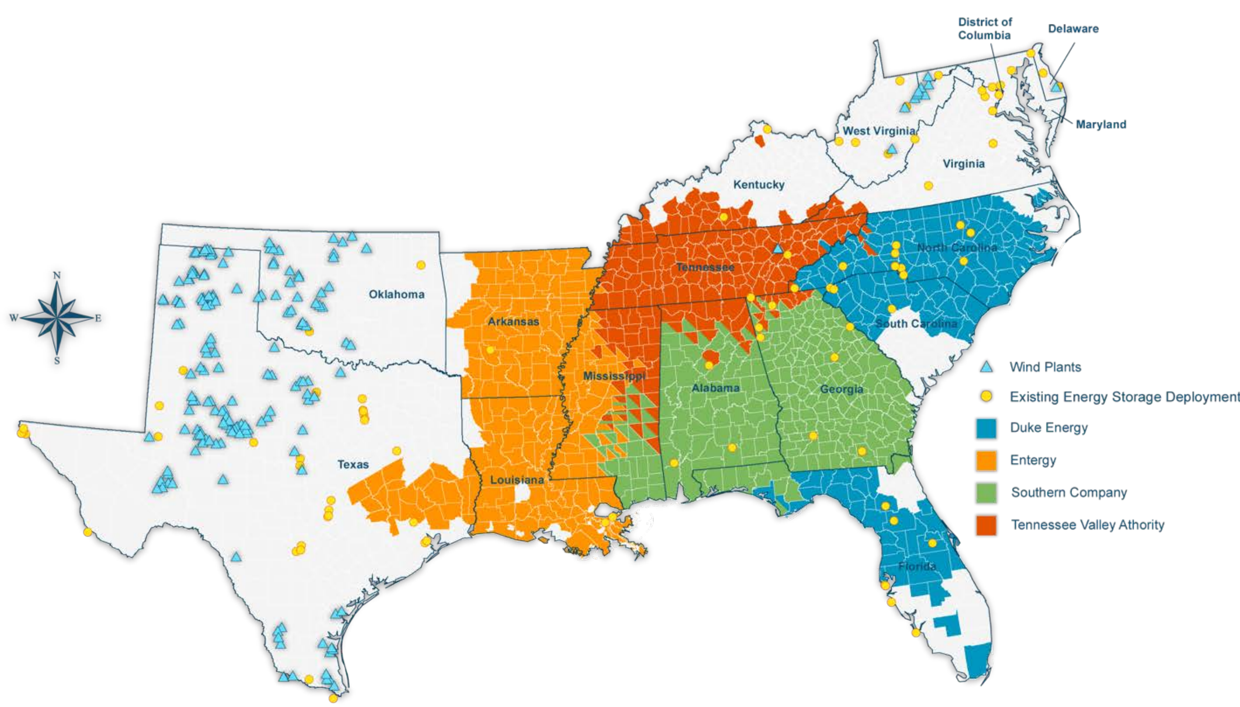
Scope

The purpose of this project is to examine the application of grid-tied energy storage systems in the southeastern United States. Mississippi State University (MSU) was specifically tasked with identifying and prioritizing relevant service scenarios (use cases) for which energy storage systems would apply in the Southeast based upon a stacked benefit economic analysis. To achieve these objectives, MSU performed extensive research and interviewed utilities throughout the Southeast to help develop use-case scenarios for energy storage.

II. Overview of Grid-Tied Energy Storage

An assessment of installed energy storage projects within the southeastern service area of four major utilities, which comprise the definition of the southeastern United States used for this study (see Figure 1), was performed to understand the maturity and penetration of this technology in the region. Analyzing the potential for energy storage in the Southeast specifically is worthwhile considering how the region's distinctive social and environmental characteristics could influence the viability of energy storage deployment. For instance, state-level renewable energy portfolio requirements are less common in the South than in other parts of the country, reducing political pressures that favor construction of energy storage systems. However, there are notable shifts toward utilization of solar power by some groups of southern consumers such that energy storage technology may eventually be of value in firming regional electric systems. Moreover, the regular threat of severe weather events in the South potentially enhances the prospects of using energy storage to improve grid resilience.

1: Southeastern electric utility service areas, existing energy storage deployments, and existing regional wind-based renewable energy that define the regional scope of this study



One primary source for understanding the background of this project was the 2013 Southern Company Energy Storage Study prepared by Sandia National Laboratories [1]. This report focused on the evaluation of a business case for additional utility-scale energy storage in the Southern Company system. Publicly available data were used to build a model of the system. The conclusion of the report was that additional bulk-scale energy storage did not appear to be justifiable based on the following:

- **Anticipated generation fleet and natural gas prices.**
- **System savings were still well below levels for economic justification, even with high renewable penetration.**
- **Too small of a difference in price between on-peak and off-peak energy.**
- **Resource diversity of the power system.**

Even though the bulk of the report's conclusions were unfavorable with respect to the business case for grid-tied energy storage in the Southeast, the authors noted several limitations in the data and methodology of the study. First, transmission and distribution applications were not examined in this study, so it was assumed that no transmission constraints existed or that there was no value for distribution-level applications. Second, the primary focus of the study was to find annual system savings, so it was assumed that such savings were a reasonable estimate of the total benefit going forward, which may have led to inaccurate net present value (NPV) calculations. Third, the NPV calculations were sensitive to assumptions on the discount rate, inflation, and battery stack life and replacement cost. Fourth, the study used an approximation of Southern Company's reserve specification. In light of these limitations, it was recognized by the sponsor of this study that the concept of "stacked benefits" was needed to reassess the study's conclusions. Therefore, in order to meet the requirement in the statement of work to prioritize and estimate the stacked benefits of energy storage projects, MSU has expanded the previous study's methodology to incorporate the point of view of utility project planners responsible for energy delivery (transmission) and energy production (generation). We believe this study's methodology builds on past studies in the way intended by the previous study authors. From our analysis, there emerges a stronger economic case for energy storage technology serving as a tool for addressing utility project needs within the Southeast.

III. Use Case Overview

For the purposes of this report, a "use case" is defined as a broad utility-planning problem where energy storage could provide a solution. The use cases described in this report are non-location-specific descriptions that could spawn many potential projects.

As a first step into the utility realm for energy storage, the MSU team developed high-value energy storage use cases through consultation with experts in the electric power sector. First, MSU conducted exploratory interviews with two local electric power resellers within the TVA rate area to obtain a ground-level perspective on the potential uses of energy storage technology. Insights gained from these distribution perspectives were used to develop and refine energy storage questions that were later posed to electric utilities. The MSU team sought interviews with energy storage experts working for several regional utilities (i.e., Entergy, Southern Company, Duke Energy, and TVA). To date, MSU has conducted interviews with technical representatives of TVA, Entergy, and Southern Company; discussed energy storage goals with senior management of Duke

Energy; and drawn on extensive public-domain sources published by government agencies, utility companies, and non-governmental organizations. Based on the information obtained, MSU developed a list of high-value use cases for energy storage applications that are reflective of the southeastern United States. MSU has shared these use cases with utility partners and Southern Research (who is conducting a parallel study) to ensure that the proposed scenarios satisfy industry priorities.

MSU has thus far identified five use cases in which energy storage technology has the potential to be effectively deployed in the Southeast. These use cases include (note: ordering does not indicate priority):

***1. Unservable load growth*.**

a. Conventional response: Build new generation, transmission, and/or distribution infrastructure.
b. Energy storage option: Eliminate violations serving new load increments for some period of time and for limited load increments.
c. Financial benefits of pursuing the energy storage option:
  i. Capital cost deferral (primary stack).
  ii. Ancillary services (secondary stacks).
d. Utility validation: Southern Company gave one example (in the Panama City, Florida, area) of a feeder that limits the ability to serve a new shopping center. An example in the TVA rate area is given in the side bar as part of the Use Case 1 narrative.
e. Assumptions:
  i. Adequate generation in system.
  ii. Energy storage asset responds fast enough to load variations (ramp/power).
  iii. Energy storage asset support loads for duration needed (energy).

2. Firming utility-scale solar power at high penetration levels.

a. Conventional response: Build conventional generation to “firm” the solar.
b. Energy storage option: Combine solar assets with energy storage assets to “firm” the solar.
c. Financial benefits of pursuing the energy storage option:
  i. Premium for “firm” renewables (primary stack).
  ii. Ancillary services (secondary stacks).
  iii. Reduced risk of conventional fuel cost increases (gas) (tertiary stack).
d. Utility validation: Georgia Power RFPs for new solar.
e. Assumptions:
  i. Cost of un-firm solar competitive with that of natural gas.
  ii. Customer requests for renewable energy drive demand for new capacity (i.e., market-based renewable energy penetration).
  iii. Premium for firm solar available.

***3. Expanded importation of wind energy from western sources by energy time shift*.**

a. Conventional response: Build new generation infrastructure.
b. Energy storage option: Eliminate time-of-day overloads and time-shift energy.

c. Financial benefits of pursuing the energy storage option:
   i. Capital cost deferral (primary stack).
   ii. Ancillary services (secondary stacks).
d. Utility validation: Southern Company said transmission can sustain current wind contracts, but growth may be constrained.
e. Assumptions:
   i. Bulk energy storage technology other than pumped hydro feasible.
   ii. Appropriate sites available.

***4. Retirement of fossil fuel generation*.**

a. Conventional response: Build new infrastructure (generation, transmission).
b. Energy storage option: Eliminate violations serving existing and new loads after retirement of the fossil generation asset.
c. Financial benefits of pursuing the energy storage option:
   i. Capital cost deferral (primary stack).
   ii. Ancillary services (secondary stacks).
   iii. Future unconstrained economic growth (tertiary stack).
d. Utility validation: Duke Energy plans in the public domain.
e. Assumptions:
   i. Adequate generation in system.
   ii. Energy storage asset responds fast enough to load variations (ramp/power).
   iii. Energy storage asset support loads for duration needed (energy).

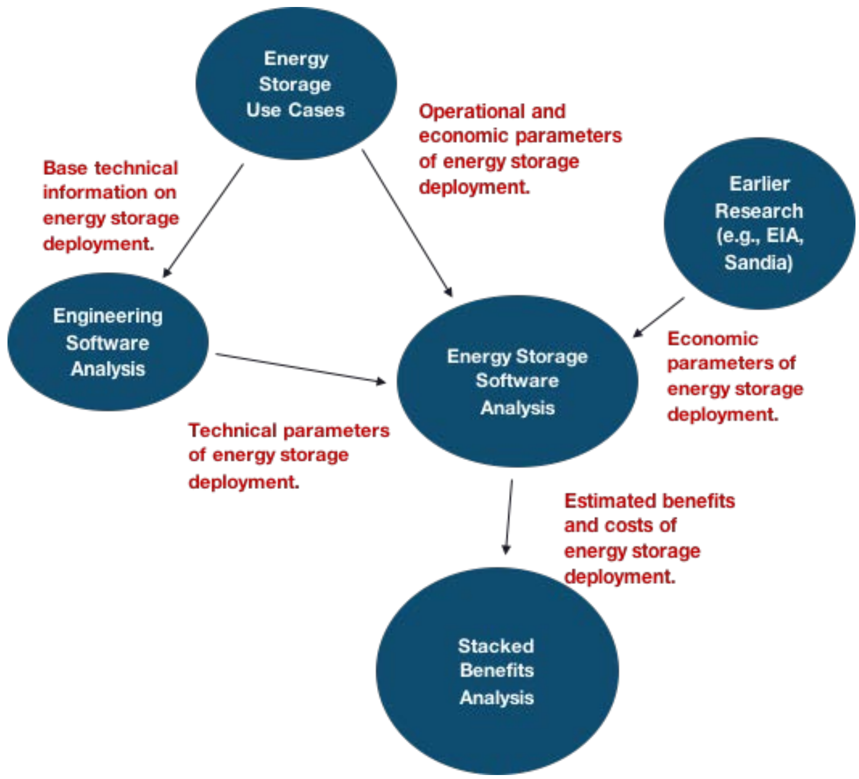
***5. Grid resiliency in event of natural disasters*.**

a. Conventional response: Upgrade infrastructure, limit outages.
b. Energy storage option: Limit duration and reach of large-area outages by enabling the grouping of central and distributed generation resources into stable functioning islands while the interconnecting system is repaired.
c. Financial benefits of pursuing the energy storage option:
   i. Avoidance of lost economic output (primary stack).
   ii. Operation of generation assets that would otherwise be stranded (secondary stacks).
d. Utility validation: Improving grid resiliency is a high priority based on public statements and media reports indicating that upgraded infrastructure limited outages from Hurricanes Matthew and Irma.
e. Assumptions:
   i. Utility has long-term policies and planning to utilize distributed infrastructure during a large outage by islanding.
   ii. Energy storage can provide power and energy to stabilize an ad-hoc island.

IV. Methodology

To determine the potential for energy storage in the Southeast, both a power systems analysis and an economic assessment were performed on four of the five use cases (use case five utilized a different method due to the limited available information) in order to realize the stacked benefits of potential projects addressing each use case. CAVS utilized power systems engineering software tools to provide input to the economic tool that in turn NSPARC used to compute the stacked economic benefits of one or more energy storage options in each use case. This work flow is depicted in Figure 2.

Figure 2: Flow Chart of the Process Used to Identify Stacked Benefits



A. Power Engineering Software Analysis

MSU has two custom tools that were used in the power systems analysis shown in Figure 2. These tools are summarized in Appendix A. One is a custom script called "Load Serving" that runs with a utility transmission system model in PowerWorld. The Load Serving tool allows the user to define a specific area with a graphical interface, and the script then automatically determines the amount of load that can be served in that area. The other tool is a custom script called "Corrective Action" that runs with a utility transmission system model in PSS/E. The Corrective Action tool automatically evaluates where problem areas exist in the network and what corrective actions could be taken to resolve violations caused by various contingencies in the system.

B. Economic Software Analysis

Open-source tools for economically evaluating grid-tied energy storage were sought to perform the stacked benefit analysis. One such tool investigated was the Energy Storage Computational Tool (ESCT). The ESCT is an Excel-based program created by Navigant Consulting to assess the benefits and costs of energy storage systems. This program is intended to be used by a variety of stakeholders (e.g., regulators, utilities, researchers) to evaluate either operational or proposed/hypothetical energy storage deployments. The framework underlying the ESCT is based on two primary sources. The first source is the analytical approach used in the more general Smart Grid Computational Tool (SGCT) that the U.S. Department of Energy developed in conjunction with Navigant as a means for consistently assessing the economic merits of smart grid projects. The other source is the methodology described in the 2010 Sandia National Laboratories guide to measuring energy storage's market potential [2].

The ESCT can be used to produce monetary estimates of the stacked benefits of an energy storage system. Specific types of energy storage benefits the ESCT can monetize include electricity arbitrage, deferral of investment in generation capacity and transmission systems, improvement in grid resiliency, and emissions reductions. Furthermore, the program can disaggregate the returns achieved through an ES deployment by the type of stakeholder the returns accrue to, including ratepayers/utilities, non-utility merchants, end users, and general society.

A second tool considered for energy storage economic analysis is the Storage Value Estimation Tool (StorageVET) developed by EPRI. This tool is primarily intended to develop detailed cost estimates of an energy storage project and thus is better suited for a follow-on study performing a detailed analysis after a potential project is selected from a use case analysis. The input information needed by the StorageVET tool involves detailed operational data that a utility would typically have available. Therefore, if a utility pursues recommendations from this study, a StorageVET analysis will likely be essential.

V. Use Cases

A. Use Case 1: Unservable Load Growth

1. General Narrative

A common use case involves a large industrial customer proposing a new load that is unservable by the transmission system in the local area identified for the new plant or upgrade. In this case, the location and amount of power required may necessitate upgraded or new transmission lines and/or substation equipment in order to feed the expected load. The ability of the utility company to serve this new load in a timely manner is often a significant factor in the decision to build a facility in a particular location. Therefore, this use case illustrates the possibility of using energy storage to defer the transmission investment needed to feed the new load with short notice but only over a limited period of time. The use case also considers two supplementary applications: electric energy time-shift and voltage support. Although local conditions vary greatly, the conditions assumed for the transmission system examined in this use case analysis are readily discoverable throughout the Southeast.

2. Power System Analysis

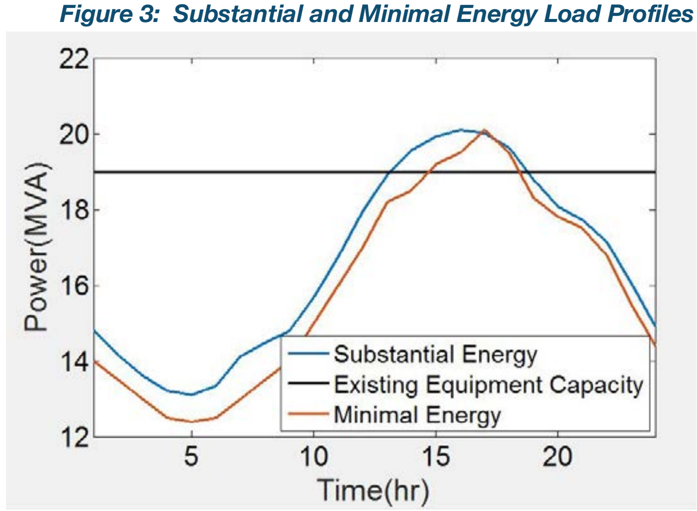
This use case postulates a rural area in the Southeast that has access to an existing 69 kV transmission system with a line nearly at capacity feeding the area. Two examples of this type of scenario were quickly identified through the analysis of two different power system models of the Eastern Interconnect, with the possibility for others. Once the potential transmission planning project was recognized through identification of the appropriate loading condition (see Table 1), an upper and lower bound for the load profile was applied to the local transmission system derived from data representative of the Southeast as described next. Both cases represent radial 69-kV loads, which are found in the two system models available to this study. Because they are radial loads, the analysis in the Sandia report “Electric Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage” [3] can easily be used to size an appropriate energy storage system. The sidebar illustrates an historical event that parallels the generic use case.

Table 1: Characteristics of Existing 69kV Lines

Case	Line Capacity (MVA)	Current Load (MVA)	Added Load (MVA)
Case1	19	18	2
Case2	100	93	10

The size of the required energy storage facility and the estimated size of the transmission system capacity upgrade deferred by the proposed energy storage facility were based on the previously mentioned Sandia report [3]. While the peak profile is available in power system models of the Eastern Interconnect available to MSU, the hourly load data are not and thus were estimated from other sources, in particular load profile data for the Southeast region provided by the U.S. Energy Information Administration [4]. The load profile obtained from this source was used to create the dataset named "Substantial Energy" and was used as an upper bound of the hourly load profile in Use Case 1. The dataset named "Minimal Energy" was used as the lower bound to investigate the sensitivity of the economic analysis to the hourly load profile. The Minimal Energy dataset was created on the assumption that the loading of the local system is "less peaky" compared to the EIA data averaged across the Southeast. "Less peaky" is quantitatively reflected by a peak duration that is shorter, representing an optimistic scenario where a smaller energy storage unit can defer a significant transmission investment. The standard load profile of the EIA data represents the least optimistic scenario for energy storage system sizing considered in Use Case 1, while the "less peaky" load profile represents the most optimistic scenario. Figure 3 shows the two load profiles that are used in this study to perform a sensitivity analysis of the economic assessment. The less peaky load profile turns all economic assessments net positive and thus represents the upper bound of economic value reported for Use Case 1. The EIA data, in contrast, lead to mixed economic results for the resulting energy storage system capacities.

Figure 3: Substantial and Minimal Energy Load Profiles



While this report is focused on the transmission system, it is important to note that the same analysis is applicable to much smaller energy storage units intended for the distribution level.

The following permutations of Use Case 1 assumptions were used to bound the economic analysis with multiple proposed energy storage project capacities and technical requirements driving the inputs to the ESCT:

- **Two step loads.**
  - 2 MW customer comes to a rural city of about 5,000.
  - 10 MW customer comes to a rural city of about 20,000.
- **Two base load growth rates.**
  - 0% assumes stagnated distribution-level load growth.
  - 2% assumes distribution-level load growth in the upper quartile for the Southeast.

- **Two energy storage capacity levels.**
  - "Substantial Energy" – this dataset used to size each energy storage project is based on the EIA hourly load profile for the Southeast.
  - "Minimal Energy" – this dataset used to size each energy storage project is based on an hourly load peak duration scaled down from the southeastern average.

For the purposes of the analyses here, average retail load growth in the southeastern states was calculated using EIA electricity retail sales data from 2014-2015 for southeastern investor-owned, cooperative, and municipal utilities with either 1,000-5,000 customers or 19,000-25,000 customers. In observing change in annual retail sales from 2014 to 2015, the 75% percentile for utilities with a smaller customer base and the 85% percentile for utilities with a larger customer base experienced a 2% increase in retail sales of electricity. Accordingly, the default 2% load growth is used for analyses in this report that assume load growth. However, certain permutations assume a static load with 0% growth. In estimating the sensitivity of the economic analysis due to retail load growth, 2% load growth serves as the upper bound, while 0% load growth serves as the lower bound.

The energy storage units were sized in power output and energy capacity with a methodology based on the Sandia report, while other technical inputs, such as round trip efficiency, cycle life, battery life, etc., were gathered primarily from the Electricity Storage Handbook [5]. The following section discusses inputs of importance.

Given the focus of Use Case 1, each permutation assumes that the storage technology is deployed in the year 2022 by a utility within a regulated market of the SERC Reliability Corporation.

Only battery technologies are considered in Use Case 1 given the lower power and energy levels required by the scenarios, in turn reflecting the generally smaller scale of the utility planning problem represented by Use Case 1. The following types of batteries were examined: lithium ion, lead acid, advanced lead acid, iron chromium, sodium sulphur, vanadium redox, zinc air, and zinc bromide. Table 2 represents some of the inputs into the ESCT. The inputs were obtained from the Electricity Storage Handbook [5]. Based on quotes from vendors provided in [5], it is assumed that the cycle life of all battery types is sufficient to cycle once per day for the lifetime of the unit. It is assumed that the battery will cycle one full cycle per day. Because the ESCT is a high-level analysis tool, many of the details of the energy storage plant's internal operating characteristics, such as depth of discharge, ramp rates, etc., are neither needed nor considered in this analysis.

It was noted that the round trip efficiency, while included in the input list and in the resulting equation for calculating reduced electricity cost found within the ESCT manual, did not seem to affect the actual calculation in the tool. Thus, the team used the equation found in the manual and manually updated the reduced electricity cost to reflect the round trip efficiency of the different battery technologies.

Table 2: Characteristics of Battery Technologies for Use Case 1

Type	Round Trip Efficiency	Total Installed Cost ($/kWh)	O&M Cost ($/kWh)
Lithium Ion	90%	440	5
Lead Acid	90%	593	12
Advanced Lead Acid	90%	593	12
Iron Chromium	75%	544	16
Sodium Sulphur	75%	468	7
Vanadium Redox	75%	487	12
Zinc Air	80%	261	7
Zinc Bromide	60%	699	21

3. Economic Analysis

Using the ESCT to estimate the costs and benefits of energy storage deployments for Use Case 1 required the specification of values for several ESCT inputs representing economic and market conditions. These inputs fall into five broad categories: general economic inputs; energy storage cost inputs; deferred transmission inputs; generation cost inputs; and emissions-related inputs.

General economic inputs. The general economic inputs include the average inflation rate and the discount rate. The inflation rate value used in the analysis is equal to the compound annual growth rate in the Consumer Price Index for the South Urban Area over the 2010-2016 period. The discount rate value utilized is the estimated after-tax weighted cost of capital reported in the DOE/EPRI Electricity Storage Handbook [5].

Energy storage cost inputs. Energy storage cost inputs include deployment's total installed cost, average yearly operating and maintenance (O&M) cost, fixed-charge rate, and expected decommissioning and disposal cost. The values used for total installed cost and O&M cost were derived from Lazard [6]. This up-to-date source provides marginal installed and O&M cost figures (in $/kWh) for several different types of energy storage technology. To obtain estimates of the total installed cost and average yearly O&M cost of each hypothetical energy storage deployment, the energy storage capacity of the respective device was multiplied by the lower-bound installed cost figure and lower-bound O&M cost figure provided by Lazard for that technology. Lower-bound costs were assumed based on the tendency for the expenses associated with battery technology to fall over time. The fixed-charge rate used in the analysis is equal to the midpoint of the range of fixed-charge rates typically paid by investor-owned utilities reported by Shaalan [7]. Values for energy storage decommissioning/disposal costs were calculated with an estimate provided by Battery Solutions of the price of recycling a lithium ion battery (in $/pound). Two decommissioning cost values were utilized throughout the analysis, one in the 2 MW scenarios and the other in the 10 MW scenarios irrespective of battery technology. Because, in the authors' opinion, distinguishing decommissioning costs by technology would have required speculation, the decision was made to not allow decommissioning costs to distinguish technologies in the economic assessment.

Deferred transmission inputs. The deferred transmission inputs consist of transmission capacity deferred, the capital cost of deferred transmission capacity, and the annual fixed-charge rate for transmission capacity investment. The values utilized for transmission capacity deferred are based on the assumption that the transmission upgrade that would occur without storage deployment would expand the overall power of the transmission system by 33%. This value is drawn from the Sandia energy storage analysis conducted by Eyer and Corey [2], who observe that transmission upgrades usually increase capacity by 25 to 50%. The capital cost of deferred transmission capacity was calculated using a California-based estimate of the median marginal cost (in $/kW) of upgrading a transmission node [2]. Once again, the fixed-charge rate is equal to the midpoint of the range of fixed-charge rates normally paid by investor-owned utilities reported by Shaalan [7].

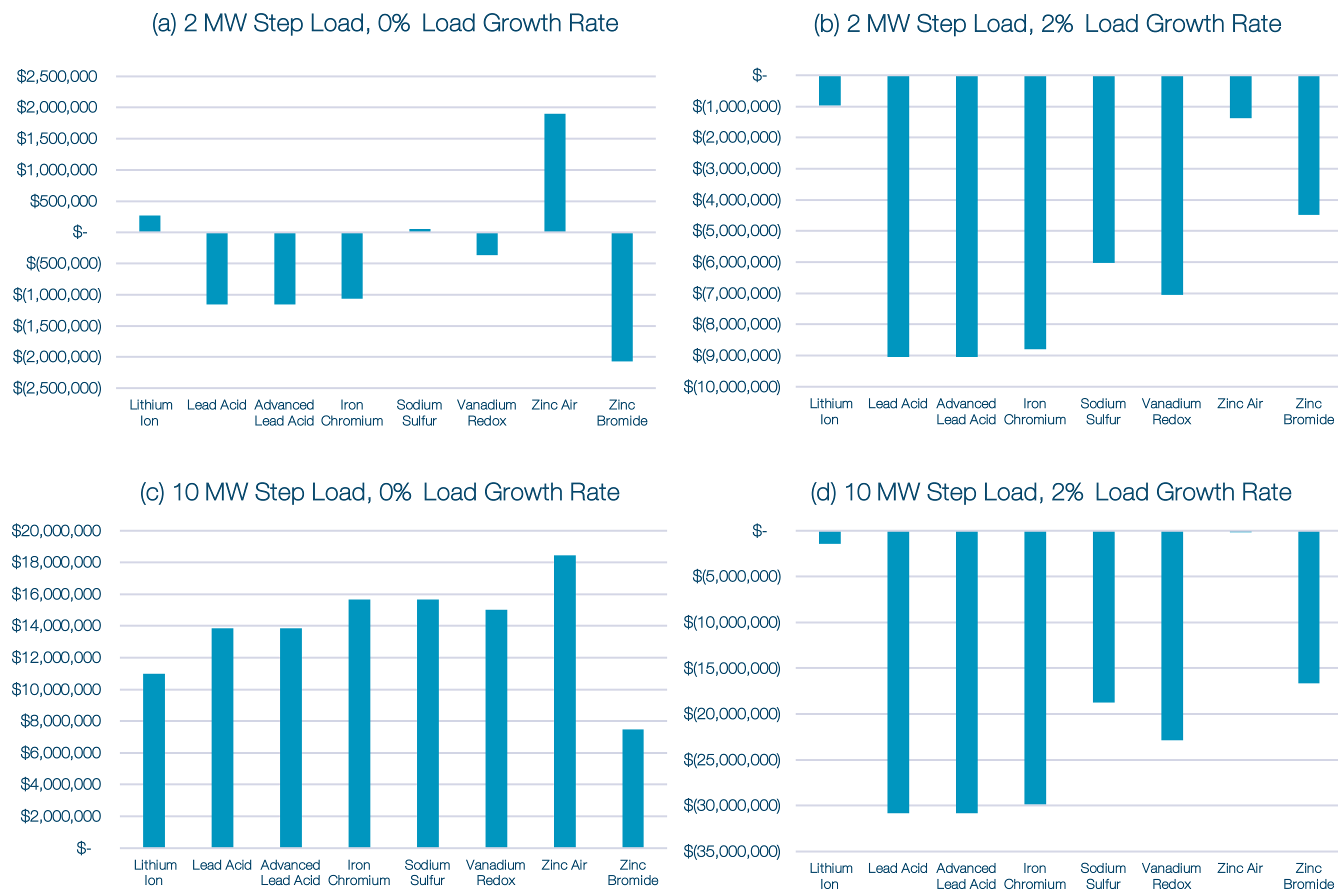
Generation cost inputs. The generation cost inputs include the average variable peak generation cost and average variable off-peak generation cost. A recent U.S. Energy Information Administration (EIA) estimate of the average variable O&M cost of conventional combined-cycle natural gas generation was used to measure the former, while the corresponding cost figure for conventional coal generation was used to measure the latter [8].

Emissions-related inputs. The emissions-related inputs include the emissions factors and value of sulfur-oxides (SOx) and nitrogen-oxides (NOx). These two gas-emission classes were considered in the analysis because they possess tangible value owing to their inclusion in emissions trading systems. CO_2 emissions can also be examined with the ESCT but were not considered because CO_2 is not subject to a trading system and thus cannot be readily assigned a monetary value. ESCT default inputs were relied on in determining emissions factors. The figures used in the analysis to represent the value of SOx and NOx are based on allowance trading price quotes for these gases supplied by Evolution Markets.

4. Results

Substantial Energy Scenario. Figure 4(a) shows that permutations consisting of various technologies in scenarios with a 2 MW step load and a retail load growth rate of 0%. The results were, by and large, not profitable or only marginally profitable (i.e., lithium ion and sodium sulfur chemistries). Among those with net positive benefits, the zinc air-battery technology was calculated to be the most likely to provide adequate value in this scenario, producing a total net benefit of approximately \$2 million. Figure 4(b) shows results of permutations with a 2 MW step scenario and a retail load growth rate of 2%. In this scenario, each permutation produced negative total net benefits regardless of technology type. The most profitable permutations are for the 10 MW step scenario at 0% retail load growth as observed in Figure 4(c), where each technology produced positive total net benefits. Zinc air technology produced the most sizable benefit. Figure 4(d) shows the results for a 10MW step scenario with a 2% load growth rate. With the exception of zinc air, which was only marginally profitable, each battery type produced a negative total net benefit.

Figure 4: Net Benefits for Use Case 1 – Substantial Energy



In analyzing the different battery technologies, the two main types that showed the greatest promise were lithium ion and zinc air. Figure 5 and Table 3 illustrate the net stacked benefits from a lithium ion battery selection within the ESCT for Use Case 1 in substantial energy deployments. Lithium ion is a well-established battery technology that could feasibly support a 2 or 10 MW deployment with acceptable technology risk. The other battery technology that showed promise was zinc air (see results in Figure 6 and Table 4). Zinc air is not as established as other technologies but is advertised to be cheaper, and projects are underway at utilities such as Pacific Gas and Electric in the power and energy ranges considered here [9].

Figure 5: Computed Lithium Ion Net Stacked Benefits – Substantial Energy

Table 3: Lithium Ion Stacked and Net Stacked Benefits Table – Substantial Energy

Project Outcome	Scenario			
	2 MW 0%	2 MW 2%	10 MW 0%	10 MW 2%
Gross Benefits				
Total	**$3,293,800**	**$3,467,900**	**$16,023,900**	**$17,765,700**
Deferred Transmission Investments	$2,945,300	$2,945,300	$15,501,300	15,501,300
Reduced Electricity Cost	$337,400	$506,100	$506,100	2,193,100
Ancillary Services	$11,100	$16,500	$16,500	71,800
Cost of Deployment, Total	**$3,019,500**	**$4,437,000**	**$5,020,600**	**$19,194,600**
Net Benefits				
Total	**$274,300**	**$(969,100)**	**$11,003,300**	**$(1,428,900)**
Deferred Transmission Investments	$245,278	$(823,060)	$10,644,441	$(1,246,774)
Reduced Electricity Cost	$28,098	$(141,429)	$347,529	$(176,392)
Ancillary Services	$ 924	$(4,611)	$11,330	$(5,775)

Figure 6: Computed Zinc Air Net Stacked Benefits – Substantial Energy

Table 4: Zinc Air Stacked and Net Stacked Benefits Table – Substantial Energy

Project Outcome	Scenario			
	2 MW 0%	2 MW 2%	10 MW 0%	10 MW 2%
Gross Benefits				
Total	**$4,677,400**	**$5,325,100**	**$22,991,300**	**$26,662,400**
Deferred Transmission Investments	$4,245,300	$4,245,300	$22,343,200	$22,343,200
Reduced Electricity Cost	$415,900	$1,039,500	$623,700	$4,158,300
Ancillary Services	$16,200	$40,600	$24,400	$162,400
Cost of Deployment, Total	**$2,771,900**	**$6,709,100**	**$4,549,300**	**$26,860,000**
Net Benefits				
Total	**$1,905,500**	**$(1,384,000)**	**$18,442,000**	**$(197,600)**
Deferred Transmission Investments	$1,729,469	$(1,103,359)	$17,922,140	$(165,590)
Reduced Electricity Cost	$169,431	$(270,167)	$500,288	$(30,818)
Ancillary Services	$6,600	$(10,552)	$19,572	$(1,204)

Minimal Energy Scenario. In comparison to substantial energy capacity, permutations at minimal energy capacity produced more favorable benefit levels, as expected. As seen from the results, this scenario is an optimistic one where a less costly smaller-energy storage unit defers essentially the same (significant) transmission investment considered in the substantial energy case. Regardless of technology type, step load, or load growth, each permutation exhibited positive net benefits. Figure 7(a) shows the results of the 2 MW step load, 0% load growth scenario, where net benefits range from approximately $1.6 million to $3.6 million. Zinc bromide produces the smallest benefit, while zinc air produces the largest net benefit. With the exception of zinc bromide and lithium ion chemistries, all battery types produce net benefits, ranging from approximately $2.8 million to $3.6 million. Figure 7(b) shows the net benefits of permutations in the 2 MW/2% load growth scenario. The results range from approximately $0.9 million (lead/advanced lead acid batteries) to $2.8 million (zinc air battery). As seen in Figure 7(c), net benefits range from approximately $13 million (zinc bromide) to $21 million (zinc air) in the 10 MW step load/0% load growth scenario. With the exception of zinc bromide and lithium ion chemistries, all battery types range from $19.1 million to $21 million in net benefits for this scenario. Lastly, net benefits for the 10 MW/2% load growth scenario are displayed in Figure 7(d). These benefits range from $7.4 million (zinc bromide) to $20.7 million (vanadium redox).

Figure 7: Net Benefits for Use Case 1 – Minimal Energy

Figure 8 and Table 5 illustrate the net stacked benefits from a lithium ion battery selection within the ESCT for Use Case 1 in the minimal energy deployments, while Figure 9 and Table 6 show the results of a zinc air deployment.

Figure 8: Illustration of Lithium Ion Net Stacked Benefits – Minimal Energy

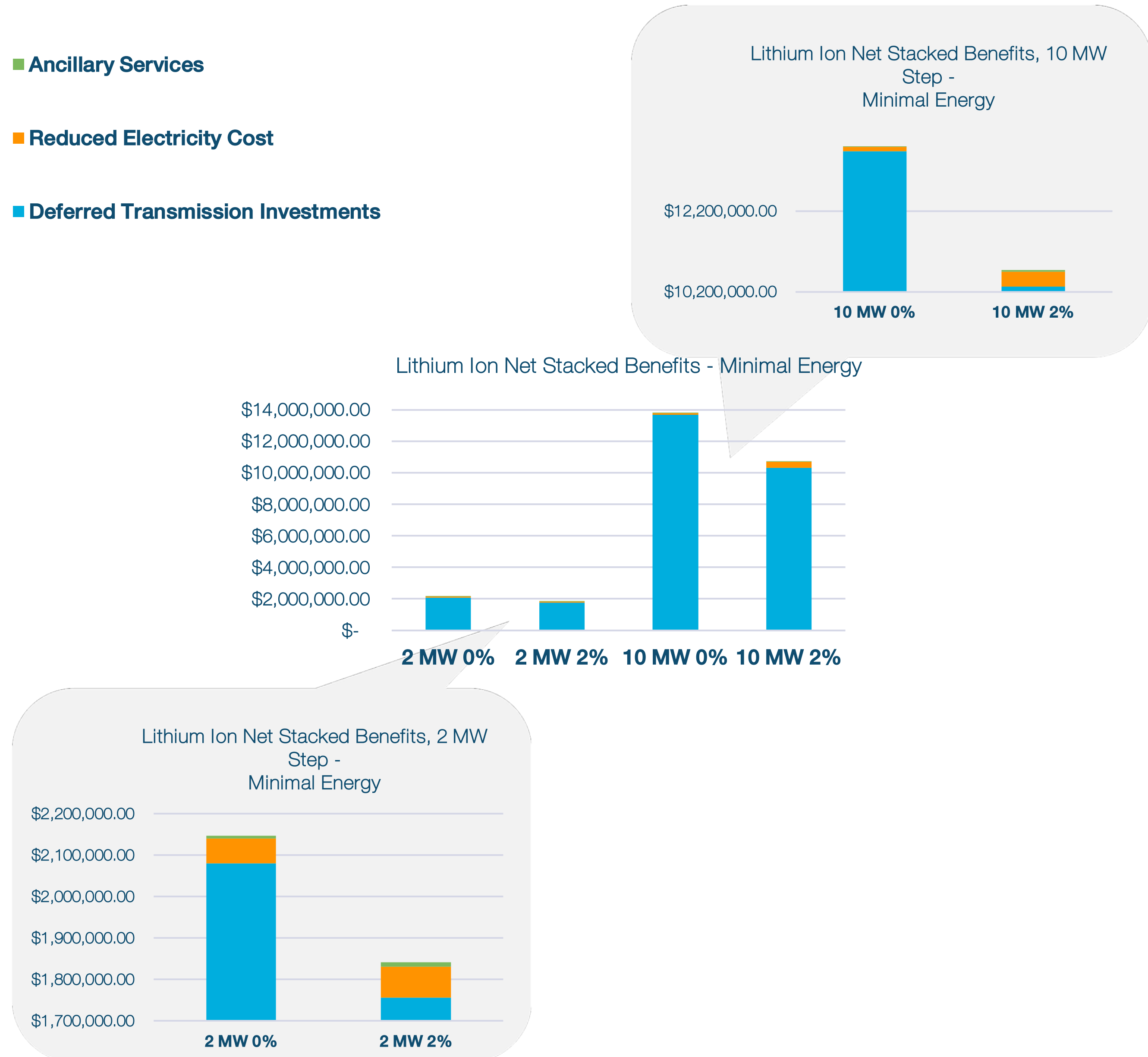


Table 5: Lithium Ion Stacked and Net Stacked Benefits Table – Minimal Energy

Project Outcome	Scenario			
	2 MW 0%	2 MW 2%	10 MW 0%	10 MW 2%
Gross Benefits				
Total	**$3,040,600**	**$3,088,400**	**$15,644,400**	**$16,121,400**
Deferred Transmission Investments	$2,945,300	$2,945,300	$15,501,300	$15,501,300
Reduced Electricity Cost	$84,200	$126,600	$126,600	$548,300
Ancillary Services	$11,100	$ 16,500	$16,500	$71,800
Cost of Deployment, Total	**$893,300**	**$1,247,700**	**$1,831,400**	**$ 5,374,900**
Net Benefits				
Total	**$2,147,300**	**$1,840,700**	**$13,813,000**	**$10,746,500**
Deferred Transmission Investments	$2,079,998	$1,755,412	$13,686,652	$10,333,142
Reduced Electricity Cost	$59,463	$75,454	$111,780	$365,496
Ancillary Services	$ 7,839	$9,834	$14,568	$47,862

Figure 9: Illustration of Zinc Air Net Stacked Benefits – Minimal Energy

Table 6: Zinc Air Stacked and Net Stacked Benefits Table – Minimal Energy

Project Outcome	Scenario			
	2 MW 0%	2 MW 2%	10 MW 0%	10 MW 2%
Gross Benefits				
Total	**$4,365,600**	**$4,545,700**	**$22,523,500**	**$23,544,800**
Deferred Transmission Investments	$4,245,300	$4,245,300	$22,343,200	$22,343,200
Reduced Electricity Cost	$104,100	$259,800	$155,900	$1,039,500
Ancillary Services	$16,200	$40,600	$24,400	$162,400
Cost of Deployment, Total	**$803,400**	**$1,787,600**	**$1,596,400**	**$7,174,100**
Net Benefits				
Total	**$3,562,200**	**$2,758,100**	**$20,927,100**	**$16,370,700**
Deferred Transmission Investments	$3,464,039	$2,575,833	$20,759,579	$15,535,227
Reduced Electricity Cost	$84,943	$157,633	$144,850	$722,764
Ancillary Services	$13,219	$24,634	$22,671	$112,917

5. Recommendations

The results from Use Case 1, both technical and economical, show that energy storage for this type of application in the Southeast has the potential to be attractive to utilities. Battery technologies such as lithium ion and zinc air show positive net benefits, which could increase as battery costs continue to trend downward. Lithium ion is a well-established technology that has been deployed in utility applications. Zinc air is a technology that is gaining interest at the utility scale due to its cheaper costs, long life, and recently reported improvements in recharge limitations.

It is important to note that when examining the results between the substantial-energy and minimal-energy scenarios, the main benefit of transmission capital deferral does not change. Therefore, it is recommended that utilities consider energy storage at the planning stage where capital deferral is a factor. In Use Case 1, capital deferral was found to be a powerful primary benefit because the required capacity and thus cost of the energy storage system is less sensitive to the size of the transmission system upgrade than to other factors such as hourly load profile and growth of the non-industrial load. In contrast, revenue from ancillary services is based on the capacity and other technical capabilities of the energy storage system and has been shown in previous studies often to be inadequate by itself to justify the investment in the energy storage system.

Figure S1: Grid-Tied Energy Storage in the Southeast

In 2004, a large industrial customer selected the Golden Triangle area of Mississippi to site a new economic development project [87]. Severcorr (owned by Steel Dynamics Inc. since 2014), an industrial steel mill shown above, was built near a 500-kV TVA substation in West Point, Mississippi. An upgrade of existing transmission lines and a few miles of new transmission lines were needed to supply the new industrial load [10]. Severcorr brought a minimum step increase of 6 MW [11], which is bounded by the 2 and 10 MW project deployments assumed in the Use Case 1 analysis.

B. Use Case 2: Firming Utility-Scale Solar Power at High Penetration Levels

1. General Narrative

Given the current growth of solar power generation in Georgia and North Carolina, it may be necessary to "firm up" solar generation in both states by means of energy storage. This process would involve storing excess solar-generated energy for later use to avoid potential curtailment. Unlike wind energy, solar energy is generated during the day when energy use is higher and peak periods occur, often meaning solar energy is consumed at the time of generation. There are two salient justifications to "firm" solar energy. The first is the transient variability of solar generation due to clouds. This issue is common with solar generation in the Southeast. The second is the longer timescale of the daily energy demand cycle that is widely named the "duck curve." The duck curve gets its name from the shape of the apparent load-versus-time curve. The first identifiable departure from the normal peak at midday, as seen by the conventional dispatchable generation assets, is a flattening of the apparent load curve by large amounts of distributed generation in the form of solar (the "back of the duck"). Later in the day, there is a rapid increase in the load seen by the dispatchable generation when the solar generation begins to tail off in the afternoon (the "neck of the duck"). The use of energy storage in either situation would be an alternative to the conventional solution that involves firming up solar with conventional generation (e.g., natural gas-generated energy) held in reserve by the system operator.

Two aspects are important to consider in regard to the proposed Use Case 2: (1) the amount of variable generation (i.e., solar and wind generation) that exists in Georgia (voluntarily) and North Carolina (mandated) and (2) the motivation for solar generation in the states.

The use of energy storage as a means to firm up solar generation is contingent upon having enough solar energy to require excess purchases of spinning reserves to firm it. As it stands, Georgia likely does not *currently* have enough solar energy as a whole to necessitate the need of energy storage, while North Carolina is closer to needing energy storage. However, consideration should be given to the concentration of solar facilities. If solar generation is dense in a particular area relative to the conventional generation produced and used there, the proposed use case might be feasible, especially for correcting fast transients. Multiple reports speak to the feasibility of implementing energy storage based on the amount of variable generation that exists in the grid, with respect to curtailment of renewable generation. NREL's Renewable Electricity Futures Study found that once variable generation reaches 50%, the use of energy storage and flexibility measures becomes necessary [10]. In regard to curtailment of renewable generation, General Electric's Western Wind and Solar Integration study suggests that the grid could realistically handle 23% (20% from wind, 3% from solar) variable generation without waste [11]. Furthermore, 35% (30% from wind, 5% from solar) could be handled without curtailment assuming that flexibility measures were implemented.

Given the growth rate of solar energy in Georgia and North Carolina, we should not rule out the potential need for energy storage in the future. The amount of solar generation in Georgia has been rapidly increasing. According to the Solar Energy Industries Association, Georgia has 1,432 MW of solar capacity, making it the 8th highest-ranking state on this metric [12]. A total of 1,023 MW of solar capacity was installed in 2016 alone. Part of this growth comes from Georgia Power's programs aimed at utilizing solar power and renewable energy in general. Georgia Power's Advanced Solar Initiative (ASI) is an effort to "spur economic growth within the solar community in GA" [13]. The ASI's initial goal was to procure 210 MW of solar capacity through the purchase of distributed solar generation from costumers and utility-scale programs. Furthermore, Georgia Power's 2016 Integrated Resource Plan calls for an additional 1,200 MW of renewable energy to be obtained as part of another of the utility's programs, the Renewable Energy Development Initiative [14]. Since only one-quarter of this energy can consist of wind power, a sizable amount of the energy will likely come from solar generation. Of the 1,200 MW, 1,050 MW will be acquired through two separate requests for proposals (RFPs) during the 2018-2019 and 2020-2021 periods, while distributed generation will make up the remaining 150 MW. In this regard, Georgia Power is currently able to provide solar assets to customers who can purchase the power, according to a long-term power purchase agreement (PPA) as a result of the Solar Power Free-Market Financing Act (2015). By having solar panels installed, customers can benefit from the Solar Investment Tax Credit—available to those who have solar assets installed or have commenced construction of said assets by the end of 2021—with less risk than purchasing their own solar generation assets. Another factor contributing to the growth of solar generation in Georgia is the Green Power Electric Membership Corporation's (EMC) policy of providing solar energy to other EMCs in the state. Green Power, consisting of 38 of the 41 EMCs in Georgia, makes efforts to find and negotiate PPAs with providers of renewable energy across the state [15]. Depending on the specific EMC, customers choosing to use solar may pay a premium, while other EMCs might incorporate the cost of the renewables into their wholesale energy in a situation where all customers receive the benefit of renewable energy. Unlike Georgia Power, Green Power EMC sells solar energy to customers but does not install solar assets on customers' property.

While Georgia Power's solar installations were voluntary, most of North Carolina's solar installations came as a result of state mandates. North Carolina is second in the nation in terms of total installed solar power capacity, so it is only natural and extremely consequential that the impacts of intermittent solar power generation on the grid are fully understood.

Throughout the Southeast, the emergence of needs for firming up solar resources are likely to result from market-driven growth in solar demand as opposed to the creation of Renewable Energy Portfolio Standards (REPS). North Carolina is currently the only southern state with a mandatory REPS [16], and even there, policies have recently been enacted that should render the solar industry more market-driven, such as competitive bidding for utility-scale solar units and a solar leasing program [17]. In this new North Carolina policy, energy storage is given an increased priority.

As a result of the research reported in this narrative, we conclude that Use Case 2 is relevant to the Southeast, and, more specifically, should be applied to a region approximated by an area with a large, concentrated growth of solar energy.

2. Power System Analysis

Battery technologies are considered in Use Case 2 given the power and energy levels required by the scenario. The following types of batteries were examined: lithium ion, lead acid, advanced lead acid, iron chromium, sodium sulphur, vanadium redox, zinc air, and zinc bromide. Table 7 represents some of the inputs into the ESCT. The inputs were obtained from the Electricity Storage Handbook [5] as well as Lazard's Levelized Cost of Storage Version 2.0 [6]. Based on quotes from vendors provided in the handbook [5], it is assumed that the cycle life of all battery types is sufficient to cycle once per day for the lifetime of the unit. It is assumed that the storage devices will cycle one full time per day. Because the ESCT is a high-level analysis tool, many of the details of the energy storage plant's internal operating characteristics, such as depth of discharge, ramp rates, etc., are neither needed nor considered in this analysis.

Table 7: Characteristics of Technologies for Use Case 2

Type	Round-Trip Efficiency	Total Installed Cost ($/kWh)	O&M Cost ($/kWh)
Lithium Ion	90%	440	5
Lead Acid	90%	593	12
Advanced Lead Acid	90%	593	12
Iron Chromium	75%	544	16
Sodium Sulphur	75%	468	7
Vanadium Redox	75%	487	12
Zinc Air	80%	261	7
Zinc Bromide	60%	699	21

The amount of energy storage needed for this particular use case was determined by the use of MSU software tools. The tools were utilized in order to identify a potential site for energy storage. Continued solar penetration at the scale of that in the Duke and Georgia Power areas are bound to cause problems in the high-voltage transmission system. In this analysis, it is assumed that an area of the southeastern power system has a somewhat higher penetration of solar surrounding existing fossil fuel plants. Upon sudden removal of a portion of the local generation, the Corrective Actions Tool identified a potential for cascading failure. Upon addition of a 10 MW energy storage unit, that particular cascade was avoided. Therefore, with the growing solar penetration in the region, there are certain to be instabilities introduced by this continued integration that could be resolved utilizing energy storage.

The energy storage deployment in this case yields benefits mostly in the form of renewables capacity firming and renewable energy time-shift. Since the ESCT tool is a high-level analysis tool, several assumptions were made about the operation of the unit:

- **The unit can cycle one time per day.**
- **The amount of generation deferred is equal to the size of the storage unit.**
- **The technology and costs of the deferred generation are that of newer peaking plants.**
- **The unit can profitably fully cycle once per day.**

3. Economic Analysis

Using the ESCT to estimate the costs and benefits of energy storage deployments for Use Case 2 required the specification of values for several ESCT inputs representing economic and market conditions. These inputs fall into five broad categories: general economic inputs; energy storage cost inputs; capacity-firming inputs; generation cost inputs; and emissions-related inputs.

General economic inputs. The general economic inputs include the average inflation rate and the discount rate. The inflation rate value used in the analysis is equal to the compound annual growth rate in the Consumer Price Index for the South Urban Area over the 2010-2016 period. The discount rate value utilized is the estimated after-tax weighted cost of capital reported in the DOE/EPRI Electricity Storage Handbook [5].

Energy storage cost inputs. Energy storage cost inputs include deployment's total installed cost, average yearly operating and maintenance (O&M) cost, fixed-charge rate, and expected decommissioning and disposal cost. The values used for total installed cost and O&M cost were derived from Lazard [6]. This up-to-date source provides marginal-installed and O&M cost figures (in $/kWh) for several different types of energy storage technology. To obtain estimates of the total installed cost and average yearly O&M cost of each hypothetical energy storage deployment, the energy storage capacity of the respective device was multiplied by the lower-bound installed cost figure and lower-bound O&M cost figure provided by Lazard for that technology. Lower-bound costs were assumed based on the tendency for the expenses associated with battery technology to fall over time. The fixed-charge rate used in the analysis is equal to the midpoint of the range of fixed-charge rates typically paid by investor-owned utilities reported by Shaalan [7]. Values for energy storage decommissioning/disposal costs were calculated with an estimate provided by Battery Solutions of the price of recycling a lithium ion battery (in $/pound). One decommissioning cost value was utilized throughout the analysis. Because, in the authors' opinion, distinguishing decommissioning costs by technology would have required speculation, the decision was made to not allow decommissioning costs to distinguish technologies in the economic assessment.

Capacity-firming inputs. The key economically related capacity-firming input is the price of the conventional capacity that would need to be added to the electrical system in the absence of solar firming. The value used for this input is an estimate of the annualized cost of establishing and operating a combined-cycle natural gas plant. This estimate was calculated from installed and fixed O&M cost figures for combined-cycle generation provided by the U.S. Energy Information Administration [18].

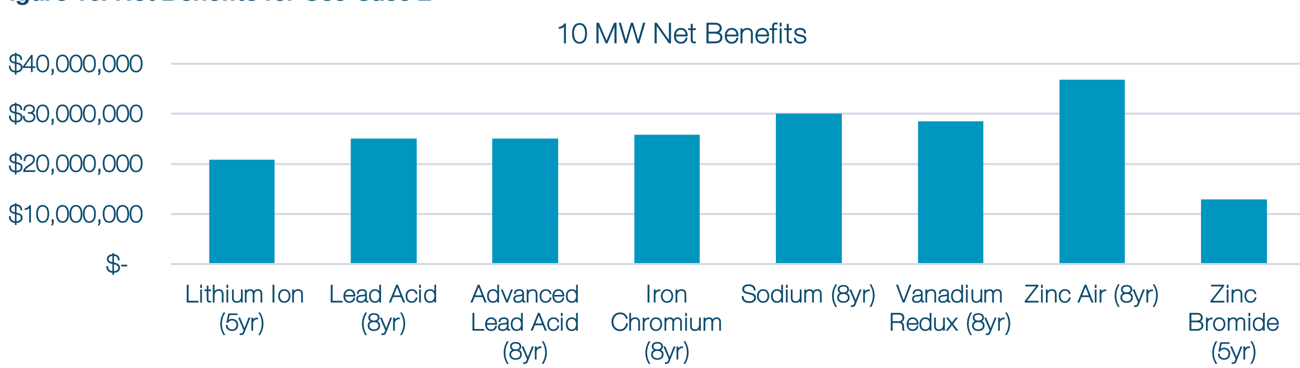
Generation cost inputs. The generation cost inputs include the average variable peak generation cost and average variable renewable generation cost. Recent U.S. Energy Information Administration estimates of the average variable O&M cost of conventional combined-cycle natural gas generation and solar generation were used to measure these quantities, respectively [8].

Emissions-related inputs. The emissions-related inputs include the emissions factors and value of sulfur-oxides (SOx) and nitrogen-oxides (NOx). These two gas emission classes were considered in the analysis because they possess tangible value owing to their inclusion in emissions-trading systems. CO_2 emissions can also be examined with the ESCT but were not considered because CO_2 is not subject to a trading system and thus cannot be readily assigned a monetary value. ESCT default inputs were relied on in determining emissions factors. The figures used in the analysis to represent the value of SOx and NOx are based on allowance trading price quotes for these gases supplied by Evolution Markets.

4. Results

Figure 10 shows the net benefits of different battery technologies when adding 10 MW of energy storage to "firm" solar and thus providing generation deferral. The results were all positive and ranged from ~$13 million to ~$36 million.

Figure 10: Net Benefits for Use Case 2



For the same reasons in Use Case 1, lithium ion and zinc air were analyzed further since those technologies show the greatest promise. Figure 11 and Table 8 illustrate the net stacked benefits from a lithium ion battery selection within the ESCT for Use Case 2. Figure 12 and Table 9 illustrate the net stacked benefits from a zinc air battery selection within the ESCT for Use Case 2.

Figure 11: Net Stacked Benefits for Use Case 2 – Lithium Ion

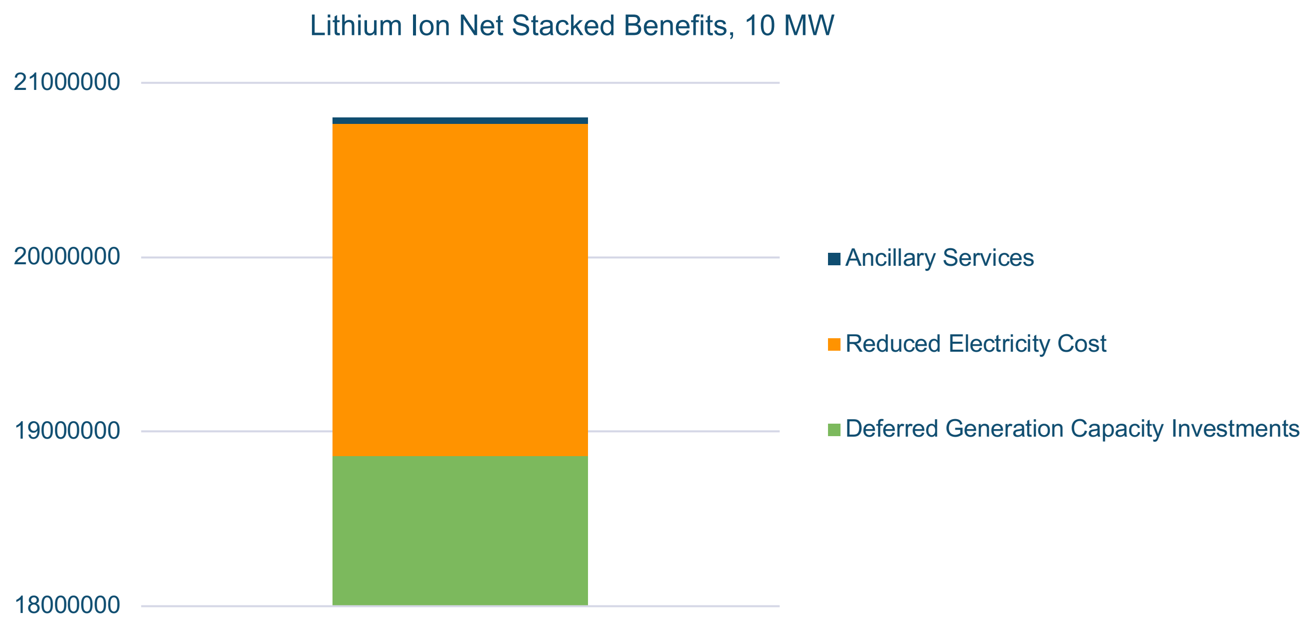


Table 8: Lithium Ion Stacked and Net Stacked Benefits – Use Case 2

Project Outcome	Value
Gross Benefits	
Total	**$31,927,500**
Deferred Generation Capacity Investments	$28,885,200
Reduced Electricity Cost	$2,909,900
Ancillary Services	$55,300
Cost of Deployment, Total	**$11,077,800**
Net Benefits	
Total	**$20,849,700**
Deferred Generation Capacity Investments	$18,862,979
Reduced Electricity Cost	$1,900,260
Ancillary Services	$36,113

Figure 12: Net Stacked Benefits for Use Case 2 – Zinc Air

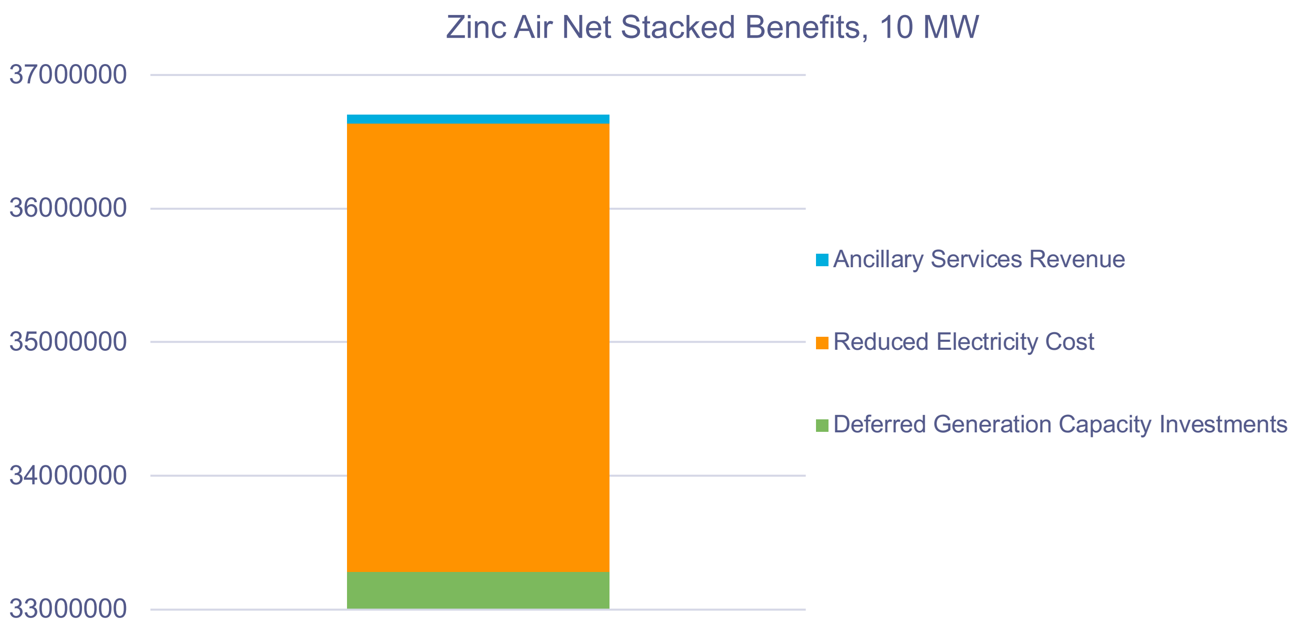


Table 9: Zinc Air Stacked and Net Stacked Benefits Table – Use Case 2

Project Outcome	Value
Gross Benefits	
Total	**$46,989,000**
Deferred Generation Capacity Investments	$42,511,600
Reduced Electricity Cost	$4,282,600
Ancillary Services	$81,400
Cost of Deployment, Total	**$10,199,300**
Net Benefits	
Total	**$36,789,700**
Deferred Generation Capacity Investments	$33,284,152
Reduced Electricity Cost	$3,353,031
Ancillary Services	$63,732

5. Recommendations

The results from Use Case 2, both technical and economical, show that energy storage for this type of application in the Southeast has the potential to be attractive to utilities in order to "firm" solar plants. Battery technologies such as lithium ion and zinc air show positive net benefits, which could increase as battery costs continue to trend downward. Lithium ion is a well-established technology that has been deployed in utility applications. Zinc air is a technology that is gaining interest at the utility scale due to its cheaper costs, long life, and recently reported improvements in recharge limitations.

Figure S2: Solar plus energy storage project in North Carolina

An electric cooperative in North Carolina is having solar plus battery storage projects installed by Cypress Creek Renewables [89]. According to an article from the Charlotte Business Journal, "the co-op wanted firm solar power available for peak times." There will be 12 projects in all, totaling up to just less than 6 MW of solar and energy storage.

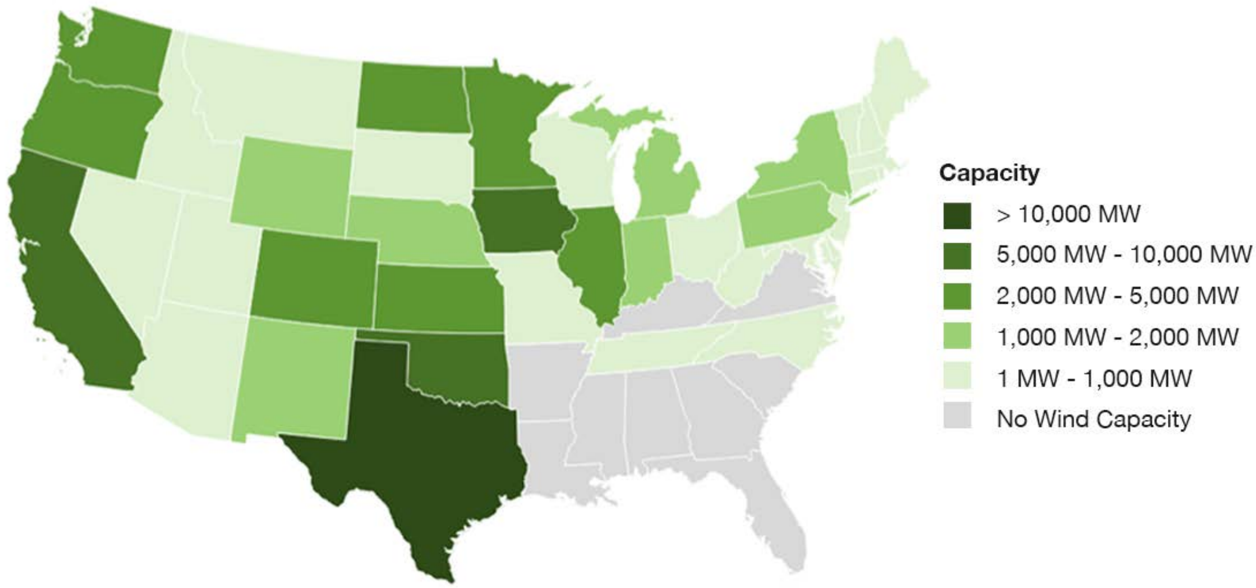
C. Use Case 3: Expanded Importation of Wind Energy from Western Sources

1. General Narrative

Utilities in the United States are using solar and wind energy as a source of energy production. With more than 81 GW of installed wind capacity, or roughly 8% of total power generation in the United States, there is great potential for this source to provide a substantial supply of energy, assuming energy storage resources are available in order to use this energy when it is demanded. Use Case 3 focuses on bulk energy storage at the levels of large traditional power plants, which will explain the substantial net benefits gained. Unlike conventional power generation, the power of renewable sources cannot be harvested on demand, and these sources' peak electricity generation typically coincides with off-peak energy demand, resulting in oversupply of energy during off-peak times and insufficient supply during peak hours.

In addition to the time shift in generation and peak demand, generation of renewable energy is favored in certain states and may not be present in other states. Figure 3 shows there is little to no wind generation capacity in the southeastern states; as a result, wind energy needs to be imported from other states.

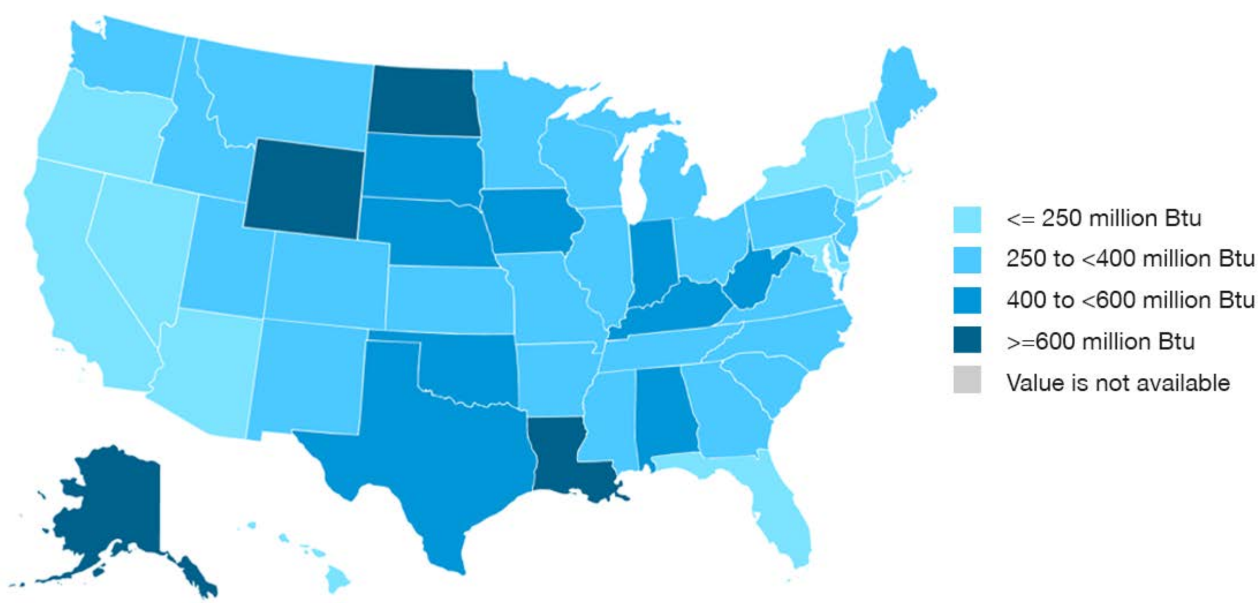
Figure 13: Wind Generation Capacity in the Lower 48 States (as of December 2016) [19]



With more than 20.2 gigawatts of wind generation capacity, Texas is the most prominent operator of wind energy in the United States [19], which makes it a primary source for exporting wind energy to neighboring southeastern states.

Energy demand is growing rapidly in some portions of the southeast. As shown in Figure 14, Louisiana has the highest total energy consumed per capita in the nation with 921 million Btu [20]. To meet this demand and overcome the congestion of the transmission lines with time-of-day overloads, either new localized energy generation and transmission infrastructure needs to be built, or renewable energy, specifically wind, needs to be imported from the western states and stored during off-peak hours.

Figure 14: Total Energy Consumed Per Capita (million Btu), 2014 [20]

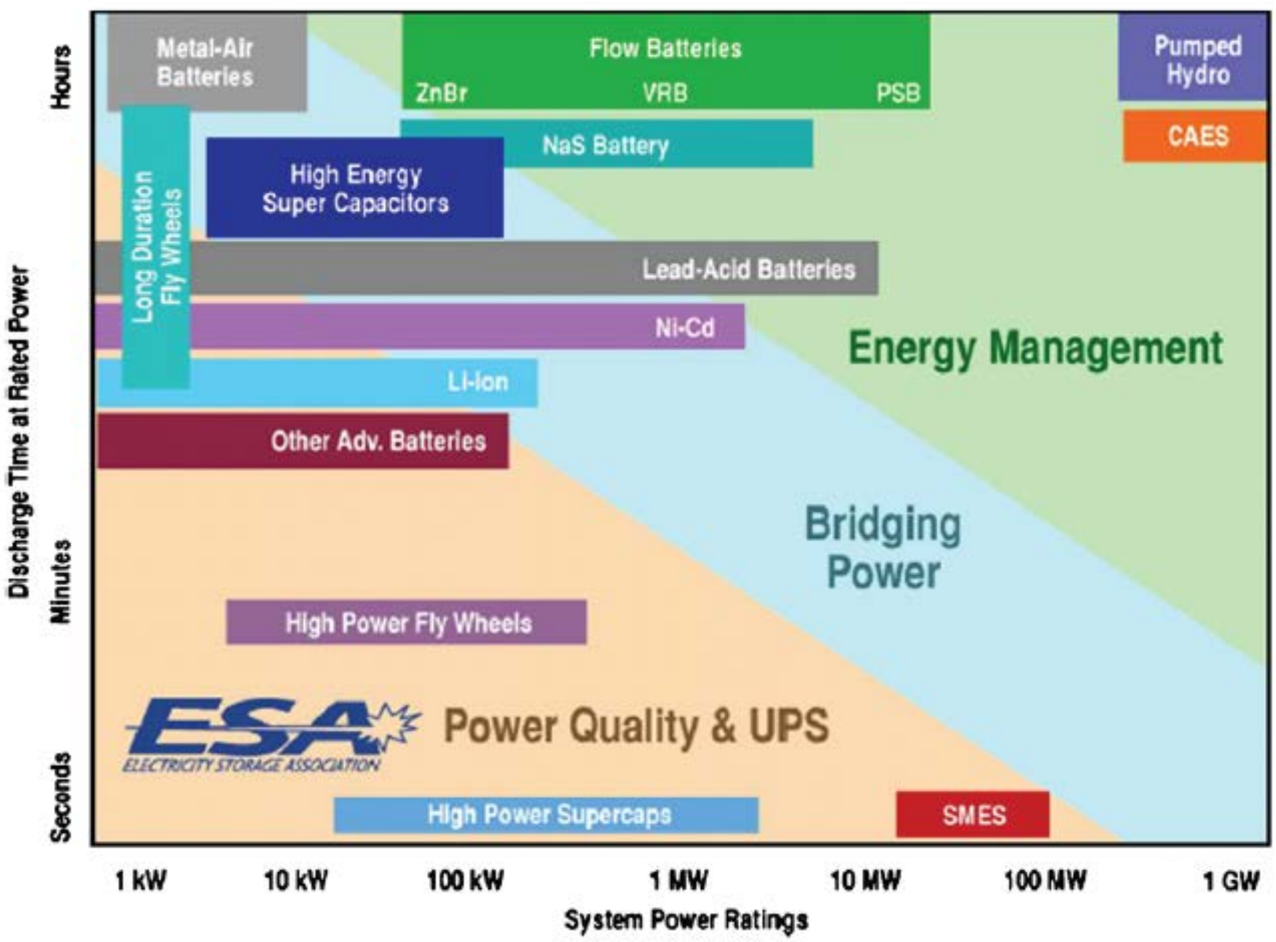


Storing excess energy generated during off-peak hours and later using it during peak energy-demand hours is an industry-recognized practice, though often limited by the capacity and time that it takes for the storage medium to go online and supply the energy back to the grid.

While lead acid and lithium ion batteries are feasible and cost-effective solutions for small-scale energy storage, they are not suitable for large utility-scale storage due to their limited ability to withstand high cycling rates and inadequate storage density.

Pumped hydro and compressed air energy storage (CAES) are the only two feasible methods of large-scale energy storage (more than 100 MW) [21] as shown in Figure 15. Application of these techniques, however, is limited by geological and geographical factors and require substantial infrastructure and capital investment.

Figure 15: Energy Storage Technology System Power Ratings Versus Discharge Time



Pumped Hydro

Pumped hydro storage (PHS) is a readily available storage system that uses existing hydroelectric generation infrastructure and the power of water to offer a high-capacity, highly concentrated energy storage solution, capable of providing hundreds of MWh or, in some instances, tens of GWh of storage capacity [22].

PHS involves pumping water from lower reservoirs to upper reservoirs during off-peak periods and subsequently allowing the water to return to low reservoirs when demand is high, generating electricity as it passes through the turbines. With acceptable efficiency of 65-80%, PHS is a feasible solution that is constrained by geographical limitations [22] and existence of hydroelectric plants.

Compressed Air Energy Storage

Compressed air energy storage (CAES)—another form of high-concentration, scalable, and high-capacity energy storage—pressurizes air to store energy during off-peak hours. When demand is high, the CAES unit reverses the storage process, allowing air to decompress and pass through turbines, thus feeding the grid in less than 15 minutes.

CAES units can be scaled to grid requirements, ranging from micro- to utility-scale storage options, and can provide electricity for short to medium periods [23] with 60% to 80% efficiency [21], depending on the type of CAES system implemented.

Unlike micro-CAES—which uses a series of above-ground or shallow underground pipes, cylinders, or storage tanks to hold the compressed air—utility-scale CAES requires a suitable underground trap that can contain the compressed air without significant loss or leakage (e.g., a salt dome, depleted oil or gas reservoir, or brine aquifer).

As a result, utility-scale CAES requires exploration for a suitable geologic setting and the drilling of one or more exploration wells into the target formation. In addition, rigorous studies need to be conducted to ascertain whether preparation of the site and storage of compressed air into the formation would lead to geomechanical risks, including unintentional induction of hydraulic fractures and reactivation of existing faults or fractures. Selection of a salt dome requires injection of fresh water into the formation to dissolve the salt and create a cavern, the byproduct of which is salt water, which requires surface treatment or subsequent injection into a salt water disposal (SWD) well.

With considerable service of availability of 90% and starting reliability of 99%, along with high specific energy density of 0.145 MWh/MCF and a long service lifetime of 20 to 40 years, CAES is a top candidate for energy storage.

Existing CAES Plants and Technologies

The first commercial CAES plant was built in Huntrof, Germany, in 1978. This plant was built on top of two cylindrical salt caverns at depths of 1,968 ft and 2,624 ft, and each cavern has a storage capacity of 5.29 MMCF with air pressures between 725 and 1015 psi. This plant can output 290 MW for two hours [24].

The second commercial CAES plant was built in 1991 in McIntosh, Alabama, over a salt cavern at a depth of 1,476-2460 ft, with a storage capacity of 19 MMCF and air pressures between 652 and 1100 psi. This plant uses a recuperator to conserve heat during compression of gas and later uses it to preheat the air before entering the turbines. This process results in a 25% reduction in fuel consumption compared to the Huntrof plant and enables the McIntosh plant to generate 110 MW for 26 hours [24].

Both of these plants, as well as many plants planned for future implementation, use diabatic processes where air compression is separated from natural gas compression. Here, the air that was compressed during off-peak hours is fed into the turbine. This process frees up turbine capacity considerably, enabling the CAES turbine to generate three times the output of a conventional natural gas turbine for the same amount of fuel and much fewer CO_2 emissions [25]. In addition, use of a recuperator to capture the waste heat to warm the air can add another significant reduction in fuel consumption (as with the McIntosh plant).

The Huntrof and McIntosh plants both use single-shaft machines where the compression and generation units are attached to each other and do not allow for plant expansion as the demand or availability of excess energy grows. As such, a more favorable plant design should include separate units for compression and power generation [25].

Cost Estimates for a New CAES

In many instances, locating a CAES site, or drilling the exploration and storage wells into it, can result in a significant upfront cost to the project. Additionally, installation of compressors, intercoolers and aftercoolers, turbines, and recuperators can add significantly to the overall cost of the project.

A promising cost-reducing alternative to building a CAES site from scratch is repurposing an existing natural gas storage (NGS) system and converting it into a CAES system. Not only does this approach eliminate the exploration, geomechanical risk assessment, and drilling costs, it can also help with the infrastructure cost as well as the cost associated with compressors and inter/aftercoolers.

The present study compares the added benefits of converting NGS sites in the southeastern United States into CAES sites versus the conventional construction of new CAES sites at undeveloped locations. Preliminary results of this study suggest that repurposing NGS sites for CAES is a very cost-effective approach that can not only facilitate the importing of wind energy into the Southeast from western states but also help boost renewable energy production in the Southeast.

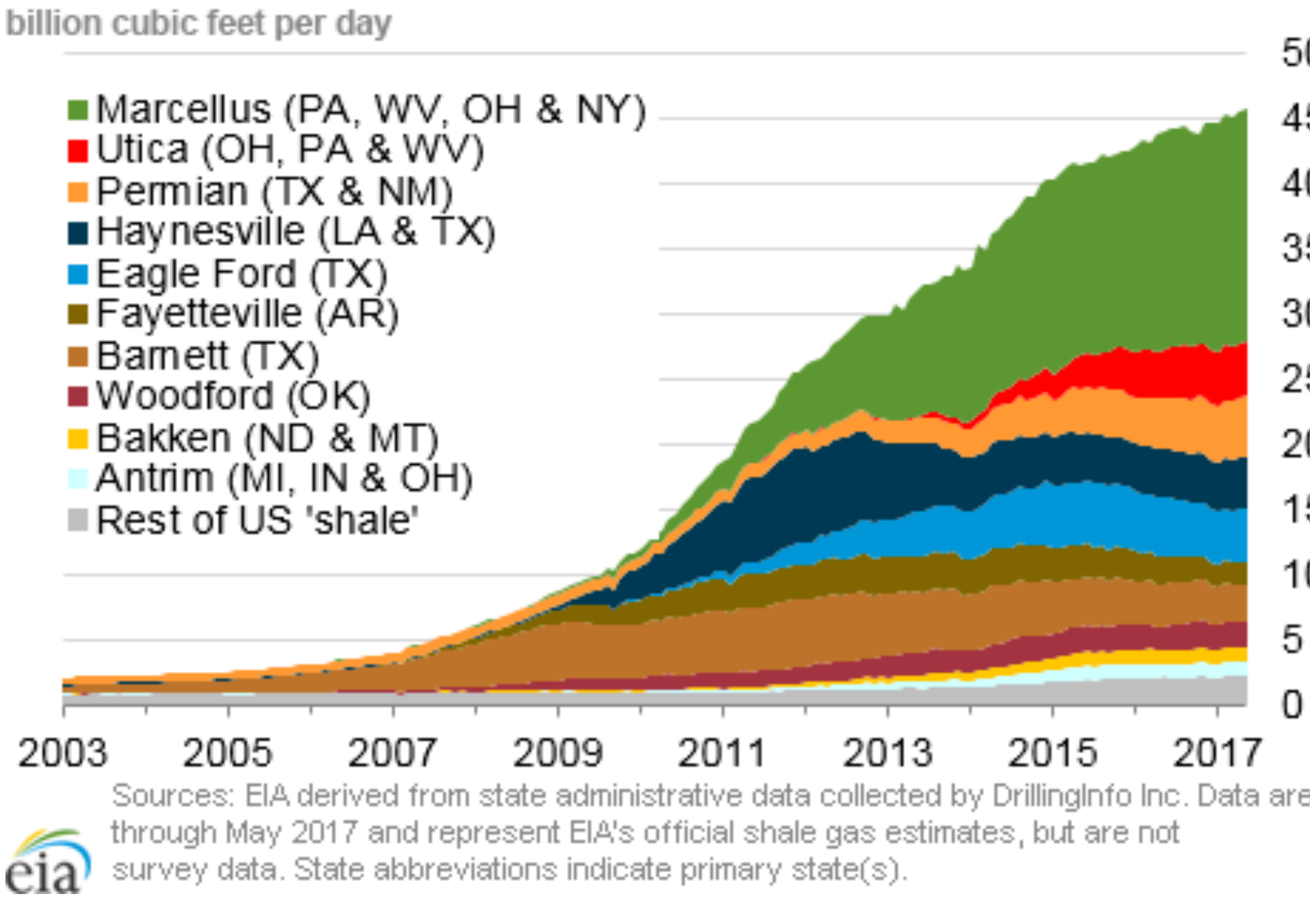
Underground Natural Gas Storage

The supply of natural gas usually exceeds demand during warm months but is often surpassed by demand during cold months. The storage of natural gas underground in salt caverns or depleted oil and gas fields is a conventional approach for overcoming shortages of natural gas. Natural gas is compressed and pumped into a reservoir at high pressures where it is stored during warm months and later pumped back and fed into the pipeline during cold months.

Historical Needs and Current Challenges

For decades, it was believed that shales, rocks with considerable porosity and hydrocarbon reserve, could not be put into production due to ultra-low permeability. As a result, conventional resources, such as sandstone reservoirs, were the main suppliers of oil and gas with declining reserves and loss of productivity. Recent advances in horizontal drilling, well completion, and multi-stage hydraulic fracturing techniques have turned otherwise unproductive shales into viable hydrocarbon sources. As shown in Figure 16, monthly dry shale gas production in the United States has increased significantly since 2007.

Figure 16: Monthly Dry Shale Gas Production in the United States



Unexpected growth in supply of unconventional oil and gas resources and geopolitical factors have contributed to drastic price reductions and a downturn in the oil and gas industry.

Before the most recent downturn, natural gas was traded as a high-value commodity with prices as high as $8.86/MMBTU, but its price has since dropped significantly to $2.52/MMBTU [26]. Such low prices can render NGS sites unprofitable, leaving operators with no choice but to repurpose or abandon sites.

Utilization of NGS Sites for CAES

When NGS is no longer economical, repurposing an NGS site for CAES purposes can be an enticing option that is not only economical but also bears several benefits for a CAES project.

A key component of a CAES site is the reservoir in which the compressed air is stored during off-peak hours and from which it is drawn during peak hours. Such a reservoir needs to be located through geological explorations and assessed through rigorous geomechanical studies to ensure that the reservoir would maintain its integrity during the charge and discharge processes.

In addition, a salt cavern needs to be washed by fresh water and the resulting brine disposed of, which is an expensive operation by itself.

Another major contributor to the cost of establishing a new CAES site is drilling of the injection wells. Regardless of the reservoir type, one or more injection wells must be drilled into the reservoir to allow for compressed air to be injected and retrieved from the reservoir.

An existing and operational NGS site utilizes a reservoir that contained hydrocarbons for millions of years but is now depleted or is based on a salt cavern that is already prepared and geomechanically examined for its safe injection limits. In addition, such a site would have one or more injection wells, as well as compressors, intercoolers, and aftercoolers, which themselves are major cost contributors.

An additional advantage of existing NGS sites is their proximity and access to natural gas pipelines, paved roads, surface facilities, and power transmission lines. However, NGS sites may not have gas turbines or heat recuperators, which are essential for CAES.

2. Power System Analysis

The Load Serving Tool (LST) script was utilized for Use Case 3. The power system model is similar in scale and quality to the model used by utilities in the Southeast. It is well known that Louisiana's electric energy demand is growing quickly due to many influences; therefore, it is very likely that wind imported from east Texas and Oklahoma will be well suited to serve new demands in Louisiana. New generation is being built to satisfy load growth in the region, and a CAES unit could defer a more costly generating facility.

The LST script was run with the seller set to existing NGS sites identified in northern Louisiana. The buyer was set to an area of southern Louisiana where load growth is highest. While several NGS candidates were identified, a superior candidate of interest was Cadeville Gas Storage in Ouachita Parish, especially since it is located near several natural gas plants that have direct access to high-voltage transmission. The LST script was run with N-1 contingencies serving load in southern Louisiana. The resulting analysis revealed that the particular generating site near Cadeville can supply more than 800 MW of additional power generation while respecting N-1 security constraints. Therefore, two cases were developed—a conservative approach and a more aggressive approach—to illustrate CAES capabilities and costs.

The first approach involves sizing the unit to minimize equipment and upgrade costs (i.e., compressors, coolers, exchangers, etc.), thus presuming it will be a "small" CAES deployment. Another approach is more aggressive and utilizes all 800 MW of additional capacity, thus presuming it will be a "large" CAES deployment. It was also decided to use another approach in the "medium" range between the small and large deployments. The key inputs into the ESCT are detailed in Table 10.

Table 10. Characteristics of CAES Technologies for Use Case 3

CAES Deployment	"Small"	"Medium"	"Large"
Power Capacity	180 MW	500 MW	800 MW
Energy Capacity (Daily Delivery)	1.62 GWh	4.5 GWh	7.2 GWh
Round-Trip Efficiency	78%	78%	78%
Lifetime of Unit	40 years	40 years	40 years
Total Installed Cost	$387/kW	$387/kW	$387/kW
Yearly O&M Cost[1]	$4.4/kW + $4.4/MWh +$15,840,000	4.4/kW + $4.4/MWh +$15,840,000	4.4/kW + $4.4/MWh +$15,840,000
Generation Capacity Deferred	180 MW	500 MW	800 MW
Capital Cost of Deferred Generation Capacity	$978,000/MW	$978,000/MW	$978,000/MW
Yearly Fixed O&M Costs of Deferred Generation Capacity	$11,000/MW	$11,000/MW	$11,000/MW
Renewable Energy Discharged for Time Shift	295.65 GWh/yr	821.25 GWh/yr	1,314 GWh/yr
Average Variable Peak Generation Costs	$59.66/MWh	59.66/MWh	$59.66/MWh
Average Variable Renewable Generation Costs	$25.90/MW	$25.90/MW	$25.90/MW

[1]The O&M cost specified for each CAES unit is equal to the sum of the deployment's estimated annual fixed variable cost ($4.4/kw); the estimated cost of the natural gas required for operating the CAES unit for a year ($4.4/MWh); and the estimated annual cost of leasing a 16.5 bcf natural gas storage site ($15,840,000), corresponding to the Cadeville Gas Storage facility in Ouachita Parish, Louisiana.

The limited availability of information led us to make the following assumptions about the unit's operation:

- **During the night, there are no transmission constraints caused by the addition of this CAES unit on the importation of wind from various sources.**
- **The unit will make one half cycle per day and will be devoted mainly to renewable energy time-shift.**
- **The unit will defer a necessary generation installation for the lifetime of the plant.**

3. Economic Analysis

Using the ESCT to estimate the costs and benefits of energy storage deployments for Use Case 3 required the specification of values for several ESCT inputs representing economic and market conditions. These inputs fall into five broad categories: general economic inputs; energy storage cost inputs; deferred generation cost inputs; generation cost inputs; and emissions-related inputs.

General economic inputs. The general economic inputs include the average inflation rate and the discount rate. The inflation rate value used in the analysis is equal to the compound annual growth rate in the Consumer Price Index for the South Urban Area over the 2010-2016 period. The discount rate value utilized is the estimated after-tax weighted cost of capital reported in the DOE/EPRI Electricity Storage Handbook [5].

Energy storage cost inputs. Energy storage cost inputs include the total installed cost of the deployment, the average yearly operating and maintenance (O&M) cost, the fixed-charge rate, and the expected decommissioning and disposal cost. The values used for total installed cost were derived from a cost estimate, calculated in a supplementary analysis, for converting a natural gas storage facility into a CAES unit. Several studies ([21] , [27]) have estimated the cost of a new CAES site to be between $400/kW and $800/kW. This cost includes the site preparation, drilling of injection wells, installment of compressors, intercoolers and aftercoolers, turbines, and recuperators. Given that repurposing an NGS site for CAES does not require identification and characterization of a storage site, drilling of new injection wells, or installment of compressors and inter/aftercoolers, the capital cost of CAES based on a reused NGS site should be considerably less. Indeed, it was estimated that converting an NGS to a modern CAES system capable of recuperating heat would cost around $387/kw. This figure forms the basis for the installed cost inputs. The O&M cost values were obtained by adding fixed and variable O&M cost figures for operating a below-ground CAES unit reported by EPRI [28] to the predicted cost of leasing a 16.5 bcf natural gas storage facility (corresponding to the Cadeville NGS operation) for a year. The fixed-charge rate used in the analysis is equal to the midpoint of the range of fixed-charge rates typically paid by investor-owned utilities reported by Shaalan [7]. Values for energy storage decommissioning/disposal costs were calculated with an estimate provided by Battery Solutions of the price of recycling a lithium ion battery (in $/pound). One decommissioning cost value was utilized throughout the analysis irrespective of CAES size. Because, in the authors' opinion, distinguishing decommissioning costs by storage device would have required speculation, the decision was made to not allow decommissioning costs to distinguish units in the economic assessment.

Deferred generation cost inputs. The deferred generation cost inputs include the capital cost of deferred generation capacity, the yearly O&M costs of deferred generation capacity, and the annual fixed-charge rate for generation capital investment. The values for deferred capital and O&M costs were computed from overnight capital cost and fixed O&M cost figures for natural gas combined-cycle plants provided in a U.S. Energy Information Administration report [18]. Once again, the fixed-charge rate is set equal to the midpoint of the range of fixed-charge rates normally paid by investor-owned utilities reported by Shaalan [7].

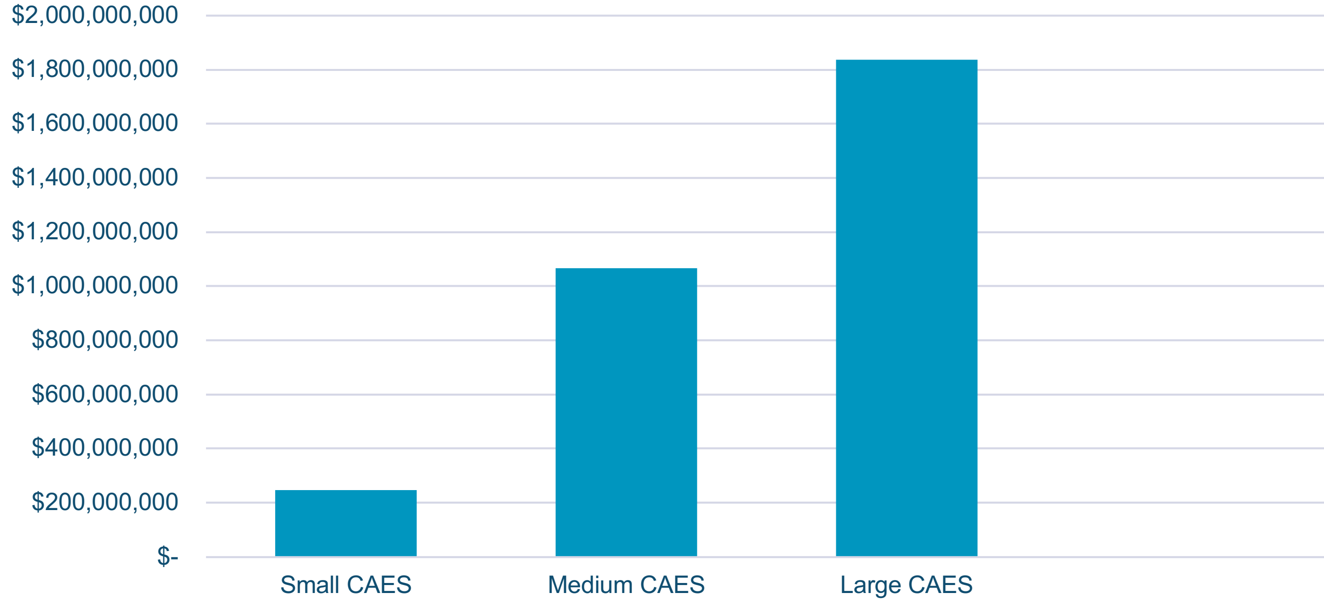
Generation cost inputs. The generation cost inputs include the average variable peak generation cost and average variable renewable generation cost. A recent U.S. Energy Information Administration estimate of the average variable O&M cost of conventional combined-cycle natural gas generation was used to measure the former [8]. The cost figure for renewable generation (i.e., wind power) came from the U.S. Department of Energy's 2015 Wind Technologies Market Report [29].

Emissions-related inputs. The emissions-related inputs include the emissions factors and value of sulfur-oxides (SOx) and nitrogen-oxides (NOx). These two gas emission classes were considered in the analysis because they possess tangible value owing to their inclusion in emissions trading systems. CO_2 emissions can also be examined with the ESCT but were not considered because CO_2 is not subject to a trading system and thus cannot be readily assigned a monetary value. ESCT default inputs were relied on in determining emissions factors. The figures used in the analysis to represent the value of SOx and NOx are based on allowance trading price quotes for these gases supplied by Evolution Markets.

4. Results

It was decided to evaluate three different CAES units: "small" (180 MW unit), "medium" (500 MW unit), and "large" (800 MW unit). Net benefits for all three units are shown in Figure 17. As stated previously, these results in billions of dollars are obtained because of the bulk storage levels involved. Due to the large benefit of generation deferral for bulk operation, the net benefits are all positive and large amounts, including $247 million for the small unit, $1.07 billion for the medium unit, and $1.84 billion for the large unit. These benefit levels compare favorably to the returns that would be achieved if the CAES units were constructed without any preexisting infrastructure (see Appendix B).

Figure 17: Net Benefits for Use Case 3 – Repurposed Natural Gas Storage into CAES



Stacked net benefits are shown in detail in Figures 18-20 and Tables 11-13.

Figure 18: Net Stacked Benefits for Use Case 3 – Small CAES

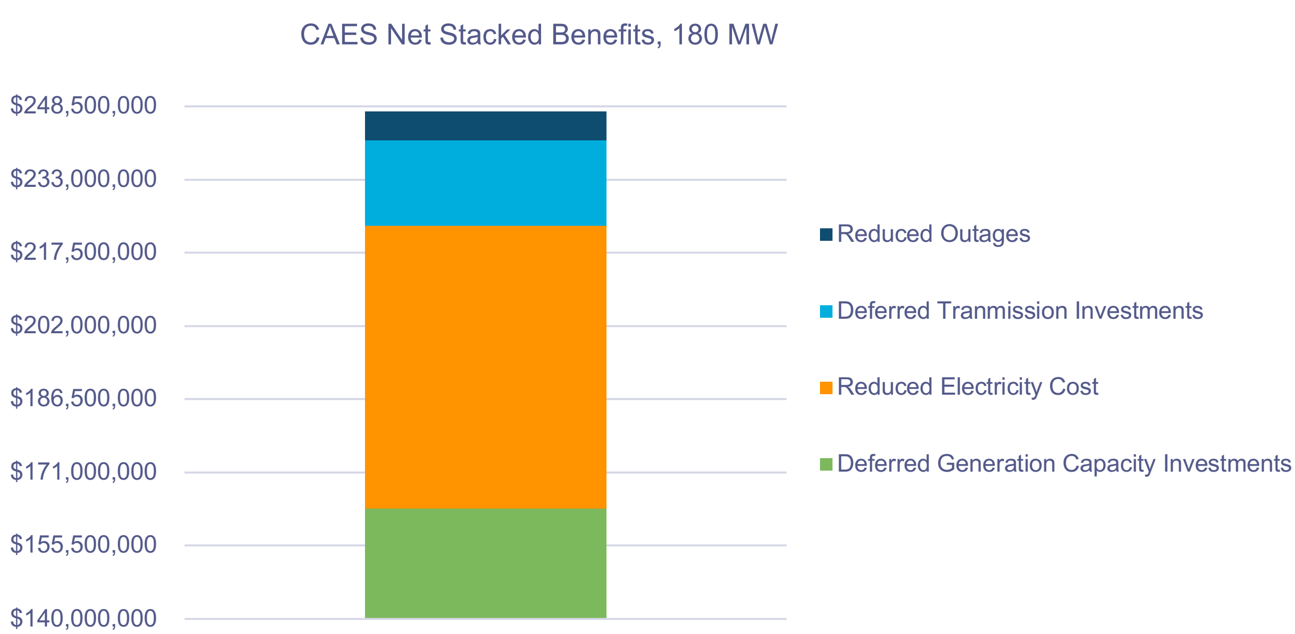


Table 11: Small CAES Stacked and Net Stacked Benefits – Use Case 3

Project Outcome	Value
Gross Benefits	
Total	**$647,617,300**
Deferred Generation Capacity Investments	$427,481,400
Reduced Electricity Cost	$156,743,700
Deferred Transmission Investments	$47,202,900
Reduced Outages	$15,998,200
Cost of Deployment, Total	**$400,152,700**
Net Benefits	
Total	**$247,464,600**
Deferred Generation Capacity Investments	163,347,263
Reduced Electricity Cost	59,894,195
Deferred Transmission Investments	18,036,959
Reduced Outages	6,113,160

Figure 19: Net Stacked Benefits for Use Case 3 – Medium CAES

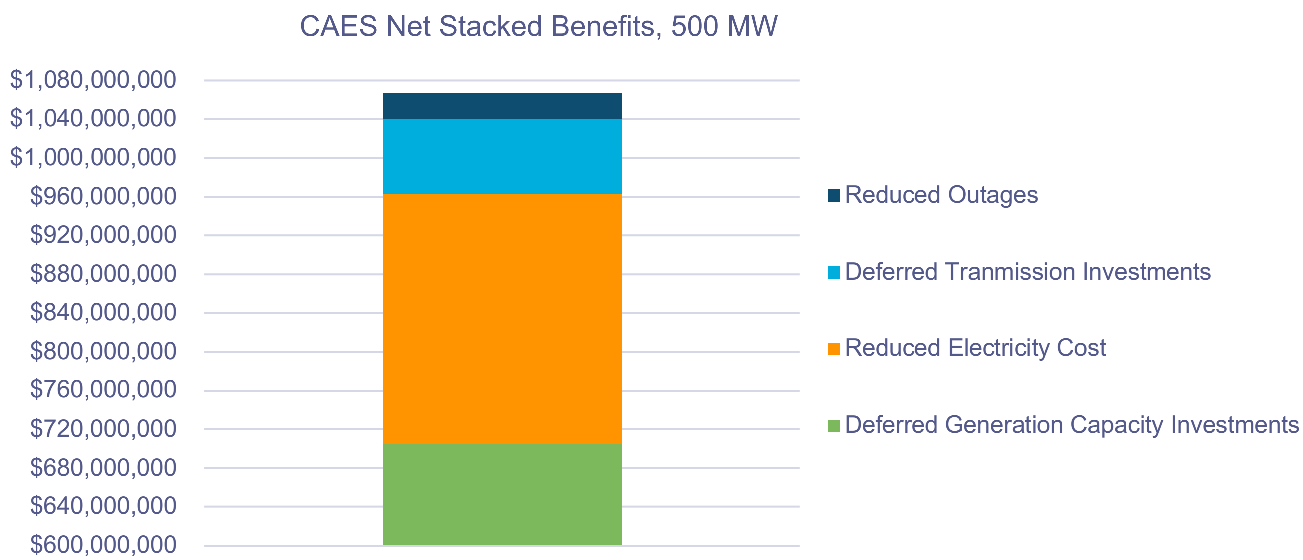


Table 12: Medium CAES Stacked and Net Stacked Benefits – Use Case 3

Project Outcome	Value
Gross Benefits	
Total	**$1,798,936,600**
Deferred Generation Capacity Investments	$1,187,448,800
Reduced Electricity Cost	$435,399,400
Deferred Transmission Investments	$131,118,200
Reduced Outages	$44,438,700
Cost of Deployment, Total	**$731,225,300**
Net Benefits	**$1,067,711,300**
Total	
Deferred Generation Capacity Investments	$704,778,869
Reduced Electricity Cost	$258,419,813
Deferred Transmission Investments	$77,821,744
Reduced Outages	$26,375,417

Figure 20: Net Stacked Benefits for Use Case 3 – Large CAES

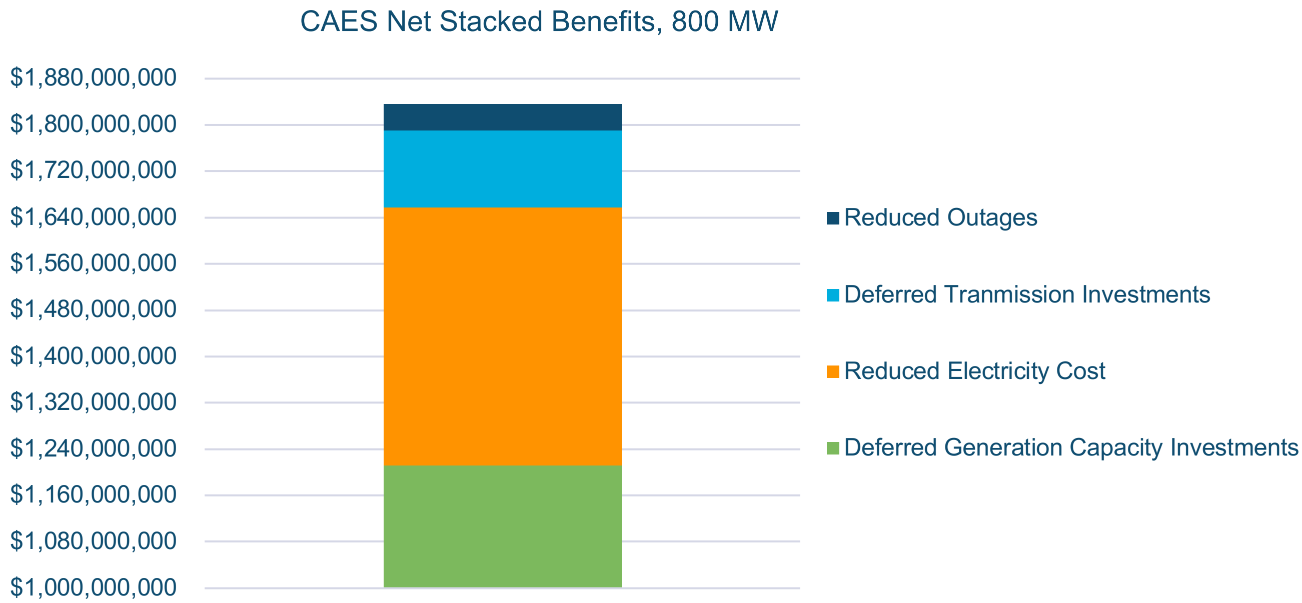


Table 13: Large CAES Stacked and Net Stacked Benefits – Use Case 3

Project Outcome	Value
Gross Benefits	
Total	**$2,878,299,200**
Deferred Generation Capacity Investments	$1,899,917,500
Reduced Electricity Cost	$696,639,200
Deferred Transmission Investments	$209,789,300
Reduced Outages	$71,102,600
Cost of Deployment, Total	**$1,041,606,000**
Net Benefits	
Total	**$1,836,693,200**
Deferred Generation Capacity Investments	$1,212,370,678
Reduced Electricity Cost	$444,537,691
Deferred Transmission Investments	$133,870,232
Reduced Outages	$45,371,816

5. Recommendations

CAES was determined to be a viable solution for utility-scale power storage in the Southeast. Abundance of depleted oil and gas fields, operational NGS facilities, relatively low market prices for natural gas, and improved year-round natural gas supply make the Southeast a prime candidate for importing renewable energy from neighboring states and economically storing it with CAES.

Existence of reliable storage reservoirs, compression stations, and injection wells and proximity to natural gas pipelines and power transmission lines make NGS facilities a very cost-effective candidate for conversion into CAES units. The geolocation of importable wind resources to the West of growing industrial loads in Louisiana and the location of many potential NGS sites near the loads make Use Case 3 an opportunity truly unique to the Southeast for the application of utility-scale compressed air energy storage.

Figure S3: Location of the Candidate NGS-to-CAES Site

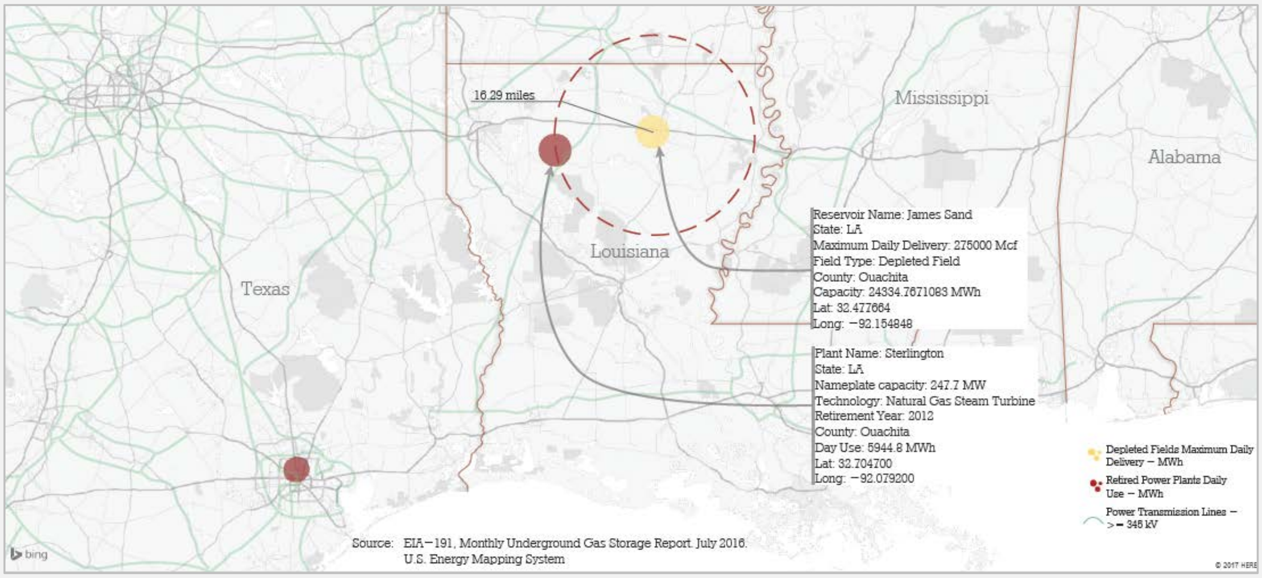


Figure S4: Compression Station at the Candidate NGS Site [90]

The NGS site of interest is a depleted natural gas storage facility located near Cadeville field near the city of Monroe in Ouachita Parish in Louisiana. This field is a part of Cardinal Gas Storage Partners LLC, which operates and manages natural gas storage facilities around the Gulf Coast region and was founded in 2008 as a subsidiary of Martin Midstream Partners L.P. Cadeville Gas Storage owns and utilizes this facility for receiving, injecting, storing, withdrawing, and delivering natural gas. It operates with interstate commerce, which is subject to Federal Energy Regulatory Commission jurisdiction. The facility is in close proximity to the Louisiana-Arkansas border and is also situated within a network of high-voltage transmission lines. The region that is supplied by this facility has a large number of other gas storage facilities, which in effect renders Cadeville unable to exert any market power and likely to suffer from economic disadvantage. Therefore, the site could serve as a viable facility for conversion to CAES.

In the case of conversion into a CAES facility, the system in the Cadeville facility could support more than 1.5 GW of generation (1783.94, according to the LST) in the power system model, which was used in this report. As this storage site provides a daily delivery level of 275,000 Mcf, the NGS reservoir could support up to 1.622 GW of output.

D. Use Case 4: Retirement of Fossil Fuel Generation

1. General Narrative

In today's society, many utilities are faced with decisions concerning older fossil-fuel plants, specifically coal-fired facilities. These aging, pollution-heavy facilities are under intense scrutiny for replacement with more efficient, environmentally friendly options. Duke Energy, for example, has a stated goal of providing electricity that is not only affordable and reliable but also produced on an environmentally sound basis. In line with this objective, Duke has been closing older coal-powered generation facilities and replacing them with more efficient clean coal and natural gas plants. By 2013, the company had decommissioned nine coal generation units across North and South Carolina [30]. As part of the same initiative, Duke is currently planning to retire a coal plant in Asheville, North Carolina, by 2020 and replace it with natural gas and solar generation units. In addition, Duke intends to install a minimum of five megawatts of energy storage at the plant over the next several years [31]. It is likely that ongoing political and social trends, along with the forecast of continuing low natural gas prices, will motivate Duke and other electric utilities to close down additional high-emission coal plants and replace them with a mix of new generation and storage technology. Use Case 4 considers whether an energy storage project could be deployed in such a situation to meet local and regional electricity demand while transmission system geographic realignments are planned, permitted, and constructed. It is anticipated that such a project could yield a substantial economic benefit through deferment of the construction of new generation to replace retired capacity and a consequent reduction in costly capital expenditures.

This use case will focus on an area in the Southeast where the power system is operating very close to capacity. It is assumed that fossil fuel plants in this area are being phased out for retirement purposes, and, as such, the local utility is at risk of losing the ability to supply its own load and would benefit from additional capacity. If the utility does not establish adequate generation/storage facilities to provide power to all customers during peak times with adequate reserves, it would be forced to make purchases from independent power producers (IPPs) to meet customer needs, which could lead to critical problems.

2. Power System Analysis

Given the focus of Use Case 4, each permutation assumes that the storage technology is deployed in the year 2022 by a utility within a regulated market of the SERC Reliability Corporation.

Battery technologies and an above-ground CAES unit are considered in Use Case 4 given the energy levels required by the scenario. The following types of batteries were examined: lithium ion, lead acid, advanced lead acid, iron chromium, sodium sulphur, vanadium redox, zinc air, and zinc bromide. Table 14 reports some of the values inputted into the ESCT. The inputs were obtained from the Electricity Storage Handbook [5]. Based on quotes from vendors provided in [5], it is assumed that the storage devices will cycle one full time per day for the lifetimes of the units. Because the ESCT is a high-level analysis tool, many of the details of the energy storage plant's internal operating characteristics, such as depth of discharge, ramp rates, etc., are neither needed nor considered in this analysis.

Table 14: Characteristics of Technologies for Use Case 4

Type	Round Trip Efficiency	Total Installed Cost	O&M Cost
Lithium Ion	90%	$440/kWh	$5/kWh
Lead Acid	90%	$593/kWh	$12/kWh
Advanced Lead Acid	90%	$593/kWh	$12/kWh
Iron Chromium	75%	$544/kWh	$16/kWh
Sodium Sulphur	75%	$468/kWh	$7/kWh
Vanadium Redox	75%	$487/kWh	$12/kWh
Zinc Air	80%	$261/kWh	$7/kWh
Zinc Bromide	60%	$699/kWh	$21/kWh
CAES	70%	$2144.3/kW	$4.4/kW + $4.4/MWh[1]

[1]The O&M cost specified for the CAES unit is equal to the sum of the deployment's estimated annual fixed variable cost ($4.4/kw) and the estimated cost of the natural gas required for operating the CAES unit for a year ($4.4/MWh).

In order to determine the amount of energy storage needed for this particular use case, MSU software tools were utilized to identify several sites that could be effected by coal plant retirement. Sudden retirement of plants due to administrative policy can cause unforeseen problems in the stability of the power grid. In MSU's system model, several older generating units were identified, and one unit of interest in this analysis caused extreme reliability issues, which could potentially lead to cascading failures within the region. For the purposes of the analysis, the storage units of this use case were simply placed where the relevant coal plants were located for maximum reuse of infrastructure and equipment; however, one could conceivably place several smaller units more strategically to obtain higher levels of reliability at a higher cost. The plant that caused problems that could potentially lead to catastrophic cascading failures was a very large steam plant (>700 MW) with several generating units. Therefore, based upon the power system analysis, it was determined to use a 50 MW energy storage unit to defer generation costs.

For this use case, the benefits yielded by the deployment stem primarily from generation deferral and the time-shifting of energy. The unit could also be used for reserve capacity. Since the ESCT tool is a high-level analysis tool, assumptions were made about the operation of the unit:

- **The unit can cycle one time per day.**
- **The amount of generation deferred is equal to the size of the storage unit.**
- **The technology and costs of the deferred generation are those of newer peaking plants.**
- **The unit can profitably fully cycle once per day.**

3. Economic Analysis

Using the ESCT to estimate the costs and benefits of energy storage deployments for Use Case 4 required the specification of values for several ESCT inputs representing economic and market conditions. These inputs fall into six broad categories: general economic inputs; energy storage cost inputs; deferred generation cost inputs; generation cost inputs; electric reserve supply capacity inputs; and emissions-related inputs.

General economic inputs. The general economic inputs include the average inflation rate and the discount rate. The inflation rate value used in the analysis is equal to the compound annual growth rate in the Consumer Price Index for the South Urban Area over the 2010-2016 period. The discount rate value utilized is the estimated after-tax weighted cost of capital reported in the DOE/EPRI Electricity Storage Handbook [5].

Energy storage cost inputs. Energy storage cost inputs include the deployment's total installed cost, average yearly operating and maintenance (O&M) cost, fixed-charge rate, and expected decommissioning and disposal cost. With the exception of the CAES deployment, the values used for total installed cost and O&M cost were derived from Lazard [6].This up-to-date source provides marginal installed and O&M cost figures (in $/kWh) for several different types of energy storage technology. To obtain estimates of the total installed cost and average yearly O&M cost of each hypothetical energy storage deployment, the energy storage capacity of the respective device was multiplied by the lower-bound installed cost figure and lower-bound O&M cost figure provided by Lazard for that technology. Lower-bound costs were assumed based on the tendency for the expenses associated with battery technology to fall over time. The installed and O&M cost values for the CAES deployment were calculated in a similar fashion from above-ground CAES cost data reported by EPRI [28]. The CAES O&M cost encompasses both the estimated fixed cost and the variable cost (i.e., the expense of purchasing natural gas) of CAES operation. As with other technologies, CAES cost inputs were based on lower-bound cost figures. The fixed-charge rate used in the analysis is equal to the midpoint of the range of fixed-charge rates typically paid by investor-owned utilities reported by Shaalan [7]. Values for energy storage decommissioning/disposal costs were calculated with an estimate provided by Battery Solutions of the price of recycling a lithium ion battery (in $/pound). One decommissioning cost value was utilized throughout the analysis, irrespective of technology. Because, in the authors' opinion, distinguishing decommissioning costs by technology would have required speculation, the decision was made to not allow decommissioning costs to distinguish technologies in the economic assessment.

Deferred generation cost inputs. The deferred generation cost inputs include the capital cost of deferred generation capacity, the yearly O&M costs of deferred generation capacity, and the annual fixed charge rate for generation capital investment. The values for deferred capital and O&M costs were computed from overnight capital cost and fixed O&M cost figures for natural gas combined-cycle plants provided in a U.S. Energy Information Administration report [18]. Once again, the fixed charge rate is set equal to the midpoint of the range of fixed-charge rates normally paid by investor-owned utilities reported by Shaalan [7].

Generation cost inputs. The generation cost inputs include the average variable peak generation cost and average variable off-peak generation cost. A recent U.S. Energy Information Administration estimate of the average variable O&M cost of conventional combined-cycle natural gas generation was used to measure the former, while the corresponding cost figure for conventional coal generation was used to measure the latter [8].

Electric reserve supply capacity inputs. The electric reserve supply capacity inputs include the marginal operating costs of conventional generation at partial and optimal loads. The value used for marginal operating costs at optimal load is based on a recent Energy Information Administration estimate of the average variable O&M cost (including fuel) of conventional combined-cycle natural gas electric generation [8]. The value used for marginal operating cost at partial load is the same value but multiplied by 1.01, which is the factor suggested by the ESCT User Guide.

Emissions-related inputs. The emissions-related inputs include the emissions factors and value of sulfur-oxides (SOx) and nitrogen-oxides (NOx). These two gas emission classes were considered in the analysis because they possess tangible value owing to their inclusion in emissions trading systems. CO_2 emissions can also be examined with the ESCT but were not considered because CO_2 is not subject to a trading system and thus cannot be readily assigned a monetary value. ESCT default inputs were relied on in determining emissions factors. The figures used in the analysis to represent the value of SOx and NOx are based on allowance trading price quotes for these gases supplied by Evolution Markets.

4. Results

Figure 21 shows the net benefits obtained from running the ESCT for Use Case 4. Note that these results were based upon installing a 50 MW energy storage facility. Across the different technologies, the results were all negative. The two best results were zinc air (with net stacked benefits shown in Figure 22 and Table 15) and lithium ion (with net stacked benefits shown in Figure 23 and Table 16). The worst result was for the above-ground CAES unit.

Figure 21: Net Benefits for Use Case 4

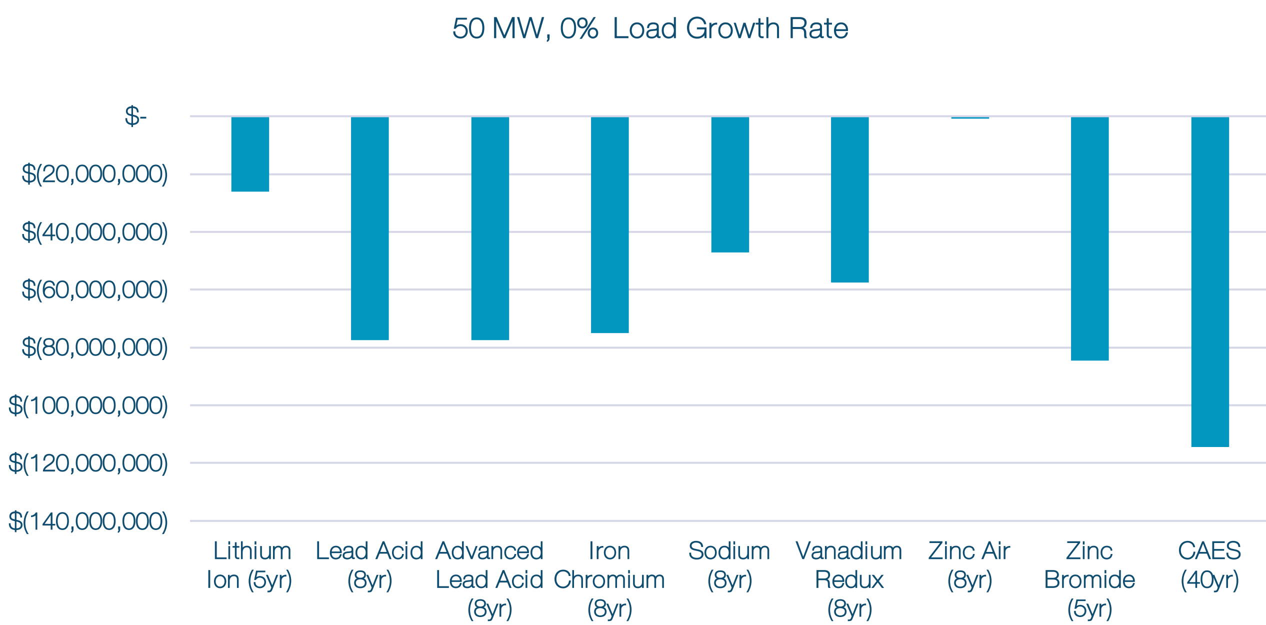


Figure 22: Net Stacked Benefits for Use Case 4 – Zinc Air

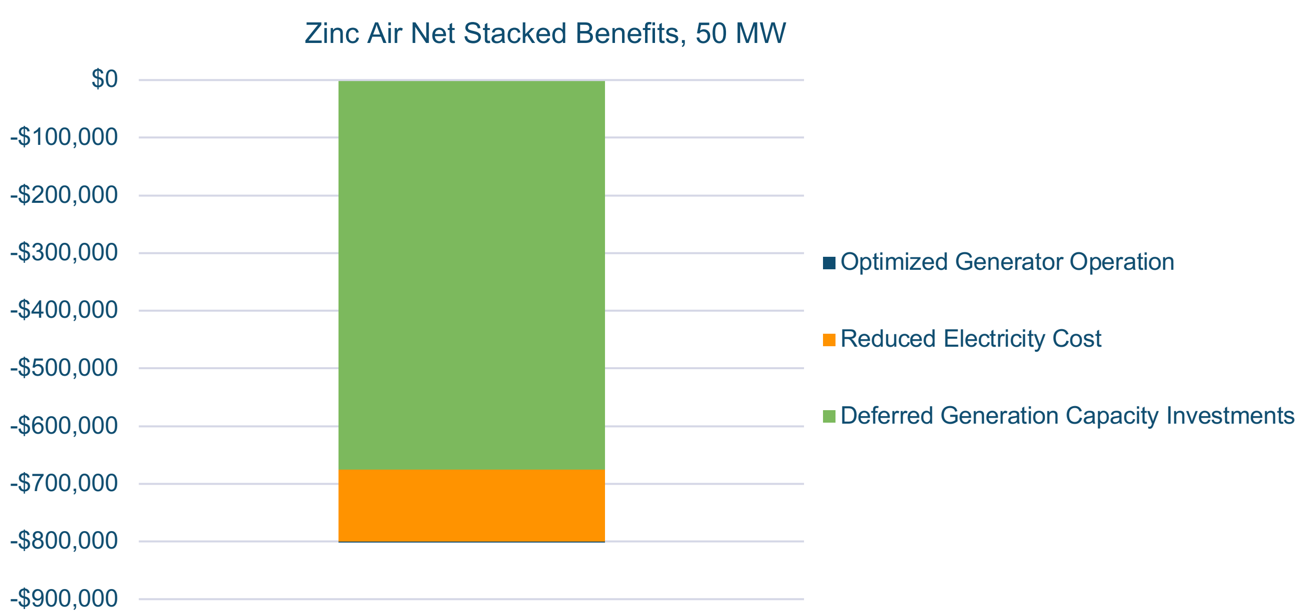


Table 15: Zinc Air Stacked and Net Stacked Benefits – Use Case 4

Project Outcome	Value
Gross Benefits	
Total	**$67,151,600**
Deferred Generation Capacity Investments	$56,728,000
Reduced Electricity Cost	$10,395,700
Optimized Generator Operation	$30,800
Cost of Deployment, Total	**$67,951,800**
Net Benefits	
Total	**$(800,200)**
Deferred Generation Capacity Investments	$(675,989)
Reduced Electricity Cost	$(123,878)
Optimized Generator Operation	$(367)

Figure 23: Net Stacked Benefits for Use Case 4 – Lithium Ion

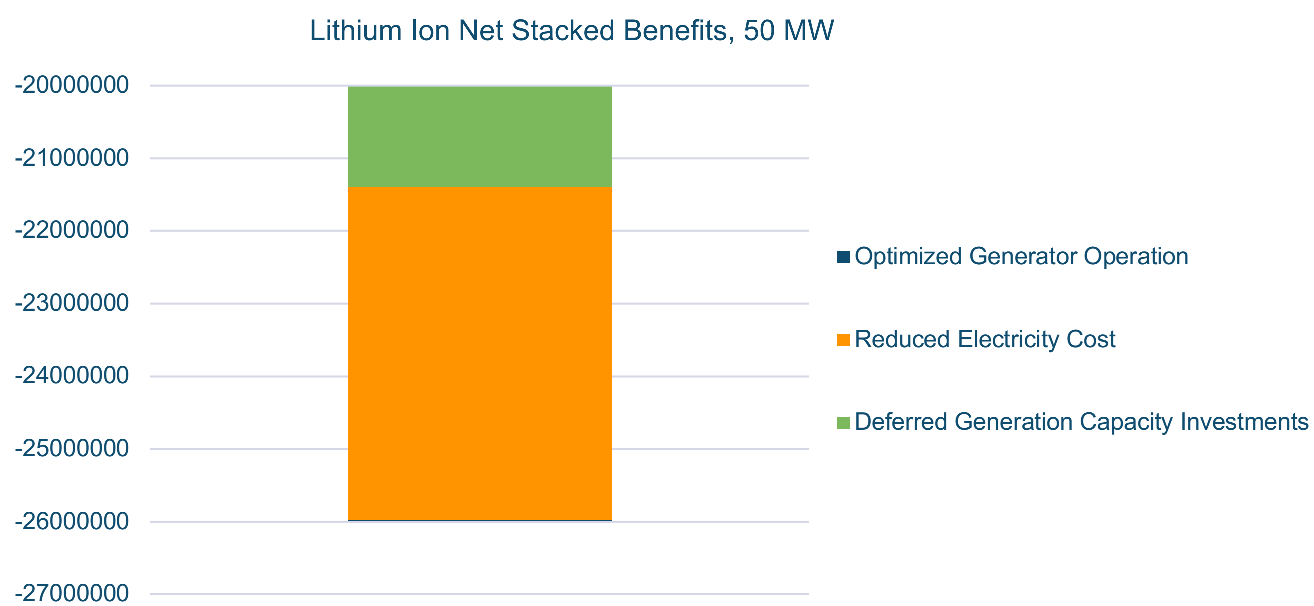


Table 16: Lithium Ion Stacked and Net Stacked Benefits Table – Use Case 4

Project Outcome	Value
Gross Benefits	
Total	**$47,810,200**
Deferred Generation Capacity Investments	$39,356,900
Reduced Electricity Cost	$8,434,400
Optimized Generator Operation	$20,900
Cost of Deployment, Total	**$73,798,200**
Net Benefits	
Total	**$(25,988,000)**
Deferred Generation Capacity Investments	$(21,393,073)
Reduced Electricity Cost	$(4,584,653)
Optimized Generator Operation	$(11,361)

5. Recommendations

The results from Use Case 4, both technical and economical, show that the value for this particular amount of energy storage in the Southeast was not profitable. However, that is not to say that a different amount of energy storage might have the potential to be attractive to utilities. Careful analysis of the utility system with updated system information would allow the utility to consider this use-case scenario. Again, battery technologies such as lithium ion and zinc air were most favorable and yielded the most benefits, which could increase as battery costs continue to trend downward. Lithium ion is a well-established technology that has been deployed in utility applications. Zinc air is a technology that is gaining interest at utility scale due to its cheaper costs, long life, and recently reported improvements in recharge limitations.

Figure S5: Asheville Energy Plant [83]

Duke Energy has applied for regulatory approval for a 9-MW lithium-ion battery energy storage facility to be placed in service in 2019 near the site of an Asheville, North Carolina coal plant retirement. “That fact that we’ve gone from Duke Energy using old coal-fired power plants in that region in the state, to a mix of gas turbines and energy storage I think is a good sign,” said Stephen Kalland executive director at the North Carolina Clean Energy Technology Center. “And probably a harbinger of things to come, not just from Duke, but from other utilities.”

The main benefit in this case would be the deferred generation capacity investment. This result would only differ with the expected lifetime of the energy storage technology. Therefore, it is recommended that utilities consider energy storage at the planning stage where capital deferral is a factor. Other benefits included reduced electricity cost and optimized generator operation.

E. Use Case 5: Grid Resiliency in the Event of Natural Disasters

1. General Narrative

Introduction

Reliability of electric grids is compromised because of their vulnerability to weather events and natural hazards (e.g., floods, thunderstorms, hurricanes). Current trends in weather patterns, such as increasing intensities of natural hazards, are projected to continue. According to data of past events, power system elements, such as transmission lines, distribution lines, transformers, etc., are the most vulnerable to such weather trends [32].

The United States spends about $55 billion annually to recover from local infrastructure damage, including power outages and grid disruptions, caused by hazardous events [33]. This section of the report explores the resiliency of the energy grid in the Southeast and if and how energy storage can contribute to the reliability and resiliency of the grid in the region.

An August 2013 White House report states that energy storage will play an integral role in enhancing grid resilience against weather-induced outages and other potential disruptions [34]. Energy storage technology could assist in improving emergency preparedness. Stored energy provides redundancy options in areas with limited transmission capacity, transmission disruptions, or volatile demand and supply profiles [35]. Three goals for addressing energy storage challenges follow:

1. Energy storage should be a broadly deployable asset for enhancing renewable penetration.

2. Energy storage should be available to industry and regulators as an effective option to resolve issues of grid resiliency and reliability.

3. Energy storage should be a well-accepted contributor to realization of smart-grid benefits [35].

Currently, utility companies do not allow islanding. Non-interconnected island systems are supplied by autonomous power stations, which yield high generation costs but could potentially cover the complete demands in terms of yearly energy balance [36]. The combination of using islanding and energy storage could contribute to the reliability and resiliency of the grid.

This report establishes the characteristics of a resilient power grid, assesses the current hardening and resiliency activities practiced in the Southeast, and outlines natural hazards that have created concern about the need for bulk energy storage. Data from past events are used to determine the risks imposed to energy grids in the Southeast. The results may determine if the vulnerability of the grid to weather events in the region justifies the deployment of energy storage technology. Vulnerability of the grid to weather affects the maintenance cost of the system, its reliability, and planned improvements to the system. Existing data of previous weather events are used to determine the economic losses due to power outage and the costs associated with current resiliency activities.

Characteristics of a Resilient Power Grid

For a power gird to be resilient, it should be robust, stable, adaptive, flexible, resourceful, agile, capable of coordination and foresight, redundant, diverse, collaborative, and efficient [33]. Descriptions of the characteristics are detailed below.

- **Robust, Stable, and Adaptive** – The grid should be able to withstand damage and exposure for long periods while maintaining standard performance levels. In the event of a compromising event, essential operations must be prioritized, and initial performance levels should be returned quickly after the disturbance. Data from these events must be archived so that the grid can be adapted to lower the risk of outages in the future.

- **Flexible** – In the case of extreme events, the power system should be able to switch between different modes of operations in order to protect the integrity of the system.

- **Resourceful and Agile** – The power grid system should have a proactive mechanism capable of identifying patterns of the immediate environment and preemptively switch to the preparatory mode of operation.
- **Capable to Coordination and Foresight** – The power grid should be connected to the main managerial system to coordinate preparation and recovery actions.

- **Redundant –** A resilient power grid should have provisions for an acceptable level of operation if some components are damaged during weather events. The redundant components should be available to maintain the operation of the grid.

- **Diverse –** The infrastructure of the grid should be diverse in terms of patterns, structure, supply resources, providers, and output methods in case any of the components are shut down due to damages.

- **Collaborative –** A power grid system should be based on an extensive range of stakeholders in the decision-making process to ensure a wide range of opinions and views on its stability.

- **Efficient** – A resilient power grid should have a high-energy return on available resources.

Current Hardening and Resiliency Activities Practiced in the Southeast

Aging infrastructure is more susceptible than newer assets to the hurricane-related hazards of storm surge, flooding, and extreme winds. The electricity transmission system stretches nearly 200,000 miles. Most of the system was designed to last 40 to 50 years; however, in some parts of the country, it is already 100 years old [37].

The most common resiliency activity reported by utilities is pole inspection and maintenance. A multiyear inspection and maintenance cycle for all transmission circuits, a multiyear wood pole treatment cycle, and a galvanized steel painting program to prevent corrosion on steel structures have been instituted by Southeast and Gulf Coast utilities [37]. Another common resiliency practice is vegetation management. Clearing potentially damaging tree limbs and other vegetation from power line rights-of-ways can prevent power loss. Table 17 outlines several energy hardening and resiliency activities on the Gulf Coast.

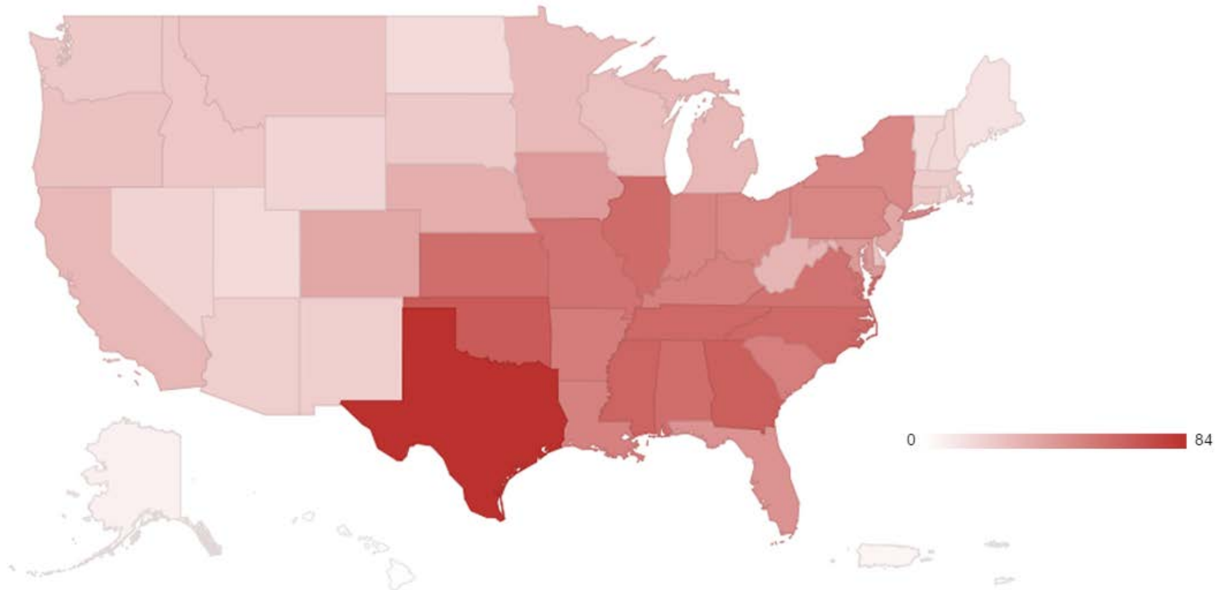
Table 17: Energy Hardening and Resiliency Activities on the Gulf Coast [37]

Activity Type	Objectives	Methods
Hardening	**Flood Protection**	Elevating substations/control rooms/pump stations.
		Relocating/constructing new lines and facilities.
	Wind Protection	Upgrading damaged poles and structures.
		Strengthening poles with guy wires.
		Burying power lines underground.
	Modernization	Deploying sensors and control technology.
		Installing asset databases/tools.
Resiliency	**General Readiness**	Conducting hurricane preparedness planning and training.
		Complying with inspection protocols.
		Managing vegetation.
		Participating in mutual assistance groups.
		Purchasing or leasing mobile transformers and substations.
		Procuring spare T&D equipment.
	Storm-Specific Readiness	Facilitating employee evacuation and reentry.
		Securing emergency fuel contracts.
		Supplying logistics to staging areas.

History of the Resiliency of the Grid to Natural Hazards in the Southeast

The Southeast region of the United States is known for producing the most billion-dollar disasters in the country [38], as illustrated in Figure 24.

Figure 24: Distribution of Billion-Dollar Disasters [38]



Power outages caused by floods, thunderstorms, tornadoes, wind, ice, and hurricanes in the Southeast were totaled starting from the year 2000. The summary is shown in Table 18.

Table 18: Power Outages in the Southeast, 2000-2014 [39]

Cause of Outage	Number of Customers Affected	Average Duration of Outage (in Days)
Flood	1,126,772	1
Thunderstorm	10,388,969	1.5
Tornado	639,589	1.7
Wind	1,518,670	1.4
Ice	3,013,240	3.2
Hurricane	40,108,315	11

[1]States classified as part of the Southeast: Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Texas, and Virginia.

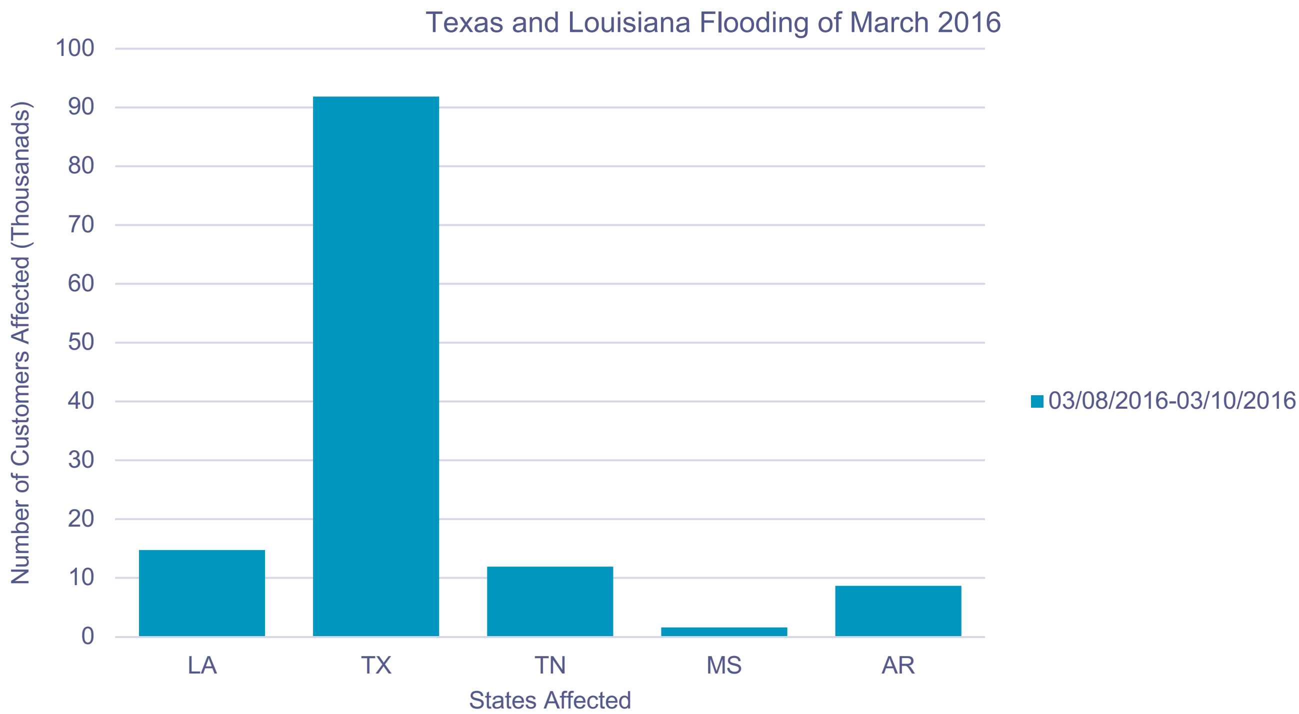
Grid Resiliency to Floods

The grid's resiliency to floods in the Southeast is assessed by considering the impact of previous flood events on the system and determining the projected level of risk. The two events discussed include the Texas and Louisiana flooding of March 2016 and the Houston flooding of April 2016.

Past Events

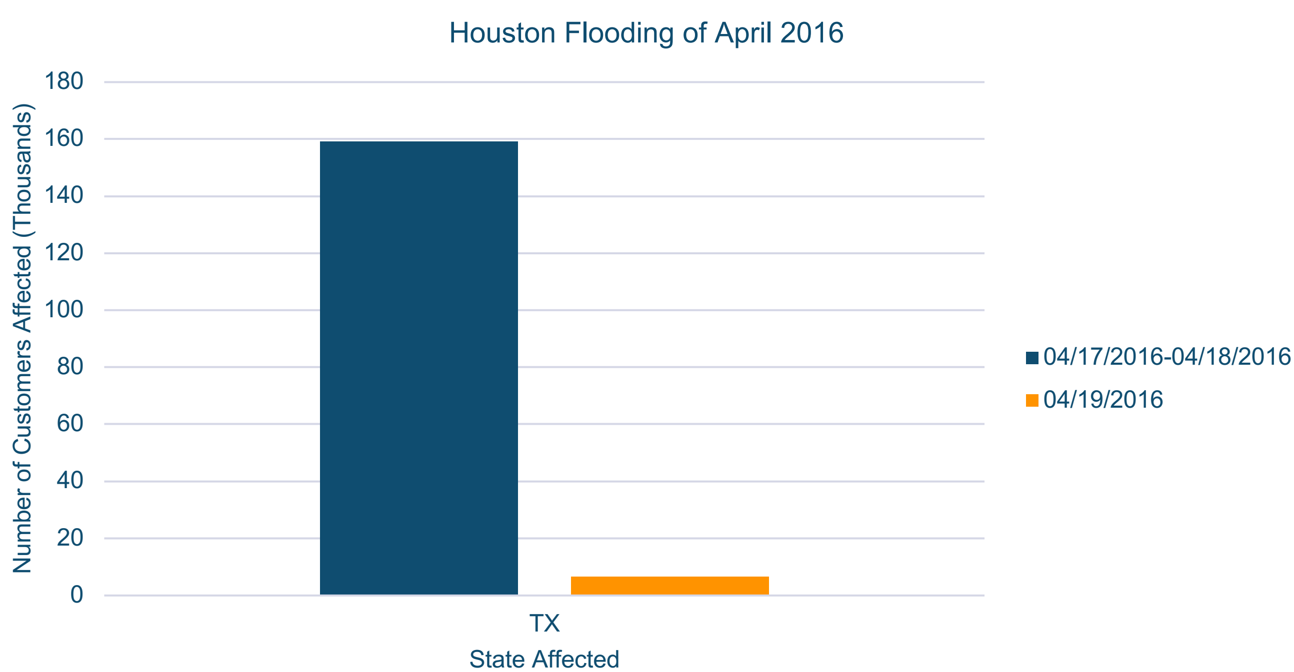
In March 2016, a heavy rain produced record flooding along the Sabine River, which marks the border between Texas and Louisiana. The heaviest rain was observed in northwest Louisiana [40]. The flooding damaged thousands of houses, roads, and bridges. The power outages from the flooding are shown in Figure 25.

Figure 25: Power Outages from March 2016 Flood [41] [42] [43] [44]



In April 2016, Houston, Texas, experienced a period of extreme rainfall, reaching up to 30 inches over several days. Some areas experienced a 1-in-500-year event [38]. Thousands of homes and businesses were damaged from the event. The power outages caused by the flooding is shown in Figure 26.

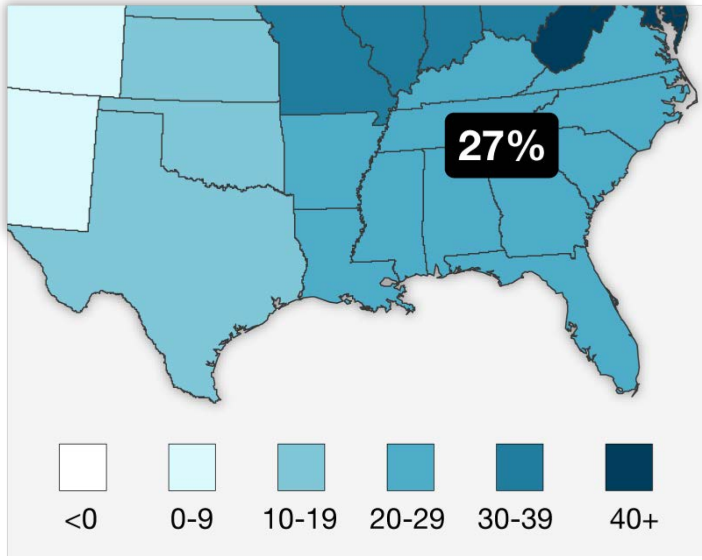
Figure 26: Power Outages from August 2016 Flood [45] [46] [47]



Projected Level of Risk

The East and Gulf Coasts of the United States have experienced much higher and faster rates of sea-level rise than the global average [48]. The risk of coastal flooding from storm surges is growing due to rising sea levels. Electricity infrastructure along the East and Gulf Coasts is threatened by this trend [49]. The trend of increasing intensity of precipitation also threatens electricity infrastructure. The change in precipitation between 1958 and 2012 is shown in Figure 27.

Figure 27: Percentage Change in Very Heavy Precipitation from 1958 to 2012 [88]



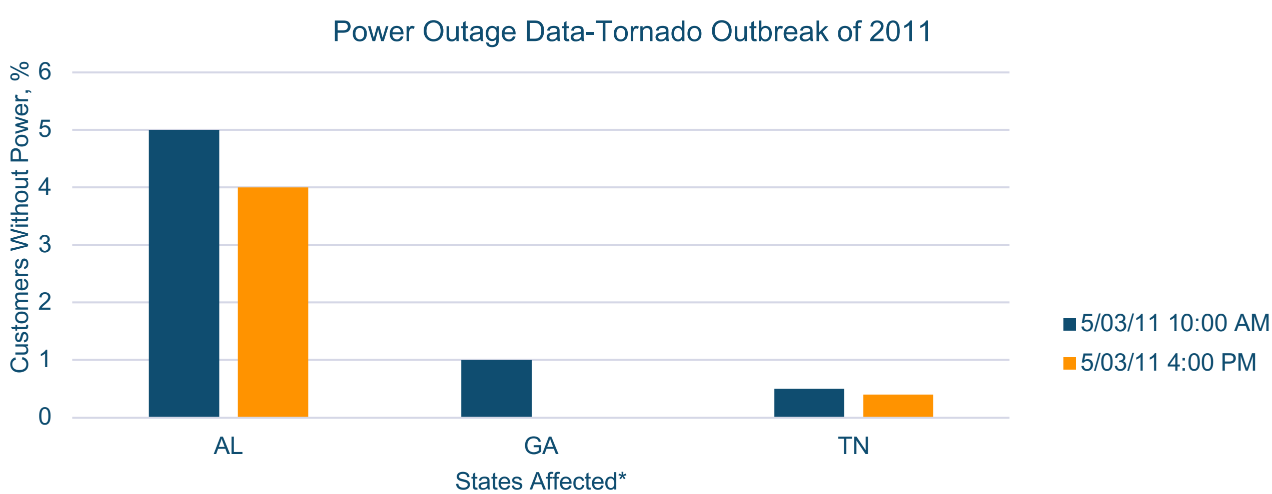
Grid Resiliency to Thunderstorms

The grid's resiliency to thunderstorms in the Southeast is assessed by considering the impact of previous thunderstorms on the system and determining the projected level of risk. Tornadoes and wind are included under the thunderstorm category. The tornado outbreak of 2011 is discussed in the following section.

Past Events

The largest tornado outbreak in world history occurred in late April 2011, affecting Alabama, Georgia, Mississippi, Tennessee, and Missouri. There were 334 separate tornado touchdowns during this outbreak. The Southeast and the Tennessee Valley suffered catastrophic damage. At the height of the event, nearly one million residents lost electricity [50]. Several power lines and poles were downed by tornados and falling trees. The tornado outbreak was assessed by the Mitigation Assessment Team (MAT). The effects of the high winds on infrastructure were not always the result of direct damage but rather the result of damage to the utilities that served the infrastructure. High winds did not damage the infrastructure that was investigated, but it did damage the electric lines that fed the systems. The most serious consequences of the tornado outbreak involved the loss of electrical power [51]. The power outages that resulted from this outbreak are detailed in terms of affected customers by state in Figure 28.

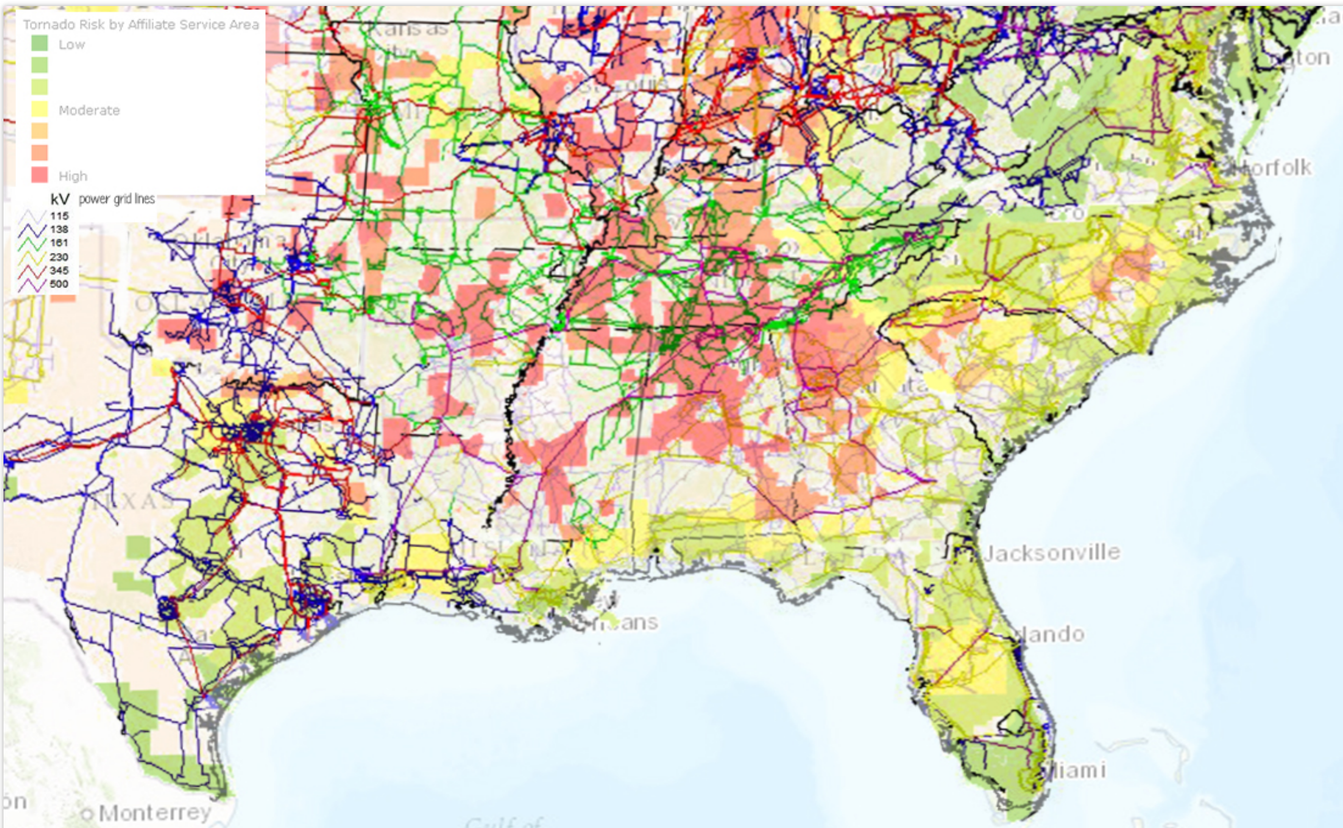
Figure 28: Customers Affected by Power Outages Due to 2011 Tornado Outbreak [52]



Projected Level of Risk

Parts of Alabama, Arkansas, Florida, Georgia, Mississippi, Tennessee, and Texas are at the highest risk of tornadoes in the Southeast annually, as shown in Figure 29. Overhead power lines, transmission towers, and substations are especially vulnerable to thunderstorms because they are usually located outside [32]. Due to cost and maintenance, there are many more overhead lines than underground cables. This fact is concerning because high winds can cause debris to blow into power lines or trees to fall onto power lines.

Figure 29: Tornado Risk in the Southeast [53]



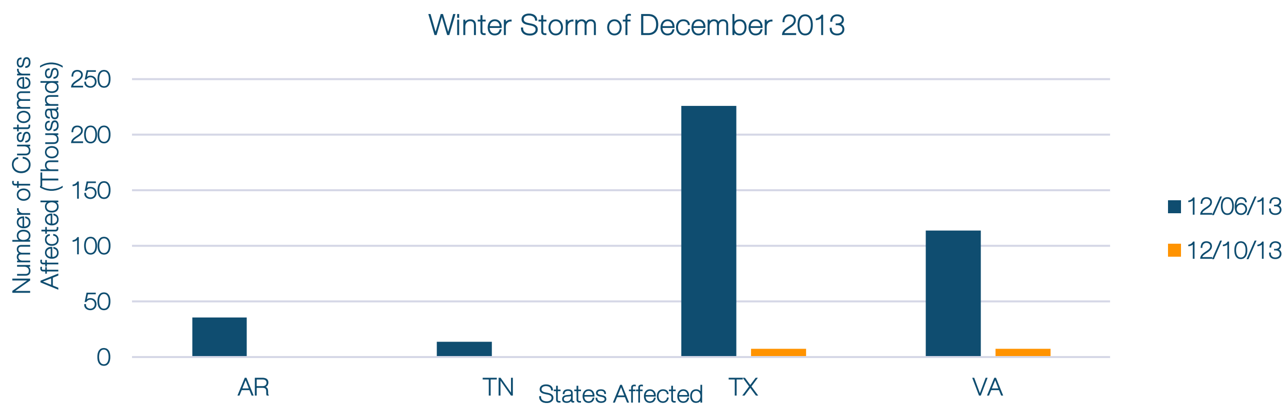
Grid Resiliency to Ice

The grid's resiliency to ice in the Southeast is assessed by considering the impact of previous ice events on the system and determining the projected level of risk. All types of winter weather are included under the ice category. The events discussed include the winter storm of December 2013 and the winter storm of February 2014.

Past Events

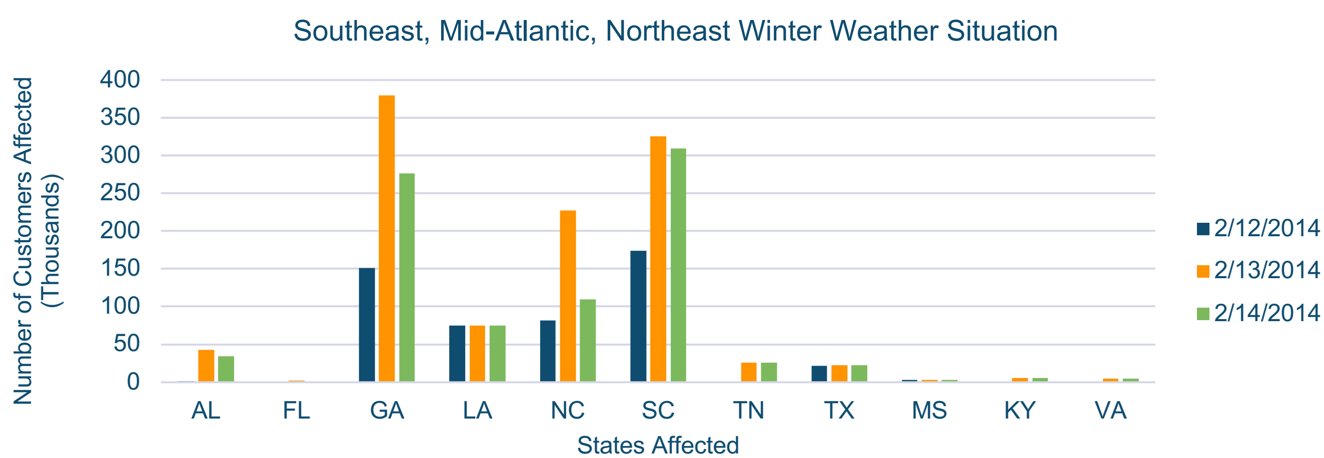
A winter storm moved across the central and eastern United States in December 2013. Arkansas, Tennessee, Texas, and Virginia experienced power outages from the storm. The impact of the power outages in terms of affected customers by state is shown in Figure 30.

Figure 30: Customers Affected by Power Outages Due to Winter Storm of December 2013 [54] [55]



In February 2014, a winter storm affected every state in the Southeast. Many power outages occurred because of ice toppling trees and branches [56]. The impact of the power outages in terms of affected customers by state is shown in Figure 31.

Figure 31: Customers Affected by Power Outages Due to Winter Storm of February 2014 [56] [57] [58] [59] [60]



Projected Level of Risk

In regions that are prone to ice and snow, transmission towers and lines are designed to handle ice and wind [32]. Since the Southeast rarely experiences significant ice and snow events, the energy infrastructure is not designed to tolerate heavy frozen precipitation.

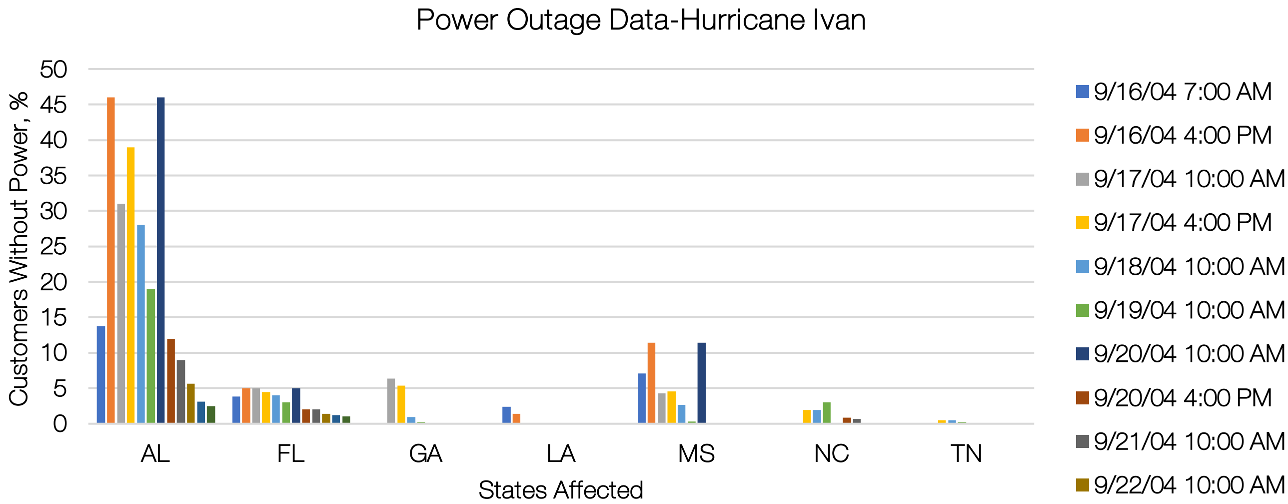
Grid Resiliency to Hurricanes

The grid's resiliency to hurricanes in the Southeast is assessed by considering the impact of previous hurricanes on the system and determining the projected level of risk. Three significant hurricanes that impacted the Southeast are discussed in the following section.

Past Events

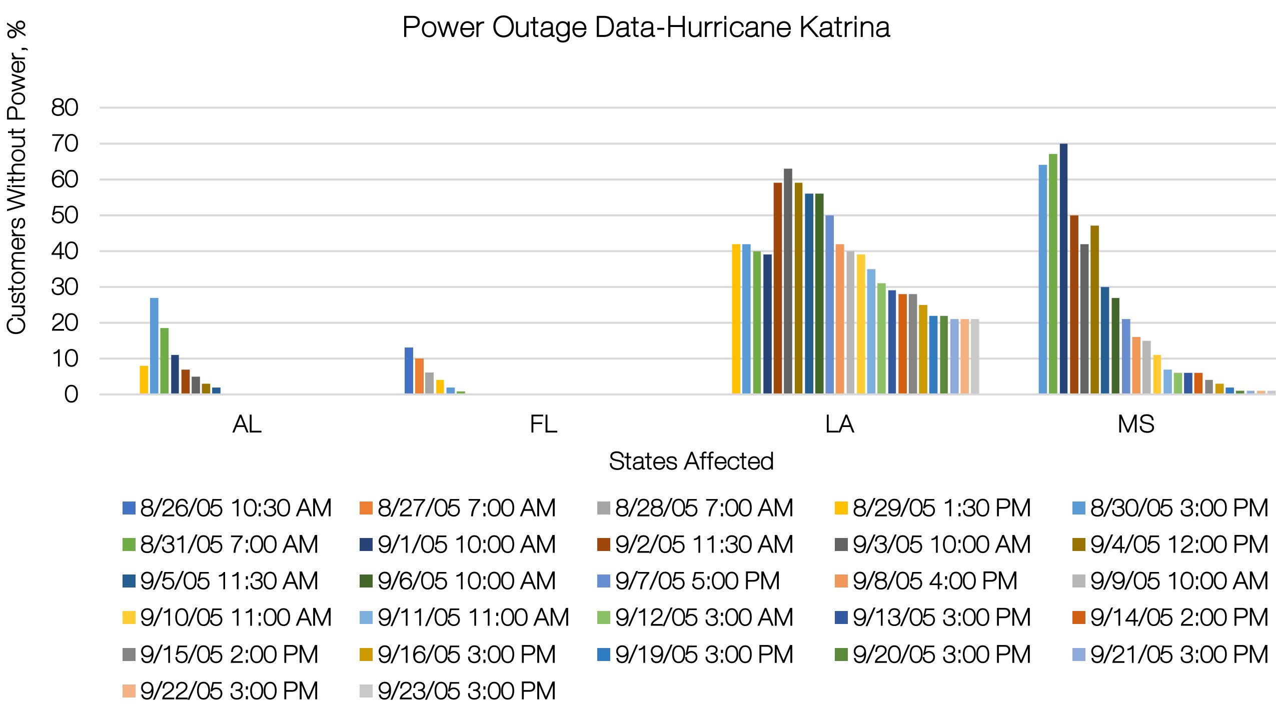
On the morning of September 16, 2004, Hurricane Ivan made landfall near Gulf Shores, Alabama, as a Category 3 hurricane. Wind speeds reached 120 mph at landfall [61].The impact of related power outages in terms of affected customers by day and state is shown in Figure 32.

Figure 32: Customers Affected by Power Outages Due to Hurricane Ivan [62]



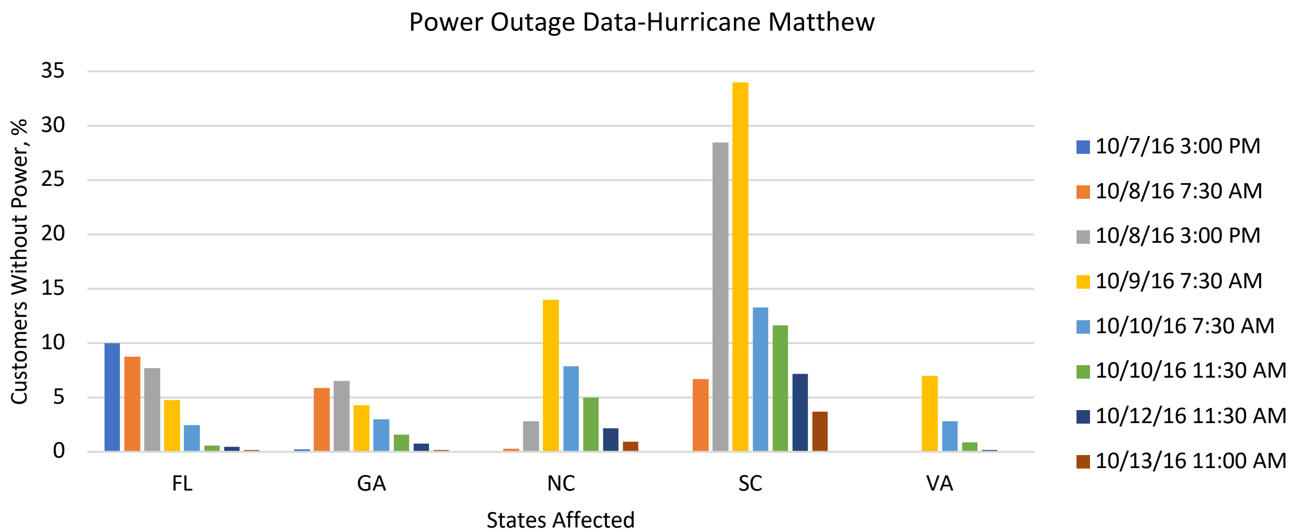
On August 23, 2005, Hurricane Katrina made landfall. Hurricane Katrina is the deadliest hurricane to strike the United States since the Palm Beach-Lake Okeechobee hurricane in September 1928. Katrina produced damage estimated at $75 billion in the New Orleans area and along the Mississippi coast [63], making it the costliest U.S. hurricane on record. Alabama, Florida, Louisiana, and Mississippi are the states in the Southeast that were most heavily affected by Hurricane Katrina. The impact of related power outages in terms of affected customers by state and day is shown in Figure 33.

Figure 33: Customers Affected by Power Outages due to Hurricane Katrina [64]



On September 28, 2016, Hurricane Matthew made landfall as a Category 5 hurricane. Florida, Georgia, the Carolinas, and Virginia were the southeastern states affected by the hurricane. The impact of related power outages in terms of affected customers by state and day is shown in Figure 34.

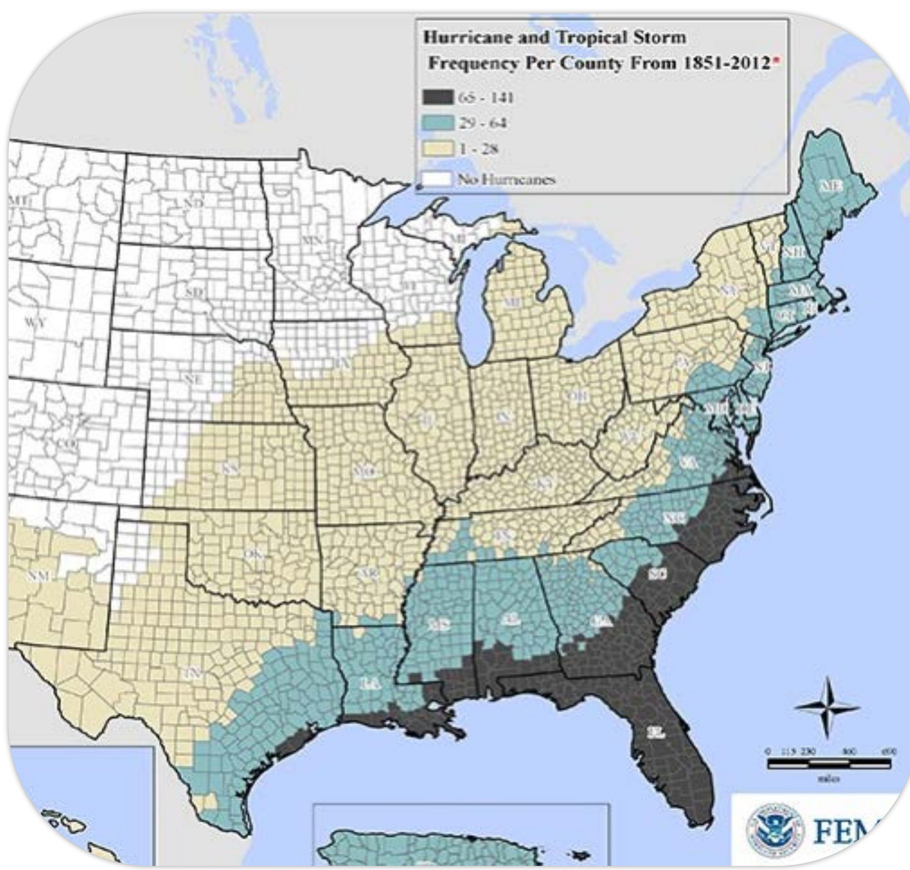
Figure 34: Customers Affected by Power Outages Due to Hurricane Matthew [65]



Projected Level of Risk

Hurricanes represent the top cause of power outages in the Southeast. Hurricanes cause the highest number of outages for the longest durations. In the North Atlantic, there were 43% more tropical storms, 51% more hurricanes, and 47% more Category 4 and 5 storms in the 1995-2005 period than in the previous decade with the highest recorded number of such events [66].The frequency of hurricanes and tropical storms is highest along the Southeast coastline, as shown in Figure 35.

Figure 35: Frequency of Hurricane and Tropical Storm Activity by County, 1851-2012 [84]



Grid Resiliency to Seismic Activity

The grid's resiliency to seismic activity in the Southeast is assessed by considering the impact of previous seismic activity on the system and determining the projected level of risk.

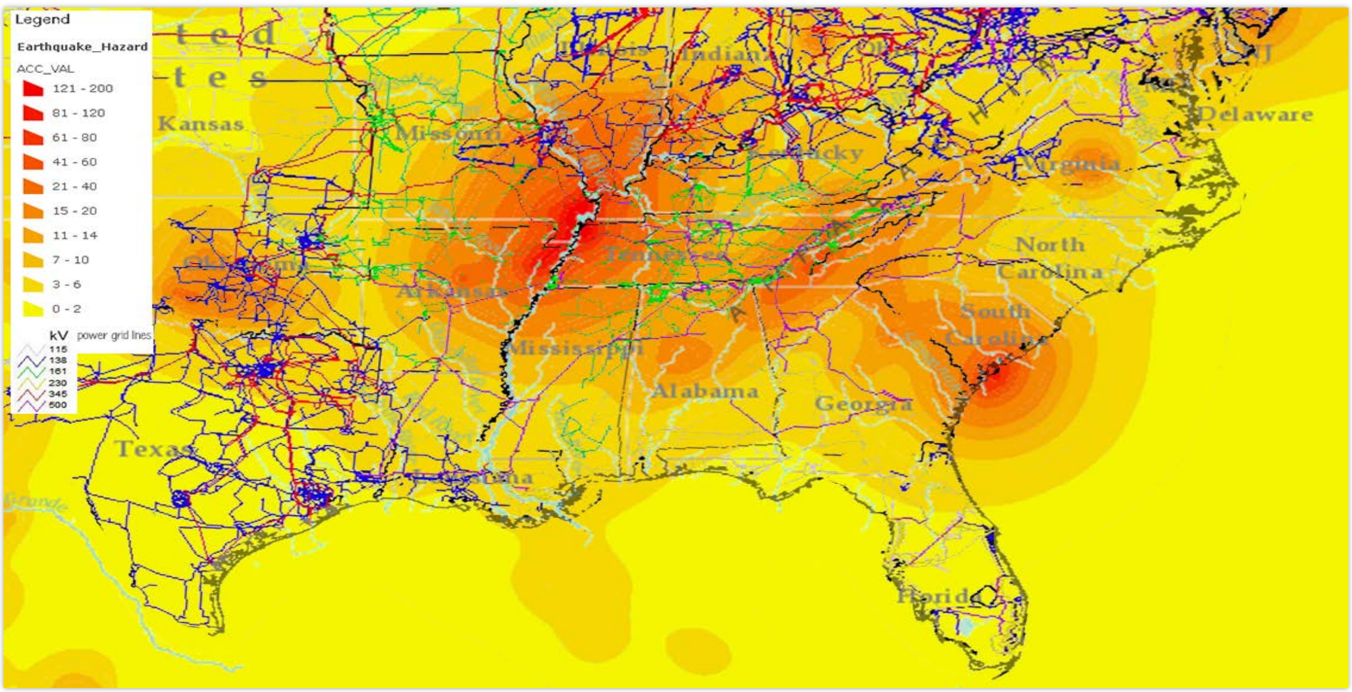
Past Events

There have not been any concerning earthquakes in the Southeast in centuries; however, there is a major seismic zone in the Southeast that is potentially one of the largest and most hazardous, known as the New Madrid Seismic Zone. Though events of significant magnitude do not occur often, the effects of a significant earthquake could be severe for the Southeast. A series of destructive earthquakes in and near New Madrid, Missouri, from December 1811 to February 1812 affected Illinois, Alabama, Indiana, Missouri, Arkansas, Kentucky, Tennessee, and Mississippi [67]. Records of events went largely overlooked until the 1970s when the Mississippi River Valley was evaluated for the construction of nuclear power plants. Seismometers were installed in the region during the 1970s, and the New Madrid Seismic Zone was identified as an area of significant earthquake hazards.

Projected Level of Risk

As shown in Figure 36, the Southeast has two concerning areas for earthquake hazards. If an earthquake occurs in either of these areas, the Southeast could endure significant damage to electrical infrastructure.

Figure 36: Transmission Lines and Earthquake Hazards in the Southeast [68] [69]



2. Power System Analysis

Introduction

The benefits of energy storage to a power system were evaluated using a production-cost model. The production-cost model simulates changes of power system operations as additional energy storage is added. To show the benefits of energy storage under different conditions, several scenarios were tested. The power system was evaluated with and without energy storage during normal operations and during power-outage events occurring at different times of the day. The data used to perform the simulation in this study were obtained from publicly available resources. To accurately calculate benefits of energy storage, actual system-operating data should be used.

Production-Cost Model

The MSU team constructed a production-cost model. The model solves for the economic scheduling of generating units and energy storages for serving the hourly load demand, adhering to specified constraints. The overall approach is to compare the total costs of the power system with and without energy storage. Any reduction in cost is considered to be a benefit of energy storage. The objective of the production-cost model is to minimize the operating costs based on generating unit offers and the power system load-shedding costs. The adhering constraints are the following: for a generating unit, the capacity limits are included, which indicate that the output power of a generating unit should operate within its maximum and minimum limit; the generating unit's minimum ON/OFF time limits are included, which indicate the minimum ON/OFF time a generating unit should stay when it is turned ON/OFF; the generating unit's ramping UP/DOWN limits are included, which indicate that the changes of a generating unit's output between successive time periods should be within the limits. For the power system, the power balance constraints are included, which indicate the system should provide enough power to meet the demand of load; the transmission line power flow limits are included, which indicate the transmission lines' capacity; and the load shedding limits are included, which indicate the range of load-shedding amount.

For energy storage, the state-of-charge constraints are included, which take round-trip efficiency factors into consideration. The state-of-charge constraints indicate the relationship between the energy storage's current state and its previous state. A round-trip efficiency factor shows that energy charged into storage cannot be fully discharged back to the system due to the efficiency of the energy storage. Energy storage status constraints are included because energy storage can only be at either a charging or discharging status each moment.

The production-cost model allows users to specify load data profiles. It also allows users to specify how long the simulation should run (e.g., a few hours, a day, or a week). When the power system is specified, a solver (in this study, the CPLEX Optimizer by IBM was used) can be used to solve the production-cost model.

Optimization Horizon

A daily optimization horizon was chosen to simulate the power system. Because the volume of energy storage used in this study is relatively small compared to the power system's energy consumption level, the energy storage could only provide energy supply for several hours instead of several days in the occurrence of a power outage event. The daily optimization horizon of several hours is long enough to capture the benefits of the energy storage.

Model Dataset

Normally, a production-cost model would be created using load data profiles from utility companies. Because specific utility data were not provided for this simulation, the MSU team modified a new dataset based on public resources [2]. Actual hourly load data from the Midcontinent Independent System Operator (MISO) local resource zones 8, 9, and 10 were found in MISO's database and scaled down to reflect the studied system load. The MISO zones used included parts of Arkansas, Louisiana, and Mississippi. IEEE 118 Bus Test Case data were used to simulate the configuration of the system [70].

Study Methodology Strengths and Limitations

A strength of the production-cost model is its ability to derive the total costs of power generation and load shedding with and without energy storage. Accurate generating unit data, transmission network data, and load profiles can be read into the model as data files, adding realism to the simulation.

There are some limitations in this study. First, the generating unit data, such as power generation cost curve, minimum ON/OFF time, and startup costs, are different from the actual generating unit data. Second, the load data used in this study were modified according to the load data of MISO's local resource zones 8, 9, and 10 instead of the actual power system's load data. Third, the actual power system's transmission network data are not used in the case study.

Energy Storage Characteristics

Knowing the characteristics of different types of energy storage was important for choosing an energy storage type that would be compatible with the power system. Table 19 shows some key parameters of energy storage, such as power output, energy storage capacity, round-trip efficiency, and cycle life. The parameters are derived from the default values of energy storage used in the ESCT, which is funded by the DOE Office of Electricity Delivery and Energy Reliability (OE) and developed by Navigant Consulting [71]. An important note is that the default characteristics of energy storage can be modified to fit the parameters of actual energy storage.

Table 19: Energy Storage Characteristics

Energy Storage Type	Power Output (MW)	Energy Storage Capacity (MWh)	Round-Trip Efficiency (%)	Cycle Life (Cycles)
Compressed Air Energy Storage	180	800	78	13,000
Pumped Hydro Storage	530	2,150	81	13,000
Flywheel Energy Storage	20	5	86	100,000
Supercapacitor	0.0005	0.0005	94	55,000
Battery (type unspecified)	10	5	85	4,200
Battery, Sodium Sulfur	10	5	75	4,500
Battery, Lead Acid	10	5	88	3,250
Battery, Advanced Lead Acid	10	5	83	4,500
Battery, Lithium Ion	10	5	92	4,500
Flow Battery, Zn-Br	5	10	63	10,000
Flow Battery, Fe-Cr	5	10	75	10,000
Flow Battery, Vanadium	5	10	68	10,000
Flow Battery (type unspecified)	5	10	70	10,000

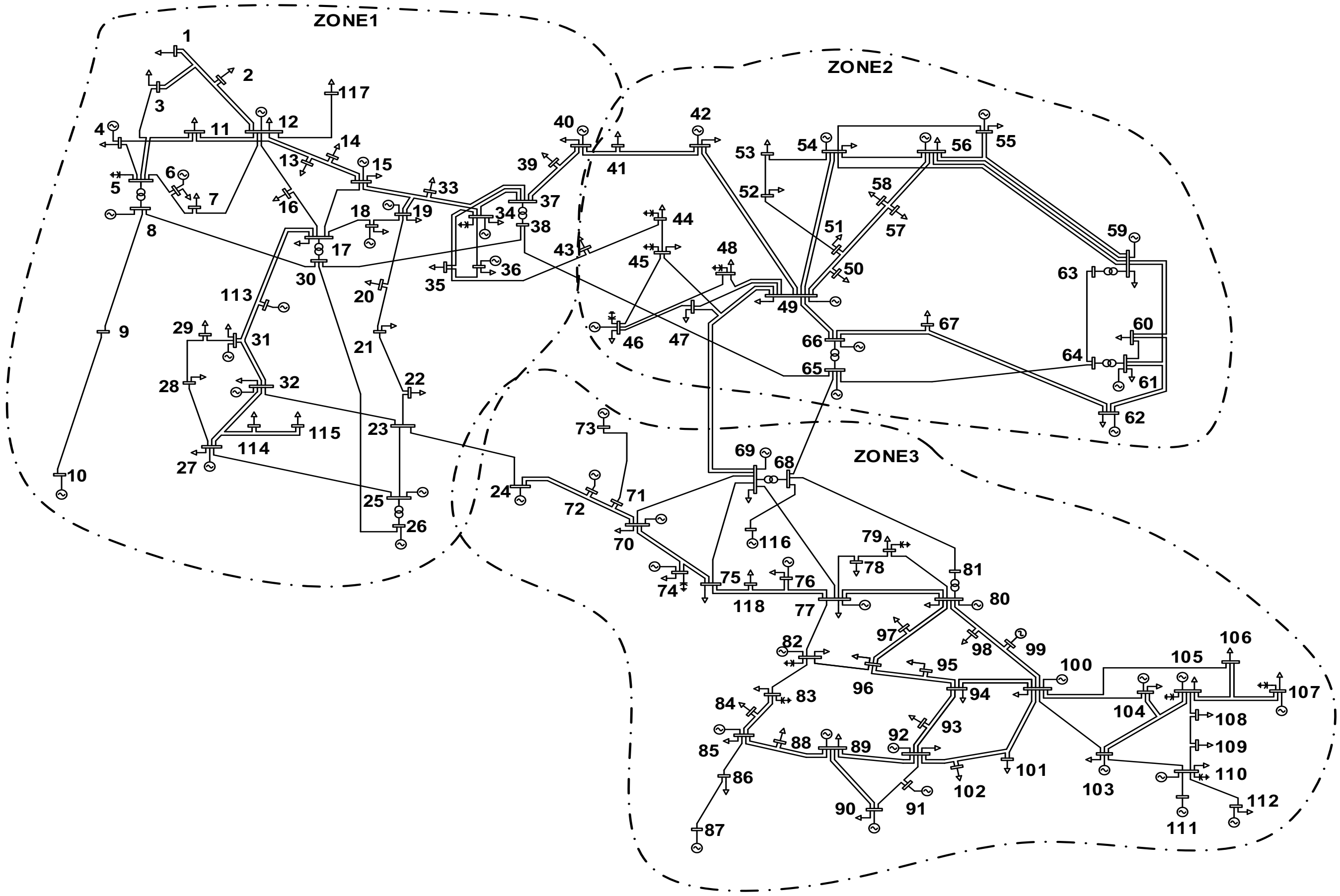
System Assumptions

Table 20 describes the system assumptions that were utilized in this study. The transmission network of IEEE 118 Bus Test Case, which includes 118 buses, 186 branches, 91 load sides, and 56 generating units, is shown in Figure 37.

Table 20: System Assumptions

Input Data	Detail	Source
Generating Unit Data	Modified from IEEE 118 Bus Test Case	University of Washington Website [70]
Transmission Network Data	Modified from IEEE 118 Bus Test Case	University of Washington Website [70]
Load-Shedding Cost	3,500 $/MWh	MISO Evaluating Energy Offer Cap Policy [72]
Hourly Load Profile	Estimated by MISO Local Resource Zones 8, 9, and 10: Historical Hourly Load Data	MISO Daily Forecast and Actual Load by Local Resource Zone

Figure 37: Transmission Network of IEEE 118 Bus Test Case

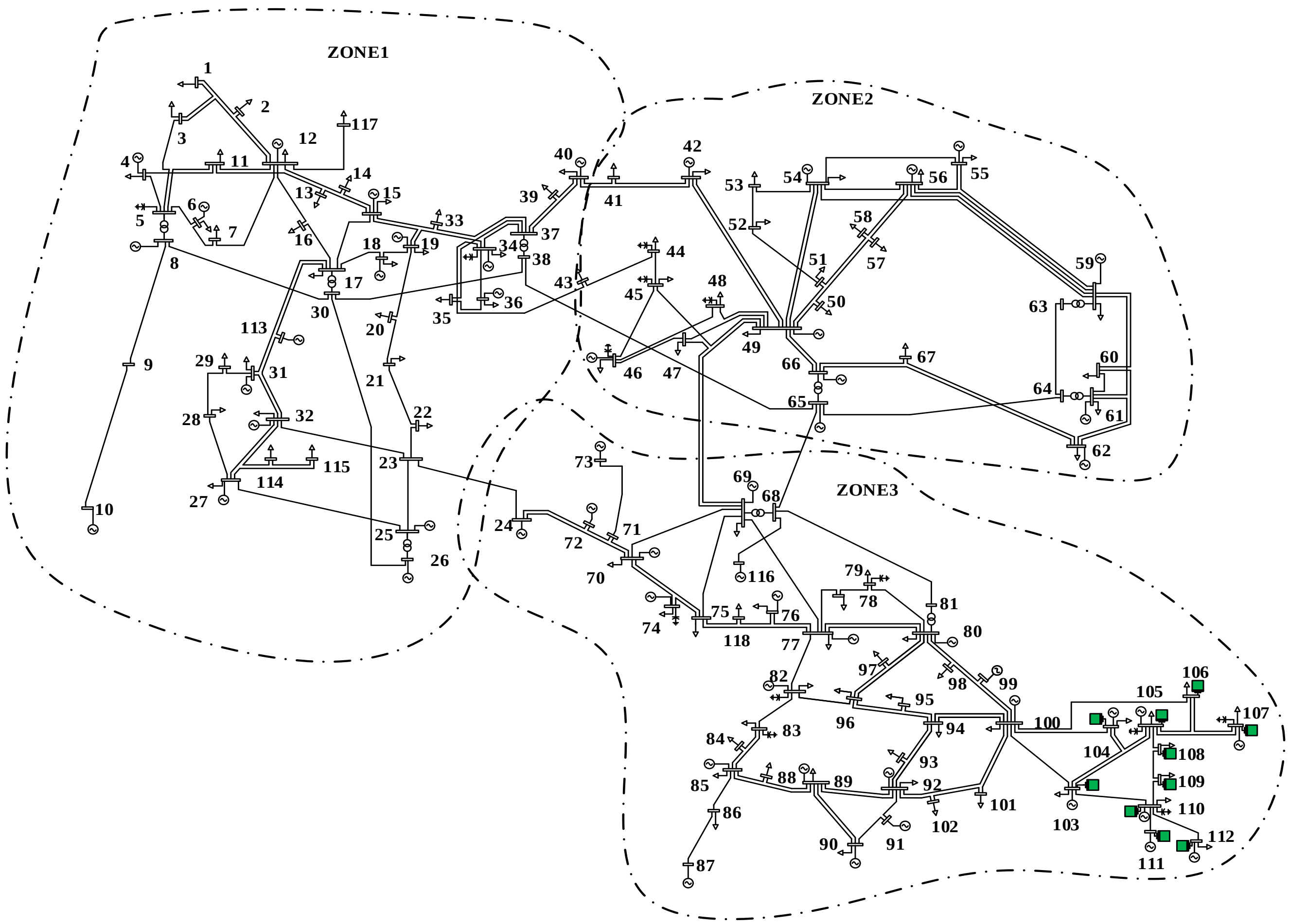


The average load level of the modified IEEE 118 Bus Test Case's load data is around 34% of the average load level of MISO's load data. Load data from the MISO local resource zones 8, 9, and 10 were scaled down to around 34% of their historical data to fit the configuration of IEEE 118 Bus Test Case. The modified and original load data from MISO that were used in this study are provided in Appendix C.

Because pumped hydro storage and compressed air energy storage are usually constrained by location and because the flow battery option is still under research, battery energy storage was chosen to represent energy storage in this simulation [73]. The initial and final state of charge were set to 20% to account for the system having energy stored at the beginning of and after the evaluation.

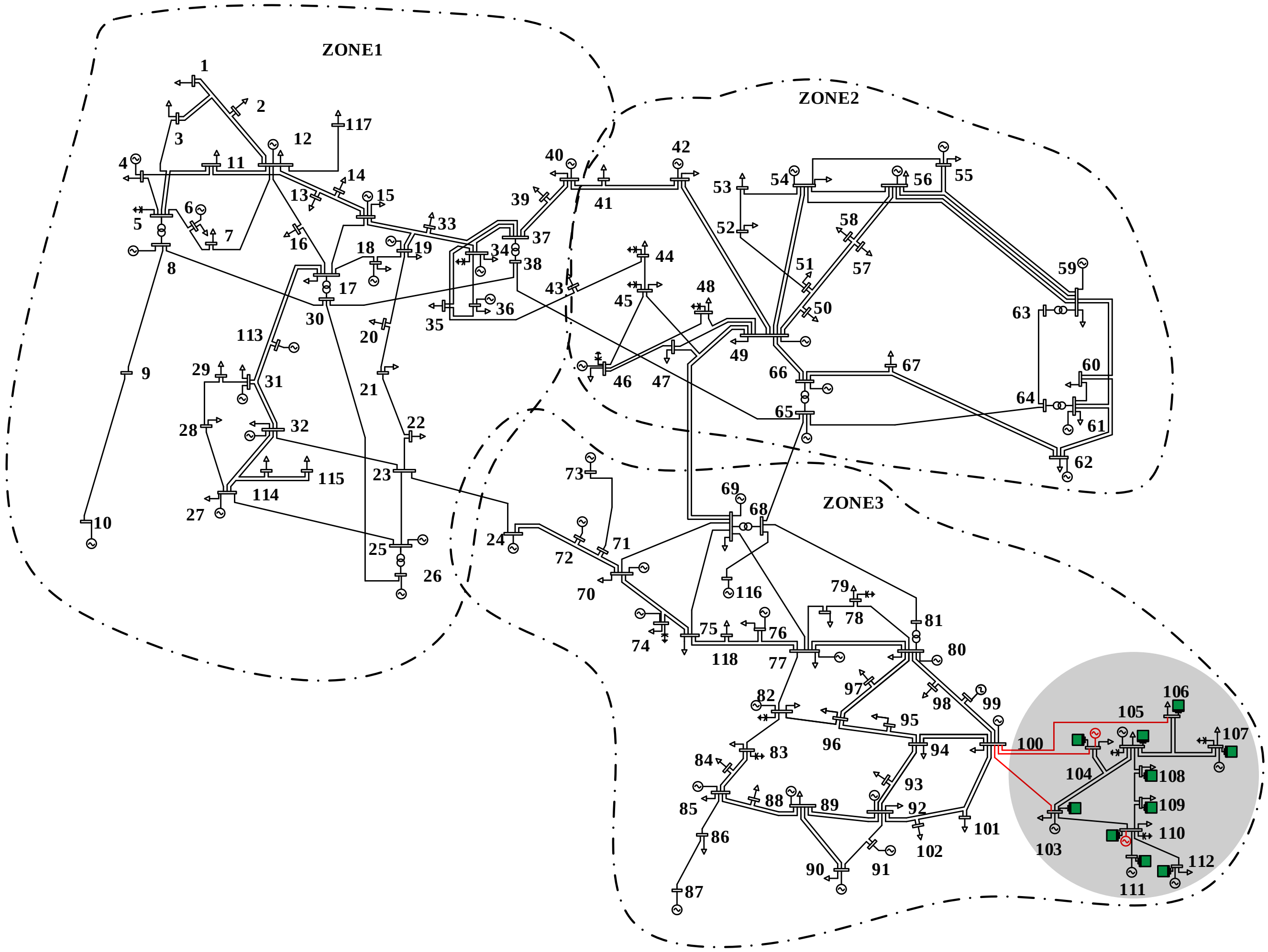
In order to eliminate load shedding in the power system, 10 energy storages were placed in the IEEE 118 Bus Test Case. The locations of energy storage are at buses 103, 104, 105, 106, 107, 108, 109, 110, 111, and 112. Figure 38 indicates the locations of energy storage with green boxes.

Figure 38: Energy Storage Locations of IEEE 118 Bus Test Case



When a power outage occurs, several generators may be out of service, and transmission lines may become disconnected. Figure 39 represents a power outage scenario. Generators at buses 104 and 110 are out of service, and the transmission lines between 100 and 103, 104, and 106 are disconnected. These outages are shown in red.

Figure 1: Islanding Case in IEEE 118 Bus Test Case



Case Descriptions

Four scenarios were evaluated for Use Case 5. The parameters of each scenario are shown in Table 21. Case 1 serves as the base case because it is the power system under normal operations without energy storage. The benefits of energy storage for a power system operating under normal conditions can be determined by comparing Cases 1 and 2. Case 3 represents how the power system will react if an outage occurs without energy storage. The benefits of energy storage during an outage can be determined by comparing Cases 3 and 4.

Table 21: Energy Storage Scenarios

Cases	Energy Storage	Weather Event/Outage
Case 1	NO	NO
Case 2	YES	NO
Case 3	NO	YES
Case 4	YES	YES

Case Results: Energy Storage Cases

The benefits of energy storage are the reduction in total costs. The costs include the combination of generating units' operating costs and the power system's load-shedding costs. The results from each case are provided in the following sections.

Case 1

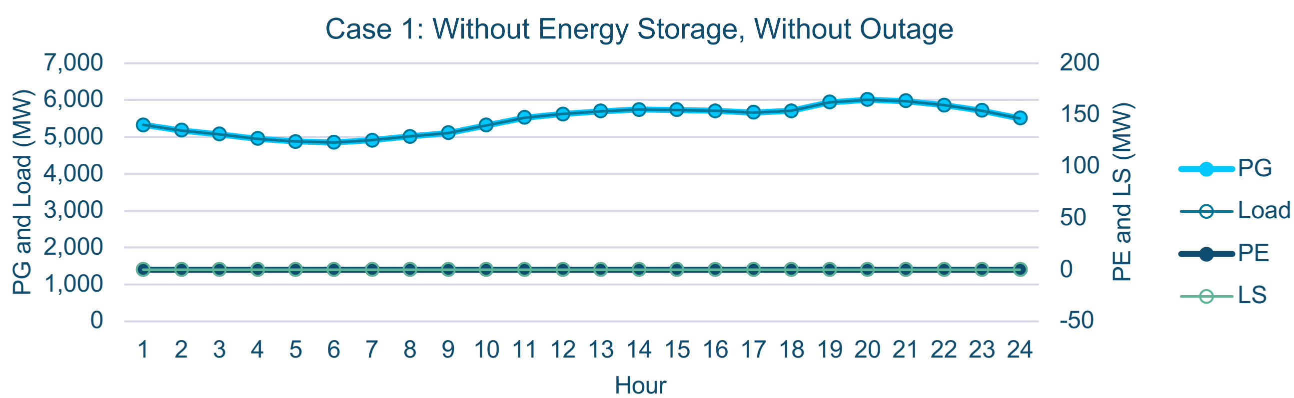
Table 22 displays the generation cost, the load-shedding cost, and the total cost of Case 1. There are no load-shedding costs since the system can provide enough power to meet the hourly load.

Table 22: Cost Details of Case 1

Generation Cost ($)	Load-Shedding Cost ($)	Total Cost ($)
1,957,907	0	1,957,907

The hourly generation output profile and the system load profile are shown in Figure 40. The left-hand vertical axis on the graph applies to the load line (in yellow) and the generation output line (in blue); the right-hand vertical axis on the graph applies to the energy-storage-output line (in orange) and the load-shedding line (in gray). Since the load-shedding cost is zero, the load line and the generation output line are overlapped.

Figure 2: Generation Output (PG), Hourly Load Profile (Load), Energy Storage Output (PE), and Load Shedding (LS) of Case 1



Case 2

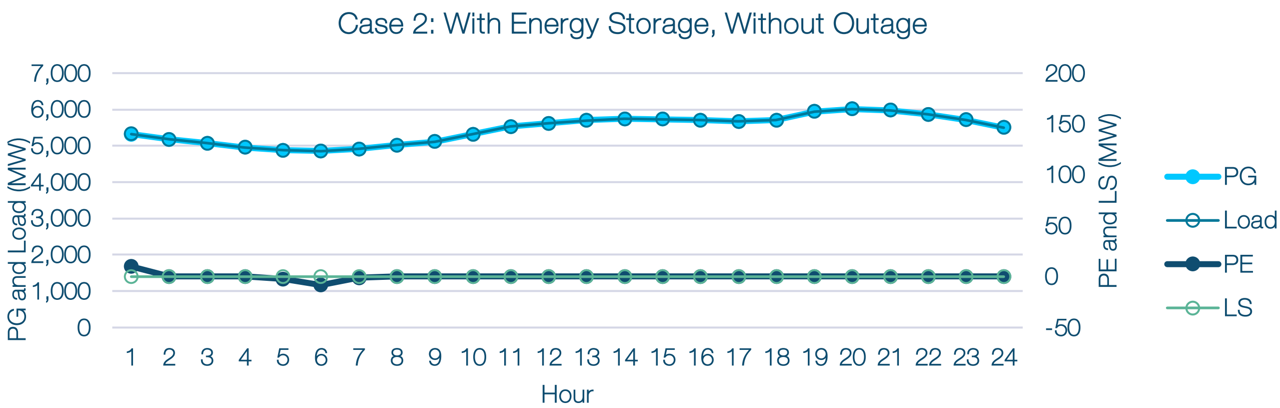
Table 23 displays the generation cost, the load-shedding cost, and the total cost of Case 2. The load-shedding cost is zero because the power system can provide enough power to meet the hourly load.

Table 23: Cost Details of Case 2

Generation Cost ($)	Load-Shedding Cost ($)	Total Cost ($)
1,957,822	0	1,957,822

The hourly generation output, energy storage output, and system load are shown in Figure 41. The presence of energy storage is reflected in the figure. When the demand is low, the power-generation cost is low and vice versa. To save on the power-generation cost, energy storages are charged at low load-demand hours (6th hour) and discharged at high load-demand hours (1st hour). The savings associated with Case 2 are around $85.

Figure 41: Generation Output (PG), Hourly Load Profile (Load), Energy Storage Output (PE), and Load Shedding (LS) of Case 2



Cases 3 and 4

The influences of three different islanding outages were tested on the power system. The islanding outage was set to occur at the lowest load-demand time of day (6th hour), at the highest load-demand time of day (20th hour), and when the load demand is almost equal to the average load level time of day (24th hour). Table 24 shows the generation cost, the load-shedding cost, and the total cost of Cases 3 and 4. Load-shedding costs occur when power outages prevent the power system from meeting the hourly load. In Case 3, the system experiences load-shedding costs when the outage occurs. The load-shedding cost is zero for Case 4 because the energy stored allows the power system to meet the hourly load.

Table 24: Cost Details of Case 3 and Case 4

Case No.	Generation Cost ($)	Load-Shedding Cost ($)	Total Cost ($)
Case 3 (Outage: 6th hour)	1,958,569	130	1,958,699
Case 4 (Outage: 6th hour)	1,958,315	0	1,958,315
Case 3 (Outage: 20th hour)	1,959,691	145,663	2,105,354
Case 4 (Outage: 20th hour)	1,959,539	0	1,959,539
Case 3 (Outage: 24th hour)	1,959,475	33,451	1,992,926
Case 4 (Outage: 24th hour)	1,958,434	0	1,958,434

Figures 42, 44, and 46 show the hourly generation output, load shedding, and system load profile for Case 3. Figures 43, 45, and 47 show the hourly generation output, load shedding, energy storage output, and system load profile for Case 4. The left-hand vertical axis on the graphs applies to the load line (in yellow) and the generation-output line (in blue); the right-hand vertical axis on the graph applies to the energy-storage-output line (in orange) and the load-shedding line (in gray).

Figure 42: Generation Output (PG), Hourly Load Profile (Load), Energy Storage Output (PE), and Load Shedding (LS) of Case 3 (Outage at 6th Hour)

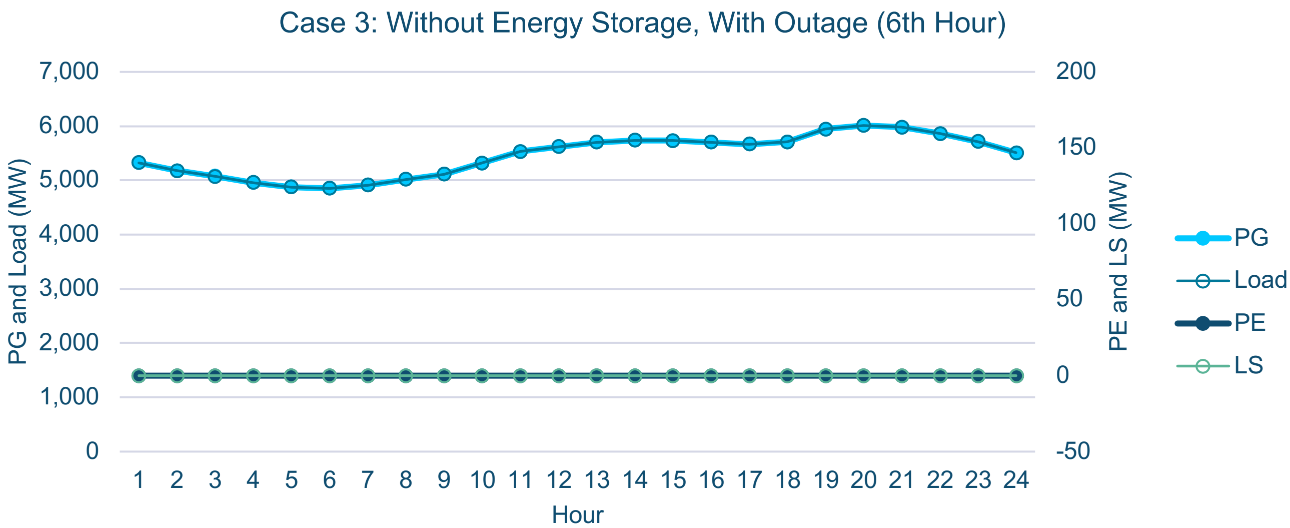
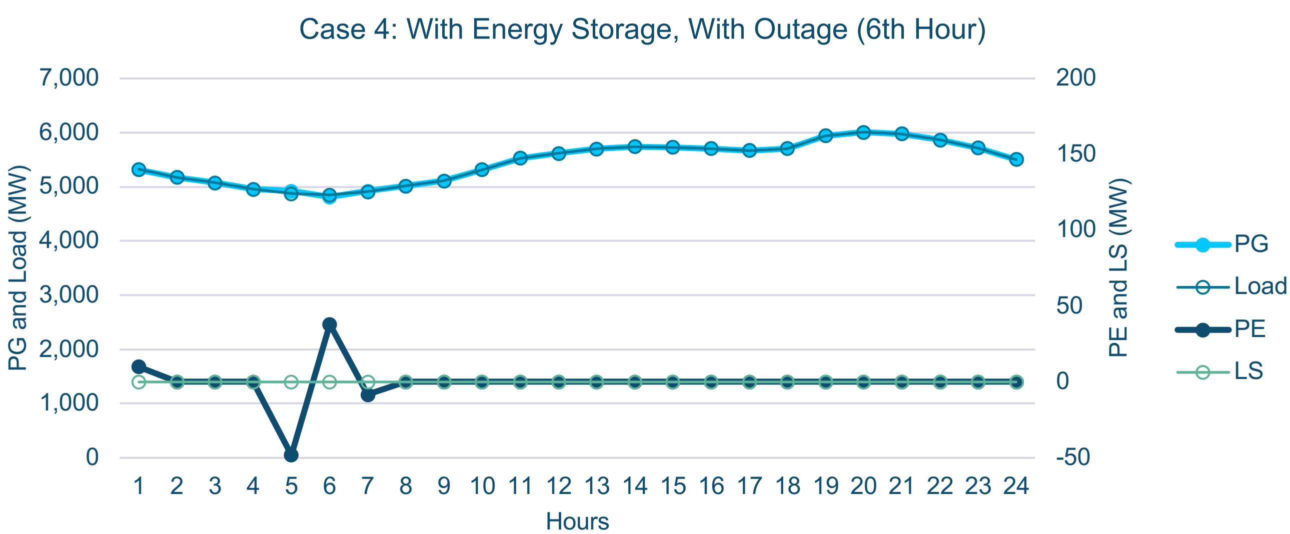


Figure 43: Generation Output (PG), Hourly Load Profile (Load), Energy Storage Output (PE), and Load Shedding (LS) of Case 4 (Outage at 6th Hour)



When the islanding outage occurred at the 6th hour (see Figures 42 and 43), the system without energy storage experienced a load-shedding cost of $130, while the system with energy storage did not experience a load-shedding cost. For Case 4, the energy storage was charged at the 5th hour and discharged at the 6th hour. By comparing Cases 3 and 4, the savings accrued by using energy storage were determined to be $384. The factors that impacted the savings were the strategic timing of charging in low load-demand hours and discharging at the time of the event.

Figure 44: Generation Output (PG), Hourly Load Profile (Load), Energy Storage Output (PE), and Load Shedding (LS) of Case 3 (Outage at 20th Hour)

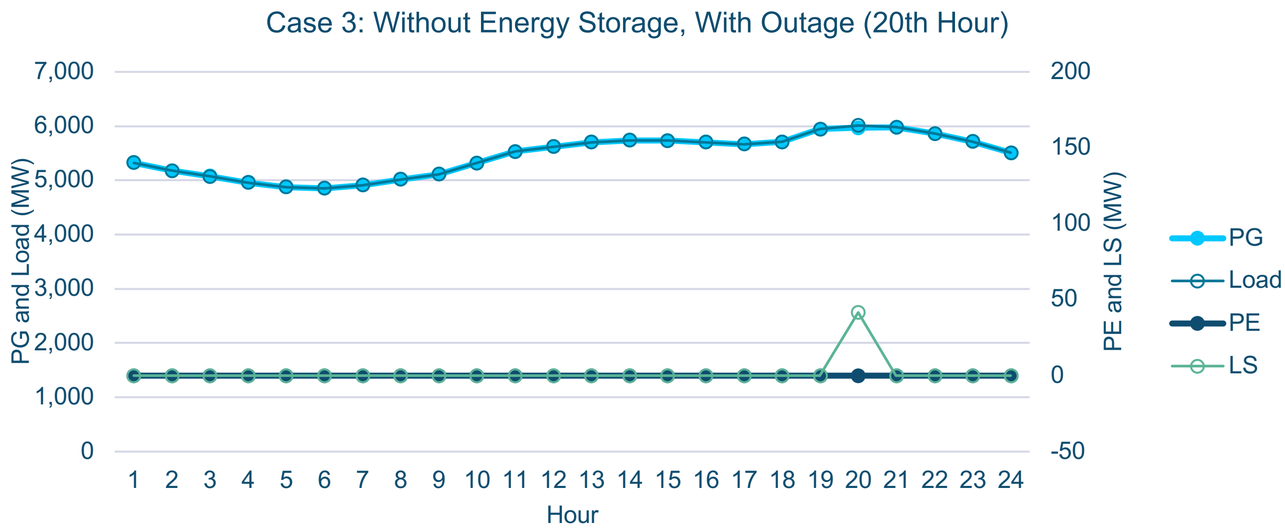
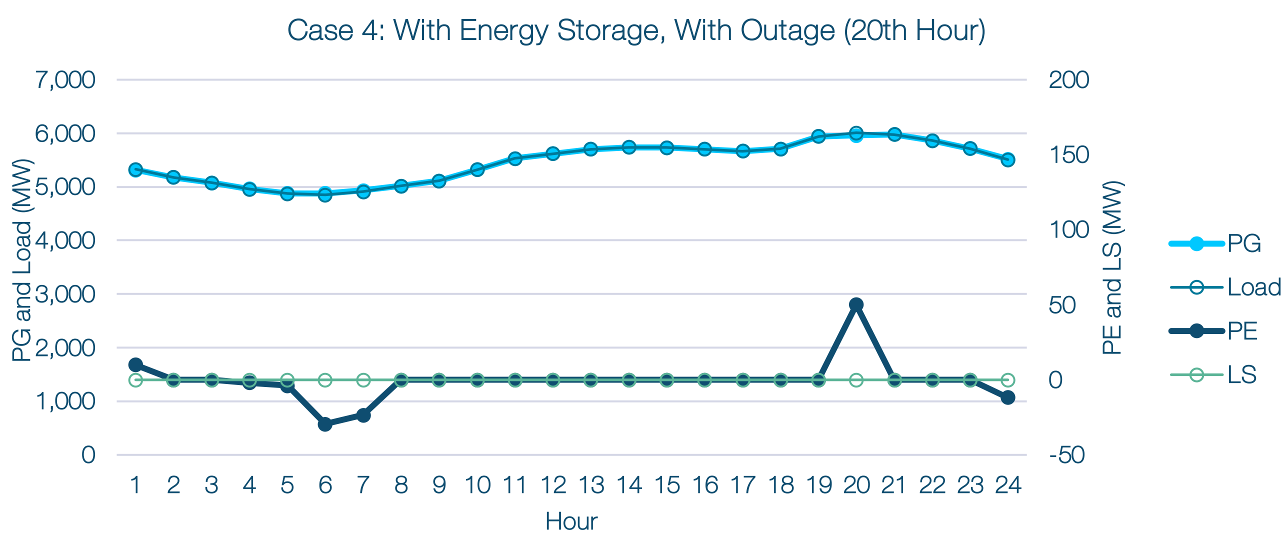


Figure 45: Generation Output (PG), Hourly Load Profile (Load), Energy Storage Output (PE), and Load Shedding (LS) of Case 4 (Outage at 20th hour)



When the islanding outage occurred at the 20th hour (see Figures 44 and 45), the system without energy storage experienced a load-shedding cost of $145,663, and the system with energy storage did not experience a load-shedding cost. For Case 4, the energy storage was charged from the 4th to 7th hour and discharged at the 20th hour. Due to constraints, the energy storage is also charged at the 24th hour and discharged at the 1st hour when generation costs are high. By comparing Cases 3 and 4, the savings accrued by using energy storage were determined to be $145,815. The factors that impacted the savings were the strategic timing of charging in low load-demand hours and discharging in high load-demand hours.

Figure 46: Generation Output (PG), Hourly Load Profile (Load), Energy Storage Output (PE), and Load Shedding (LS) of Case 3 (Outage at 24th hour)

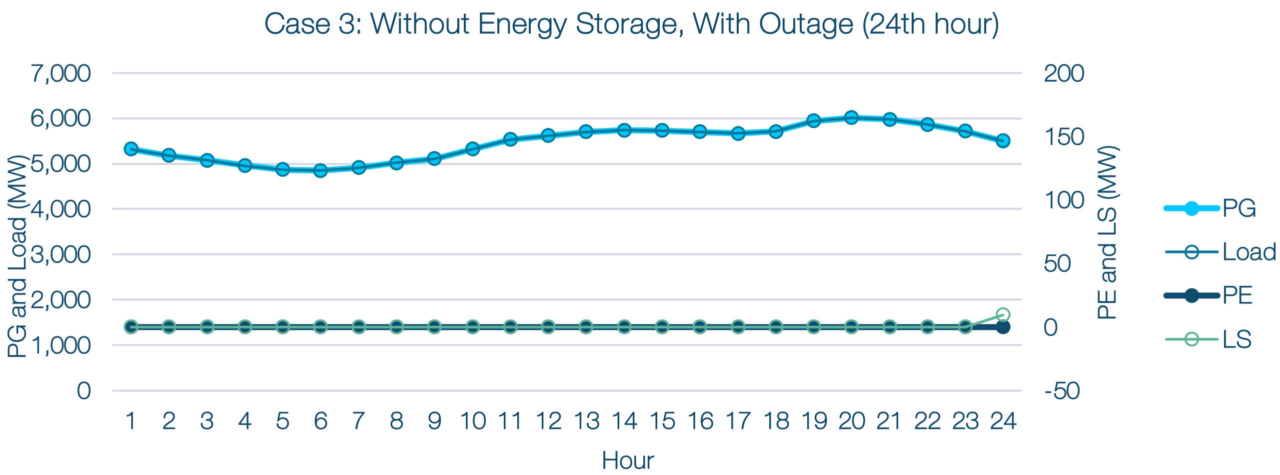
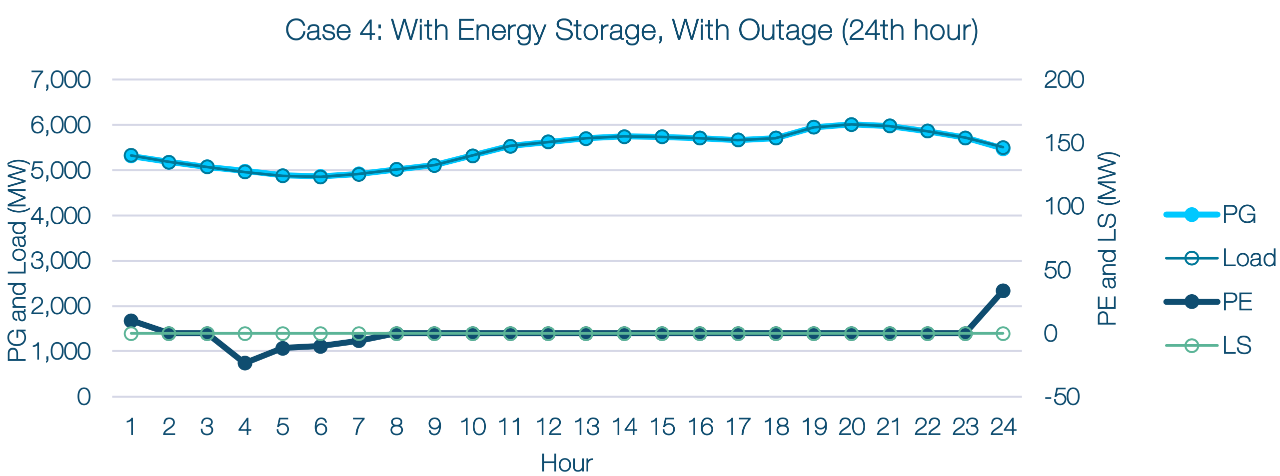


Figure 47: Generation Output (PG), Hourly Load Profile (Load), Energy Storage Output (PE), and Load Shedding (LS) of Case 4 (Outage at 24th hour)



When the islanding outage occurred at the 24th hour (see Figures 46 and 47), the system without energy storage experienced a load-shedding cost of $33,451, and the system with energy storage did not experience a load-shedding cost. For Case 4, the energy storage was charged from the 4th to 7th hour and discharged at the 24th hour. By comparing Cases 3 and 4, the savings accrued by using energy storage were determined to be $34,492. The factors that impacted the savings were the strategic timing of charging in low load-demand hours and discharging in high load-demand hours.

Discussion of Results

Energy storage benefits depend on the time of day that outages occur. The benefits of energy storage were the greatest when the islanding outage occurred at the highest load-demand hour of the day (i.e., the 20th hour). This result is due to the potential for the energy storage to relieve a large load loss. Energy storage was the least beneficial to the power system when the islanding outage occurred at the lowest load-demand hour of the day (i.e., the 6th hour). The savings generated from each case are shown in Table 25.

Table 25: Energy Storage Savings under Normal and Outage Conditions

System Condition	Energy Storage Saving ($)
Normal Condition	85
Outage: 6th hour	384
Outage: 20th hour	145,815
Outage: 24th hour	34,492

3. Economic Analysis

The following sections present results from a economic analysis showing the economic impact of a major weather event due to loss of electricity (e.g., customers without power despite being miles away from a hurricane) and of current grid-resiliency investments. Energy storage could become a portion of the allocated investment for grid resiliency in order to provide future reductions in loss of power for customers miles away from a major weather event. Some grid-resiliency efforts can be seen as insurance (such as building platforms for transformers and other equipment to prevent flood damage) because they do not affect the daily power system operations. If energy storage were to be included in such efforts, it would provide power on a daily basis and create income, in addition to being an invaluable resource in the event of a major weather event.

Economic Loss Due to Power Outages

Data from the U.S. Energy Information Administration show that weather-related outages have increased significantly since 1992 [34]. The United States suffered $11 billion in weather disasters in 2012, which was the second-most for any year on record, behind 2011. Over the 2003-2012 period, weather-related outages are estimated to have cost the U.S. economy an inflation-adjusted annual average of $18 billion to $33 billion [34]. Annual costs fluctuate significantly and are greatest in the years of major weather events. The costs of outages take various forms, such as lost output and wages, spoiled inventory, delayed production, inconvenience, and damage to the electric grid.

Utilities can be either publicly owned, investor-owned, or cooperatives. Most customers are served by investor-owned utilities [74]. The economic loss due to power outages during Hurricane Katrina caused the investor-owned utility to file for bankruptcy. Restoration costs ranged from $260 million to $325 million, and the loss of customer revenue was estimated at $147 million [75]. After Hurricane Rita, Entergy and the utilities operating in the affected areas of Texas, Louisiana, and Mississippi reported that they would need $2.5 billion in assistance [76].

Several studies have estimated the total cost of power outages in the United States based on estimates of utility customers' value of service reliability [77]. Estimates of annual cost of power outages are shown in Table 26.

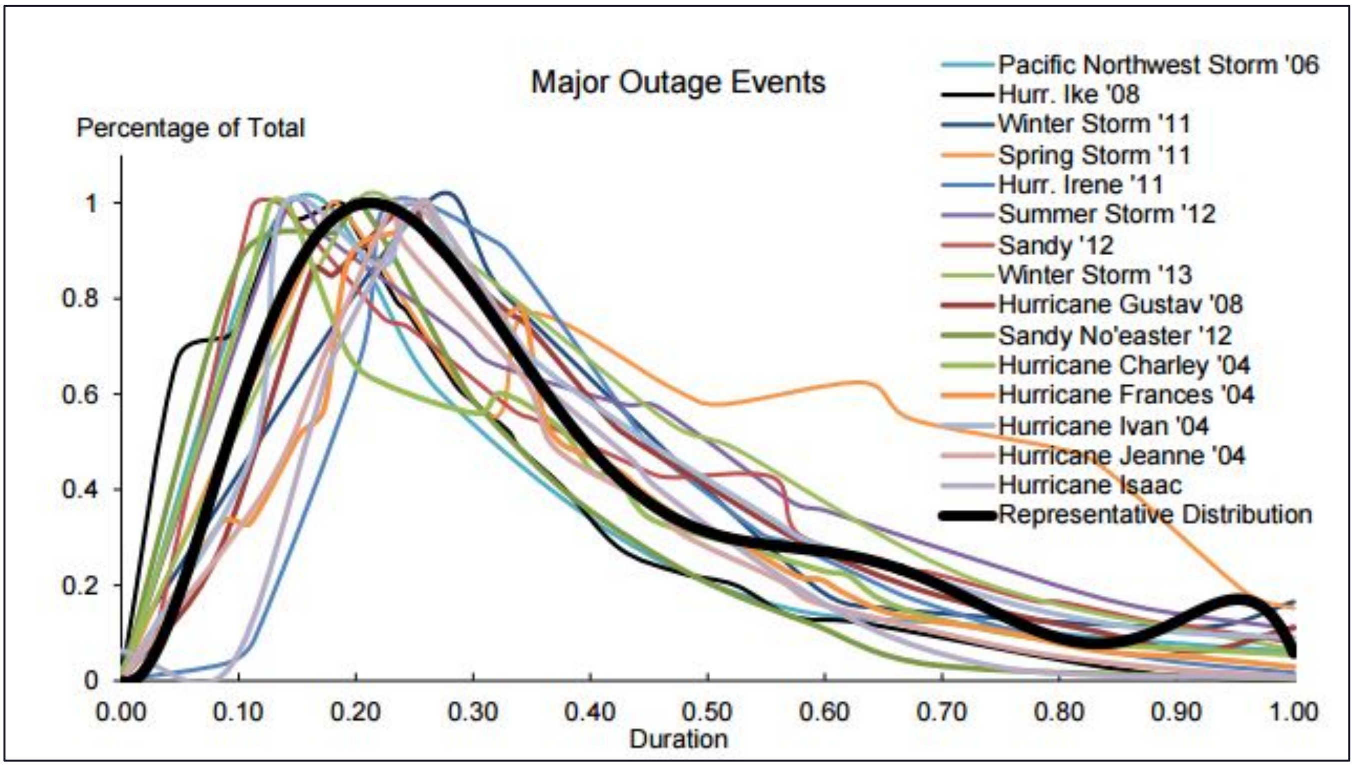
Table 26: Annual Cost of Power Outages [34]

Source	Estimate (in Billions 2012 $)	Year Published
All Outages		
Swaminathan and Sen **[78]**	59	1998
Primen **[79]**	132-209	2001
LaCommare and Eto **[80]**	28-169	2005
Weather-Related Outages		
Campbell (CRS) **[81]**	25-70	2012

In 2012, the Congressional Research Service estimated that the inflation-adjusted annual cost of weather-related outages in the United States was between $25 billion and $70 billion [81]. The calculations use prior estimates of the total cost of outages, outage duration, and the fraction of outages due to weather.

The following estimates are based on value of service (VOS) data that were originally collected by major electric companies using customer surveys and power outage data between 2003 and 2012 from the U.S. Department of Energy [34]. The U.S. Department of Energy tracks the cause, duration, and number of customers affected for each power outage reported in a given year. Figure 48 shows the distributions of customer power outages due to 15 major storms occurring between 2004 and 2012. All of the storm-outage profiles resemble one another. First, there is a sharp rise in the number of outages in the first few hours of the event. Then the number of affected customers peak in the first 15% to 25% of the total duration. Next, the majority of power is restored relatively quickly. Finally, substantial amounts of customers remain without power. The representative profile that was created from these 15 events was applied to all power outages caused by weather.

Figure 48: Major Outage Events, 2003-2012 [34]



Annual power outage costs, adjusted for inflation, ranged from $18 billion to $33 billion during the 2003-2012 period. The costs range considerably by year because large storms dominate the cost estimates. The estimates are shown in Table 27.

Table 27: Cost of Weather-Related Outages [34]

Year	Estimated Cost of Weather-Related Outages (in Billions 2012 $)
2003	14-16
2004	14-27
2005	14-27
2006	23-43
2007	5-10
2008	40-75
2009	8-14
2010	13-25
2011	19-36
2012	27-52

These estimates account for costs associated with lost output and wages, spoiled inventory, inconvenience, and cost of restarting industrial operations. Between 20% and 25% of the annual cost of weather-related power outages are due to lost output [34].

Cost of Current Resiliency Activities

As mentioned in the previous section of the report, the most common resiliency activity reported by utilities is pole inspection and maintenance. The most notorious source of damage to electric utility-pole infrastructure is hurricane force winds [34]. Much of this danger can be mitigated or eliminated by proper maintenance and control of vegetative overgrowth. Still, the primary hardening strategy is to upgrade distribution and transmission poles by size, strength, and material. Traditionally, this strategy has been done by investing in larger, stronger, and more expensive wooden utility poles. Recently, however, there has been a growing trend of replacing wooden utility poles with steel, concrete, and composite alternatives [34].

Since 2006, Florida Power and Light Company has invested more than $2.7 billion to strengthen its electric system and make it more resilient to severe weather [82]. Each year, the company inspects more than 150,000 poles, clears vegetation from 15,000 miles of lines, and strengthens more than 700 main power lines.

According to the Florida Power and Light Company's Distribution Reliability Report of 2015, the cost of its distribution pole inspection program was $73 million, which included inspection and remediation costs for wood and concrete poles [82]. The transmission poles and structures cost $1.4 million to inspect and $30.2 million to follow up on work identified from the 2015 inspections [82]. The goal of Florida Power and Light Company's vegetation management program is to clear vegetation from the vicinity of distribution facilities and equipment [82]. The cost of this program in 2015 is shown in Table 28.

Table 28: Vegetation Management Costs, 2015

Cost (in Millions $)	Feeder Miles					Lateral Miles
		Cycle	Mid-Cycle	Total		Cycle
62.90		4,209	7,218	11,427		3,817

Other programs used by Florida Power and Light Company to harden its infrastructure are shown in Table 29.

Table 29: Reliability Programs of Florida Power and Light Company [82]

Program	Program Description	2016 Budget (in Millions $)
Distribution Automation/Smart Grid	Install and maintain distribution automation devices. This program includes automated feeder switches, automated lateral switches and fault current indicators.	183.50
Priority Feeders (Including Inspections)	Reduce the number of customers experiencing multiple amounts of interruptions and momentaries by identifying and correcting feeders experiencing the highest number of events and/or customers interrupted.	75.10
Vegetation Management	Integrated program designed to minimize tree- and vine-related interruptions.	64.70
System Expansion	Provide the necessary feeder capacity to serve all customers during normal and emergency periods and install the infrastructure necessary to support system contingency.	48.50
Cable Lateral	Reduce the number of direct buried lateral cable failures and reduce customer interruptions.	45.90
Handhole Inspections/ Pad-Mounted Transformers	Inspection/remediation of non-compliant conditions. The purpose of this program is to maintain pad-mounted transformer security.	20.30
Submarine Cable	Reduce the number of submarine feeder cable failures and reduce customer interruptions.	20.00
Outlier Devices	Address lateral or OCR's with three or more interruptions in a given year.	12.90
RA Switch Replacement	Proactively replace RA switches in order to enhance system operations and reliability.	7.50
Cable Feeder	Reduce the number of direct buried feeder cable failures and reduce customer interruptions.	7.20
Overhead Line Inspection and Repairs	Conduct a visual and/or infrared inspection of the OH feeder infrastructure and thus reduce overhead interruptions.	7.00
Momentary Outliers	Address worse-performing busses and high momentary feeders.	6.40
OCR Replacement	Replace oil circuit reclosers with electronic reclosers.	3.90
Vault Inspections and Repairs (Not Including RA Switches)	Inspect vaults and Powell-Esco Switches. Program will mitigate vault interruptions and will help to identify any issues that need to be addressed before an interruption occurs.	3.70
Small-Wire Replacement	Replace small conductor feeder (less than #1/0) with larger conductor feeder in circuits with multiple small-wire interruptions. This does not include feeder mileage past radial OCRs.	2.60
VAR Management (Installations and Maintenance)	Install, relocate, maintain, and control distribution capacitor banks. This program will help maintain or improve power factor performance and improve system efficiency, reliability, and quality of service voltage to our customers.	2.40
Customer Impact	Projects targeted to improve reliability for specific customers or geographic areas.	2.30

Figure S6: Solar Microgrid [86]

For the first time in a practical and self-sustaining application, Duke Energy is installing an islanded microgrid, as shown in Figure S6, that collects solar energy and stores it for use at the Great Smoky Mountains National Park. The islanded microgrid will power a radio tower, and the four miles of power lines that currently feed this tower will be permanently removed. “They did the numbers and found it was less costly to build versus replacing four miles of transmission line up a rugged terrain,” said Jack Floyd, an engineer with the North Carolina Public Staff, the state-sanctioned ratepayer advocate [85]. The islanded microgrid will also cost less to maintain than existing power lines and eliminate the risk of power outages, which could take days to repair in mountainous terrain. Duke Energy plans to bring this same technology, as well as its reliability and cost-effectiveness, to consumers in the Asheville area in the near future.

4. Conclusion

Use Case 5 investigated the resiliency of the grid in the southeastern United States and if and how energy storage can possibly contribute toward the reliability and resiliency of the energy grid in the region. While conventional response to improve grid resiliency against natural disasters and severe weather events has primarily focused on upgrading infrastructure and limiting outages, this analysis showed that using the energy storage option in the Southeast can limit the duration and reach of large-area outages due to weather events by enabling the grouping of central and distributed generation resources into stable functioning islands while the interconnecting system is repaired. Financial benefits of pursuing the energy storage option in the Southeast include avoidance of lost economic output (primary stack) and operation of generation assets that would otherwise be stranded (secondary stacks).

Data from past events were used to determine the risks imposed to energy grids in the Southeast. Of all natural disasters and severe weather events discussed, hurricanes are the most harmful to power grids in the Southeast, as hurricanes have caused more widespread and longer-lasting power outages than all other severe weather events. Although seismic activity in the region may have the potential to be more catastrophic in terms of the severity and duration of grid failures, there are no historical data to project the risks of or remedies to earthquakes.

The power-system simulation revealed that energy storage is economically beneficial even if a power outage does not occur. The cost-production model indicated that the level of benefits of energy storage is dependent on the time of day of a power outage. Energy storage was the most beneficial to the power system when the islanding outage occurred at the highest load-demand hour of the day. Energy storage was the least beneficial to the power system when the islanding outage occurred at the lowest load-demand hour of the day.

Current efforts to harden infrastructure and build resiliency against natural hazards do not entirely protect the grid. The average duration of outages caused by hurricanes is 11 days. The economic loss due to power outages, such as lost output and wages, spoiled inventory, delayed production, inconvenience and damage to the electric grid, averages between $18 billion and $33 billion. Florida Power and Light Company spends millions of dollars per year on reliability programs to harden its energy infrastructure. Considering that this is just one utility company in one of the 12 states in the Southeast, it is apparent that the money spent on reliability programs in the region is significant. Although investing in hardening practices is and will remain necessary, supplementing these practices with stored energy and islanding would potentially improve resiliency and decrease the duration of future power outages. To accomplish this wide public benefit, it will be necessary for change in the utilities' willingness to operate in an islanded mode in the event of a natural disaster. This approach is a policy reversal from the current utility perspective that should be pursued.

VI. Conclusion

The outputs of the ESCT computed for Use Cases 1-4 inform the major conclusions of this report. These results are quantitative and extensively reported in the main portion of this document. But an overarching assessment of the data leads to findings listed here.

Capital deferrals for utility infrastructure improvements to support load growth from new economic development projects are significant enough to pay for a battery-storage facility located near the end of major transmission lines. This opportunity can lead to advantages to communities that might otherwise lose a major economic development opportunity because of delays in upgrading or adding new transmission lines—delays that, in more urban or ecologically sensitive areas, can be considerable (i.e., years). In contrast, the relative size of the battery energy storage project computed for Use Case 1 would allow the installation of the project with little or no impact on the community and thus would be completed rapidly and within budget.

The recent total eclipse of the sun that crossed the North American continent on August 21, 2017, highlighted a growing recognition that integration of intermittent renewable energy has limits. The political climate of the Southeast requires market-based renewable energy, which means political limits on the subsidy that ratepayers will accept for renewable energy portfolios. Nevertheless, there is market pull from customers such as Walmart Inc., as well as others, for utilities to include renewable energy in the generation mix within the Southeast. Use Case 2 demonstrated that energy storage is an economically feasible option in the North Carolina service area to help "firm" the high rate of solar energy penetration in the state while reducing the need to build natural gas-fired fossil fuel plants.

A feature unique to the Southeast is the lack of wind-based renewable energy. However, plentiful wind energy in West Texas and in the Midwest could be imported with existing or planned transmission systems. However, much of this energy is available “off peak” and thus would be more valuable and provide more Southeastern energy needs if off-peak wind energy could be stored in bulk energy storage between the western sources and the eastern loads. An advantageous trend is examined in Use Case 3 where recent increases in the supply of natural gas in the Louisiana and East Texas region has reduced the need for seasonal storage of natural gas. At the same time, Louisiana is experiencing among the highest rates of electric load growth in the nation due in part to this ready supply of natural gas for new industrial development and expansion. Use Case 3 shows that billions of dollars in new power plant construction could be deferred by repurposing existing natural gas storage facilities into bulk energy storage facilities based on compressed air energy storage technology. In the Use Case 3 analysis, existing storage sites are identified in geographically ideal locations between wind generation assets and new electrical loads and are shown to have enormous economic potential for the Southeast.

On August 23, 2017, the U.S. Department of Energy released the Staff Report to the Secretary on Electricity Markets and Reliability. In that report, a variety of economic factors were cited to explain the closure of numerous older coal-fired generation plants around the country, especially in the Southeast. A typical result of such closures are realignments of the transmission system and possibly new generation that represents enormous new capital costs. It is hypothesized in Use Case 4 that one such planned closure announced by Duke Energy could be better managed with a modest 50 MW energy storage project based on battery technology or above-ground compressed air storage. However, despite the opportunity for capital deferral as well as other stacked benefits from ancillary services, all technology options resulted in net negative stacked benefits as calculated by the ESCT, and thus an economically viable solution to the planned closure of the coal plant based on utility-scale energy storage was not found.

In Use Case 5, a long-term opportunity is proposed that will allow a transformational change in the way the grid can respond to infrequent but high-impact natural perils. Modest amounts of utility-scale energy storage distributed in strategically selected ways across a 21st-century electric grid, with both conventional generation and significant amounts of distributed energy resources, could allow ad-hoc networks of power islands to maintain service over large areas isolated from each other by major damage to interconnecting infrastructure. It is shown in this report that billions of dollars are being invested to harden the power grid throughout the Southeast. It is proposed that some of these investments can be used as a kind of “insurance premium,” which will augment the stacked benefits of energy storage when combined with conventional capital investments intended to improve the operation of the power grid as considered in Use Cases 1, 2, and 4. This “insurance premium” could be a critical factor in determining whether certain energy storage projects yield positive net stacked benefits.

Overall, it was found that of the four use cases analyzed using the stacked benefits method, three have net positive economic benefits in locations within the service areas of the four major utilities defining the scope of the Southeast in this study. The most attractive was Use Case 3, which shows that an opportunity unique to the Southeast exists to enable imports of renewable energy based on wind from western locations, where a sufficient amount of wind energy is generated at night to be time-shifted for use by the rapidly growing load centers in the industrial regions in and around Louisiana.

VII. References

[1] J. Ellison, D. Bhatnagar, C. Black and K. Jenkins, "Southern Company energy storage study: A study for the DOE Energy Storage Systems Program," Sandia National Laboratories, Albuquerque, 2013.

[2] J. Eyer and G. Corey, "Energy storage for the electricity grid: Benefits and market potential assessment guide," Sandia National Laboratories, Albuquerque, 2010.

[3] J. Eyer, "Electric utility transmission and distribution upgrade deferral benefits from modular electricity storage: A study for the DOE Energy Storage Systems Program," Sandia National Laboratories, Albuquerque, 2009.

[4] U.S. Energy Information Administration, "U.S. electric system operating data," [Online]. Available: https://www.eia.gov/beta/realtime_grid. [Accessed 13 June 2017].

[5] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. B. Chen, A. L. Cotter, D. T. Bradshaw and W. D. Gauntlett, "DOE/EPRI electricity storage handbook in collaboration with NRECA," Sandia National Laboratories, Albuquerque, 2015.

[6] Lazard, "Lazard's levelized cost of storage–Version 2.0," New York, 2016.

[7] H. Shaalan, "Generation of electric power," in *Handbook of Electric Power Calculations*, New York, McGraw-Hill, 2001, pp. 8.1-8.38.

[8] U.S. Energy Information Administration, "Levelized cost and levelized avoided cost of new generation resources in the Annual Energy Outlook," 2015.

[9] J. St. John, "PG&E's 75MW Energy storage procurement to test flywheels, zinc-air batteries," *GreenTech Media,* 3 December 2015.

[10] M. M. Hand, S. Baldwin, E. DeMeo, J. M. Reilly, T. Mai, D. Arent, G. Porro, M. Meshek and D. Sandor, "Renewable electricity futures study," The National Renewable Energy Laboratory, Golden, 2012.

[11] G.E. Energy, "Western wind and solar integration study," The National Renewable Energy Laboratory, Golden, 2010.

[12] Solar Energy Industries Association, "Top 10 solar states," 2017.

[13] Georgia Power, "Advanced solar initiative," [Online]. Available: https://www.georgiapower.com/about-energy/energy-sources/solar/advanced-solar-initiative.cshtml. [Accessed 12 April 2017].

[14] Georgia Power, "2016 integrated resource plan and application for decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT," 2016.

[15] Green Power EMC, "Green Power EMC: Renewable energy," 2017. [Online]. Available: http://www.greenpoweremc.com/. [Accessed 12 April 2017].

[16] J. Durkay, "State renewable portfolio standards and goals," National Conference of State Legislatures, 1 August 2017. [Online]. Available: http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx. [Accessed 31 August 2017].

[17] K. Shallenberger, "North Carolina governor signs solar bill, targets wind moratorium with executive order," *Utility Dive,* 27 July 2017.

[18] U.S. Energy Information Administration, "Capital cost estimates for utility scale electricity generating plants," 2016.

[19] U.S. Energy Information Administration, "Wind turbines provide 8% of U.S. generating capacity, more than any other renewable source," *Today in Energy,* 2 May 2017.

[20] U.S. Energy Information Administration, "State profile and energy estimates," 2014. [Online]. Available: https://www.eia.gov/state/rankings/?sid=LA. [Accessed 22 July 2017].

[21] H. Chen, X. Zhang, J. Liu and C. Tan, "Compressed air energy storage," in *Energy Storage - Technologies and Applications*, InTech, 2013, pp. 101-112.

[22] H. Ibrahim, A. Ilinca and J. Perron, "Energy storage systems—Characteristics and comparisons," *Renewable and Sustainable Energy Reviews,* vol. 12, no. 5, pp. 1221-1250, 2008.

[23] Y.-M. Kim, J.-H. Lee, S.-J. Kim and D. Favrat, "Potential and evolution of compressed air energy storage: Energy and exergy analyses," *Entropy,* vol. 14, no. 8, pp. 1501-1521, 2012.

[24] BINE, "Compressed air energy storage power plants," *Projekt-Info,* pp. 1-4, May 2007.

[25] Energy Storage Association, "Compressed air energy storage (CAES)," [Online]. Available: http://energystorage.org/compressed-air-energy-storage-caes. [Accessed 22 June 2017].

[26] U.S. Energy Information Administration, "Henry Hub Natural Gas Spot Price," 6 December 2017. [Online]. Available: https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm. [Accessed 12 December 2017].

[27] E. Bozzolani, "Techno-economic analysis of compressed air energy storage systems," Cranfield University, Cranfield, 2010.

[28] Electric Power Research Institute, "Electricity energy storage technology options: A white paper primer on applications, costs, and benefits," Palo Alto, 2010.

[29] R. Wiser and M. Bolinger, "2015 Wind technologies market report," U.S. Department of Energy, 2016.

[30] Duke Energy, "Coal plant decommissioning program," [Online]. Available: https://www.duke-energy.com/our-company/about-us/coal-plant-decommissioning-program. [Accessed 1 May 2017].

[31] Duke Energy, "Duke Energy Progress gains approval to transition to a smarter, cleaner energy future at the Asheville Plant," 29 February 2016. [Online]. Available: https://news.duke-energy.com/releases/duke-energy-progress-gains-approval-to-transition-to-a-smarter-cleaner-energy-future-at-the-asheville-plant. [Accessed 9 March 2017].

[32] D. M. Ward, "The effect of weather on grid systems and the reliability of electricity supply," *Climatic Change,* vol. 121, no. 1, p. 103–113, 2013.

[33] A. Sharifi and Y. Yamagata, "Principles and criteria for assessing urban energy resilience: A literature review," *Renewable and Sustainable Energy Reviews,* vol. 60, pp. 1654-1677, 2016.

[34] Executive Office of the President, "Economic benefits of increasing electric grid resilience to weather outages," Washington, 2013.

[35] U.S. Department of Energy, "Grid energy storage," 2013.

[36] N. Hatziargyriou, I. Margaris, I. Stavropoulou, S. Papathanassiou and A. Dimeas, "Noninterconnected island systems: The Greek case," *IEEE Electrification Magazine,* vol. 5, no. 2, pp. 17-27, 2017.

[37] U.S. Department of Energy, "Hardening and resiliency: U.S. energy industry response to recent hurricane seasons," 2010.

[38] A. B. Smith, "2016: A historic year for billion-dollar weather and climate disasters in U.S.," National Oceanic and Atmospheric Administration, 2017.

[39] J. Wirfs-Brock, "Data: Explore 15 Years Of Power Outages," 18 August 2014. [Online]. Available: http://insideenergy.org/2014/08/18/data-explore-15-years-of-power-outages/. [Accessed 18 April 2017].

[40] R. H. Grumm, "Southern Heavy rain and floods of 8-10 March 2016," 4 April 2016. [Online]. Available: http://cms.met.psu.edu/sref/severe/2016/09Mar2016.pdf. [Accessed 18 May 2017].

[41] National Oceanic and Atmospheric Administration, "Billion-dollar weather and climate disasters: Table of events," 2017. [Online]. Available: https://www.ncdc.noaa.gov/billions/events/US/2000-2017. [Accessed 17 May 2017].

[42] U.S. Department of Energy, "Tuesday Evening, March 08, 2016," *Energy Assurance Daily,* pp. 1-4, 8 March 2016.

[43] U.S. Department of Energy, "Wednesday evening, March 09, 2016," *Energy Assurance Daily,* pp. 1-4, 09 March 2016.

[44] U.S. Department of Energy, "Thursday evening, March 10, 2016," *Energy Assurance Daily,* pp. 1-5, 10 March 2016.

[45] U.S. Department of Energy, "Monday evening, April 18, 2016," *Energy Assurance Daily,* pp. 1-5, 18 April 2016.

[46] U.S. Department of Energy, "Tuesday evening, April 19, 2016," *Energy Assurance Daily,* pp. 1-4, 19 April 2016.

[47] U.S. Department of Energy, "Wednesday evening, April 20, 2016," *Energy Assurance Daily,* pp. 1-4, 20 April 2016.

[48] R. Cleetus, "Overwhelming risk: Rethinking flood insurance in a world of rising seas," Union of Concerned Scientists, Cambridge, 2013.

[49] J. McNamara, S. Clemmer, K. Dahl and E. Spanger-Siegfried, "Lights out? Storm surge, blackouts, and how clean energy can help," Union of Concerned Scientists, Cambridge, 2015.

[50] Aon Benfield, "United States April & May 2011 severe weather outbreaks," 2011.

[51] Federal Emergency Management Agency, "Spring 2011 tornadoes: April 25-28 and May 22," 2012.

[52] U.S. Department of Energy, "2011 Spring storm," [Online]. Available: https://www.oe.netl.doe.gov/named_event.aspx?ID=34. [Accessed 17 May 2017].

[53] kwright100, "Tornado risk by affiliate service area," 7 December 2016. [Online]. Available: http://www.arcgis.com/home/item.html?id=6f686052d01546a8b23d6631171b03c7. [Accessed 13 May 2017].

[54] U.S. Department of Energy, "Tuesday evening, December 10, 2013," *Energy Assurance Daily,* pp. 1-4, 10 December 2013.

[55] U.S. Department of Energy, "Winter storm situation report #1: December 6, 2013 (3:00 PM EST)," 2013.

[56] U.S. Department of Energy, "Wednesday evening, February 12, 2014," *Energy Assurance Daily,* pp. 1-5, 12 February 2014.

[57] U.S. Department of Energy, "Thursday evening, February 13, 2014," *Energy Assurance Daily,* pp. 1-5, 13 February 2014.

[58] U.S. Department of Energy, "Friday evening, February 14, 2014," *Energy Assurance Daily,* pp. 1-5, 14 February 2014.

[59] U.S. Department of Energy, "Southeast, Mid-Atlantic, Northeast winter weather situation report #2: February 13, 2014 (3:00 PM EST)," 2014.

[60] U.S. Department of Energy, "Southeast, Mid-Atlantic, Northeast winter weather wituation report #3: February 14, 2014 (3:00 PM EST)," 2014.

[61] Hurricanes: Science and Society, "2004-Hurricane Ivan," [Online]. Available: http://www.hurricanescience.org/history/storms/2000s/hurricaneivan/. [Accessed 13 May 2017].

[62] U.S. Department of Energy, "Hurricane Ivan," [Online]. Available: https://www.oe.netl.doe.gov/hurricanes_emer/ivan.aspx. [Accessed 17 May 2017].

[63] National Hurricane Center, "Hurricanes in history," [Online]. Available: http://www.nhc.noaa.gov/outreach/history/. [Accessed 18 May 2017].

[64] U.S. Department of Energy, "Hurricane Katrina," [Online]. Available: https://www.oe.netl.doe.gov/hurricanes_emer/katrina.aspx. [Accessed 17 May 2017].

[65] U.S. Department of Energy, "Hurricane Matthew Situation Reports October 2016," [Online]. Available: https://energy.gov/oe/downloads/hurricane-matthew-situation-reports-october-2016. [Accessed 17 May 2017].

[66] A. M. Avolio, H. Cheng, K. M. Fellows, A. Hisagi, J. R. Leahy, L. Mabry and A. Sutphen, "Assessing risk in a changing climate: Opportunities to improve hurricane response and mitigation policy in New Orleans," *The Evans School Review,* vol. 3, no. 1, pp. 84-97, 2013.

[67] Fair American Insurance and Reinsurance Company, "New Madrid Seismic Zone: Implications for insurers," New York, 2015.

[68] TennesseeHealth, "Peak horizontal acceleration with 2 % probability of exceedance in 50 years for conterminus U.S.," 16 September 2014. [Online]. Available: https://www.arcgis.com/home/item.html?id=c10143719986482fb1eb380d0ad166af#overview. [Accessed 21 August 2017].

[69] Rolypolyman, "United States power grid," 26 September 2008. [Online]. Available: https://commons.wikimedia.org/wiki/File:UnitedStatesPowerGrid.jpg. [Accessed 21 August 2017].

[70] R. Christie, "Power systems test case archive: 118 bust power flow test case," 1993. [Online]. Available: https://www2.ee.washington.edu/research/pstca/pf118/pg_tca118bus.htm. [Accessed 11 June 2017].

[71] Navigant Consulting, "Energy Storage Computational Tool," [Online]. Available: https://www.smartgrid.gov/recovery_act/analytical_approach/energy_storage_computational_tool.html. [Accessed 1 June 2017].

[72] Midcontinent Independent System Operator, "Evaluating energy offer cap policy," 2016.

[73] X. Luo, J. Wang, M. Dooner and J. Clarke, "Overview of current development in electrical energy storage technologies and the application potential in power system operation," *Applied Energy,* vol. 137, no. 1, pp. 511-536, 2015.

[74] American Public Power Association, "U.S. electric utility industry statistics (2015-2016 Annual directory and statistical report)," 2016.

[75] U.S. Department of Energy, "Comparing the impacts of the 2005 and 2008 hurricanes on U.S. energy infrastructure," 2009.

[76] Congressional Budget Office, "The macroeconomic and budgetary effects of Hurricanes Katrina and Rita: An update," Washington, 2005.

[77] M. J. Sullivan, M. Mercurio and J. Schellenberg, "Estimated value of service reliability for electric utility customers in the United States," Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, 2009.

[78] S. Swaminathan and R. K. Sen, "Review of power quality applications of energy storage systems," Sandia National Laboratories, Albuquerque, 1998.

[79] Primen, "The cost of power disturbances to industrial & digital economy companies," EPRI's Consortium for Electric Infrastructure for a Digital Society, 2001.

[80] K. H. LaCommare and J. H. Eto, "Cost of power interruptions to electricity consumers in the United States (US)," *Energy,* vol. 31, no. 12, pp. 1845-1855, 2005.

[81] R. J. Campbell, "Weather-related power outages and electric system resiliency," Congressional Research Service, 2012.

[82] Florida Power and Light Company, "2015 Florida Power and Light Company distribution reliability report," Juno Beach, 2016.

[83] Green Tech Media, "Duke Energy's $30 Million Investment in Battery Storage Is 'a Harbinger of Things to Come'," [Online]. Available: https://www.greentechmedia.com/articles/read/duke-energy-invests-30-million-in-battery-storage#gs.rpDcJ1Y. [Accessed 15 December 2017].

[84] Federal Emergency Management Agency, "Hurricane: Be Smart. Know Your Hazard," [Online]. Available: https://community.fema.gov/hazard/hurricane-en_us/be-smart?lang=en_US\. [Accessed 18 May 2017].

[85] E. Ouzts, "North Carolina regulators approve solar microgrid in Smokies," *Southeast Energy News,* 7 April 2017.

[86] J. Downey, "Duke Energy Plans solar-powered micro-grid at Great Smokey Mountains National Park," *Charlotte Business Journal,* 10 November 2016.

[87] J. Fallows, "Heavy industry in the Mississippi 'prairie'" Why are these factories here?," *The Atlantic,* 30 May 2014.

[88] J. M. Melillo, T. Richmond and G. W. Yohe, "Climate change impacts in the United States: The third national climate assessment," U.S. Government Printing Office, Washington, 2014.

[89] J. Downey, "Cypress Creek's new N.C. projects combine solar and storage," *Charlotte Business Journal,* 20 July 2017.

[90] Cardinal Gas Storage Partners, "Cadeville Gas Storage," 2017. [Online]. Available: http://www.cadevillegasstorage.com/index.php. [Accessed 9 August 2017].

VIII. Appendix A: Overview of Power Systems Software Developed by Mississippi State University and Entergy

A. Load Serving Tool

The purpose of the Load Serving Tool (LST) project is to determine the load serving capability at a particular location. The user defines a closed boundary region at a geographic location (what can be loosely called "circle") on the transmission system model maintained in the PowerWorld software. The MSU developed tool, LST, will then determine the load serving capability for that specified area based on a selected set of contingency criteria. The LST implementation involves automating Available Transfer Capability (ATC) and Security Constrained Optimal Power Flow (SCOPF), which are tools within PowerWorld, and increasing a user-specified amount of load until the load serving capability criteria are reached. A "results file" is created that documents the inputs to the LST graphical user interface (GUI) and the results after each ATC run and finally lists the load serving capability for the selected region.

The LST script works in the following manner. First, the base case must complete a successful run before the program enters a loop to increment the load inside a given region. The program will continue to loop until it determines the amount of load serving capability that can be realized.

The program will run ATC to ensure that there are no base-case violations. To check the base case, a violation is defined as a negative transfer limit value for a given limiting element and contingency. If there is a violation, the program will then run SCOPF->ATC repeatedly to see if all violations can be resolved. If any worst-case violation (with the same limiting element and contingency) appears more than once, the program will prompt the user that there is a problem with the base case.

Once there are no issues with the base case, the case will be saved with "_updated" appended to the case name. A loop will be implemented at this point to increment the load in the circle until a repeating transfer limit violation occurs (with the same limiting element and contingency), as in the manner described for the base case. A load increment, which consists of the sum of the "load increment" entered in the GUI plus the value of the transfer limit for the top violation in the previous ATC result, will be added to the circle. After the load is added, a power flow run will be executed to ensure there are no issues with the additional load. If no issues exist with the power flow, ATC will run to see if any violations exist. If there is a violation, the program will then run SCOPF->ATC repeatedly to see if all violations can be resolved. If any worst-case violation (with the same limiting element and contingency) appears more than once, the program cannot serve the incremented load, exits the loop, and outputs the last successful incremented load. If no violations exist, the case is again saved with "_updated" appended to the case name (this will be overwritten with each save), and the program continues with the next loop iteration.

Steps for Using the LST Program:

Step 1: Draw a selected region (circle) in a PowerWorld case and export the circle components as an auxiliary file.

i. Open a case in PowerWorld, select Edit Mode, then select the Draw tool > Select Region, choose the Polygon option, and choose “Touching” as shown in Figure A1. These steps will allow the user to draw a “circle” around a desired region. The “touching” feature allows PowerWorld to include anything touching the drawn polygon as a selected object.

ii. To end drawing the circle, double click anywhere, and the objects inside and touching the circle will be highlighted.

iii. The user will then right-click the selected objects and select “Create an Injection Group from Selection,” which will then need to be saved as an auxiliary or “.aux” file. After naming the file, the user will need to select “YES” on the pop-up to ensure that all necessary participation point data are included.

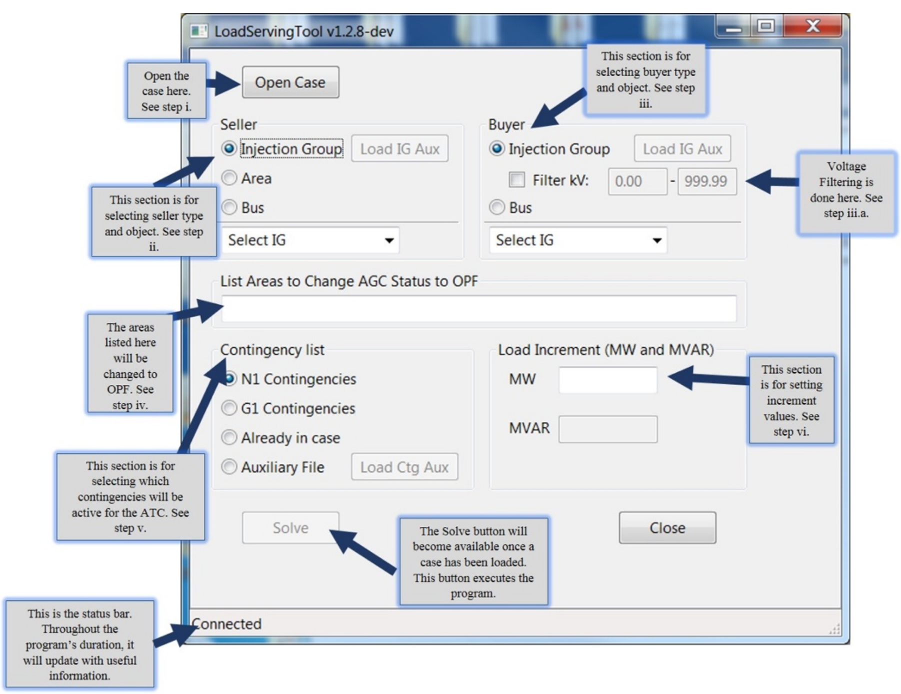
iv. Once the auxiliary file containing the circle has been saved, the user will then close PowerWorld.

Step 2: Run the Load Serving Tool

The user will run the LST python script. Upon running the script, the GUI shown in Figure A1 will appear.

*Note that when running LST.py with the same case, the previous LST Result and Log files for that case will be overwritten. To save your results, be sure to change the name of the result and log files or move them to a different directory.

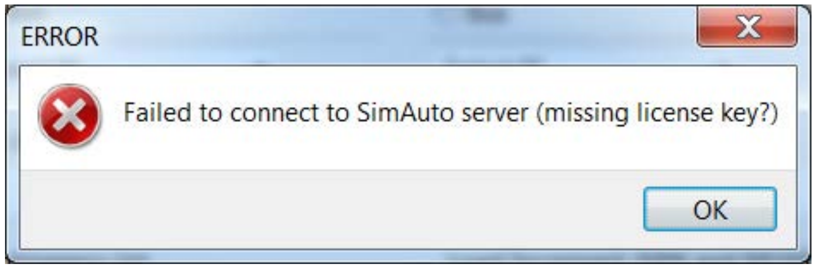
Figure A1: GUI for LST



i. When the user first runs the program, the "Open Case" button will be unavailable or "grayed out" while the program is connecting to PowerWorld via the SimAuto tool. "Connecting to SimAuto Server, please wait…" will appear in the status bar. Once the connection has been made, the status bar will change to "Connected," and the "Open Case" button will become available on the GUI.

*Note if using a hardware key for the PowerWorld software, please ensure that it is plugged in before trying to run the script, or the error shown in Figure A2 will appear.

Figure A2: Error When LST Fails to Connect to PowerWorld



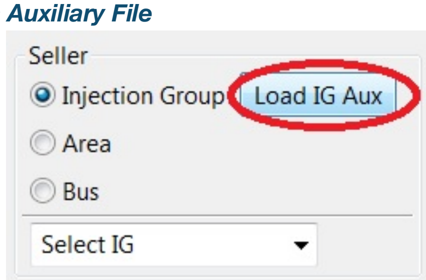
Once the "Open Case" button is available, the user will click it to open a file browser. The script will default to its directory location, but the user may browse to any directory to select the appropriate PowerWorld binary or "pwb" file. The only PowerWorld case format allowed for the script is pwb.

ii. Next, the user will select the "Seller Type." The seller would be the provider of power to the load within the circle. There are several different options for the seller. The user could select "Injection Group," "Area," or "Bus."

a. Injection Group – In order to select an injection group (IG), there should be an auxiliary file that contains the seller IG information. The user will have to perform two steps when selecting the IG option.

    i. Step 1 would be to click the "Load IG Aux" button to load the appropriate auxiliary file, as shown in Figure A3, that will contain the IG.

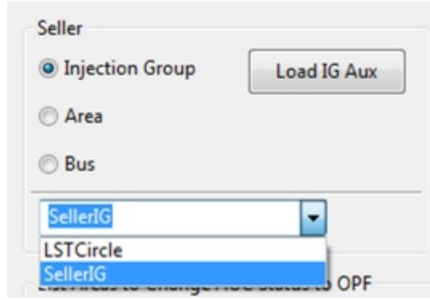
Figure A3: Select Seller's Auxiliary File



    ii. Once the file is chosen, step 2 requires the specific IG to be selected from the dropdown menu "Select IG," which will contain all injection groups found within the auxiliary file provided in step 1. This is shown in Figure A4.

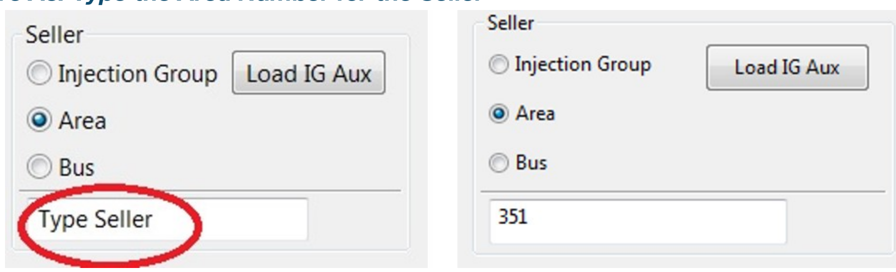
*Note: If an auxiliary file contains multiple IGs, all IGs will be listed in both buyer and seller dropdown menus after the file is processed. Any IGs already saved in the case will be available for selection from the dropdown menu.

Figure A4: Select Seller IG



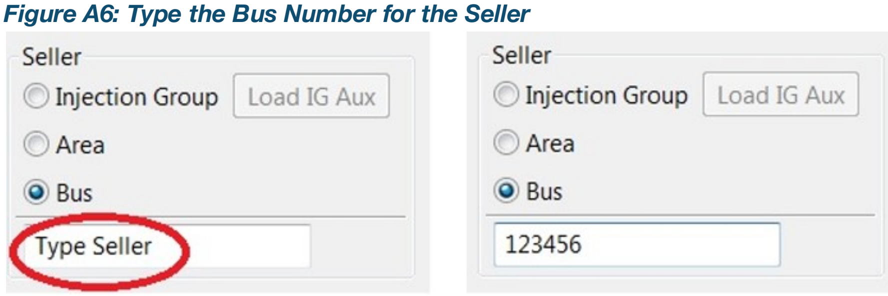
b. Area - If "Area" is chosen as the seller, type the area number in the box labeled "Type Seller," as shown in Figure A5. If the number is not a valid area, an error will pop up after "Solve" is clicked to inform the user the area is invalid.

Figure A5: Type the Area Number for the Seller



c. Bus - If "Bus" is chosen as the seller, type the bus number in the box labeled "Type Seller," as shown in Figure A6. If the number is not a valid bus, an error will pop up after "Solve" is clicked, informing the user the bus is invalid.

Figure A6: Type the Bus Number for the Seller

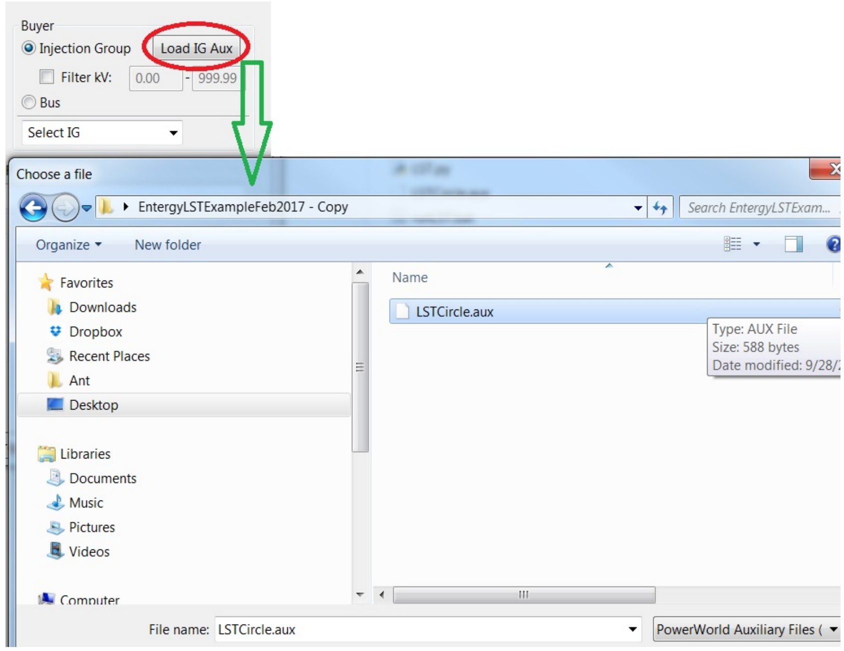


iii. Next, the user will select the "Buyer" type. The buyer would include the components listed in the circle. There are several different options for the buyer. The user could select "Injection Group" or "Bus."

a. Injection Group – In order to select an IG, there should be an auxiliary file that contains the buyer IG information. The user will again have to perform two steps when selecting the IG option.

    i. Step one would be to click the "Load IG Aux" button to load the appropriate auxiliary file, as shown in Figure A7, that will contain the IG.

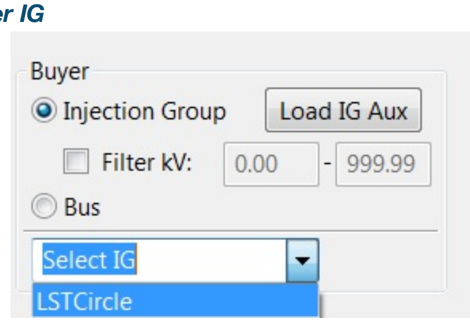
Figure A7: Select Buyer's Auxiliary File



ii. Once the file is chosen, step 2 requires the specific IG to be selected from the dropdown menu "Select IG," which will contain all injection groups found within the auxiliary file provided in step 1. This dropdown is shown in Figure A8.

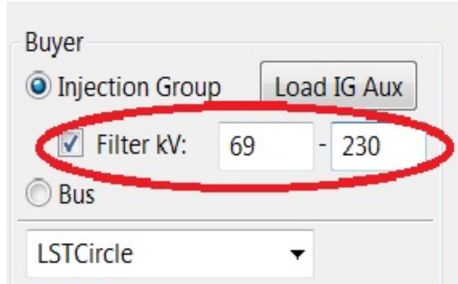
*Note: If an auxiliary file contains multiple IGs, all IGs will be listed in both buyer and seller dropdown menus after the file is processed. Any IGs already saved in the case will be available for selection from the dropdown menu.

Figure A8: Select Buyer IG



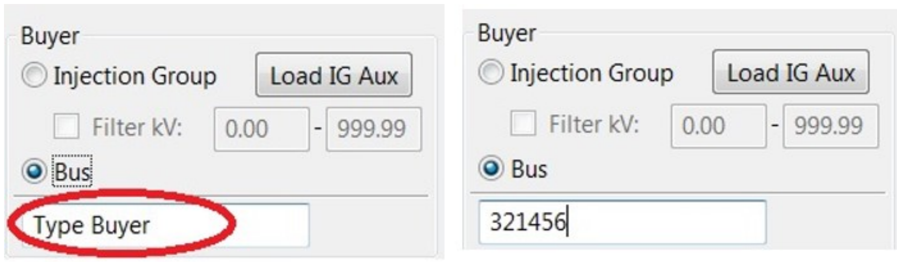
Once the IG is selected, there is a checkbox where the user can filter results based upon a kV range, as shown in Figure A9.

Figure A9: Filter the Buyer Injection Group by kV



b. Bus – If "Bus" is chosen as the buyer, type the bus number in the box labeled "Type Buyer," as shown in Figure A10. If the number is not a valid bus, an error will pop up after "Solve" is clicked, informing the user the bus is invalid.

Figure A10: Type the Bus Number for the Buyer

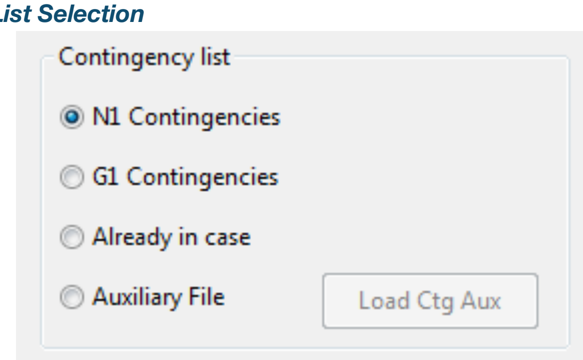


iv. Next, the user will move to the "List Areas to Change AGC Status to OPF" field. This allows the user to indicate which areas should have their AGC (automatic generation control) status changed to OPF (Optimal Power Flow), as shown in Figure A11. If the user leaves the area blank, it will default to the "Seller" area.

Figure A11: List Areas for Changing AGC Status to OPF

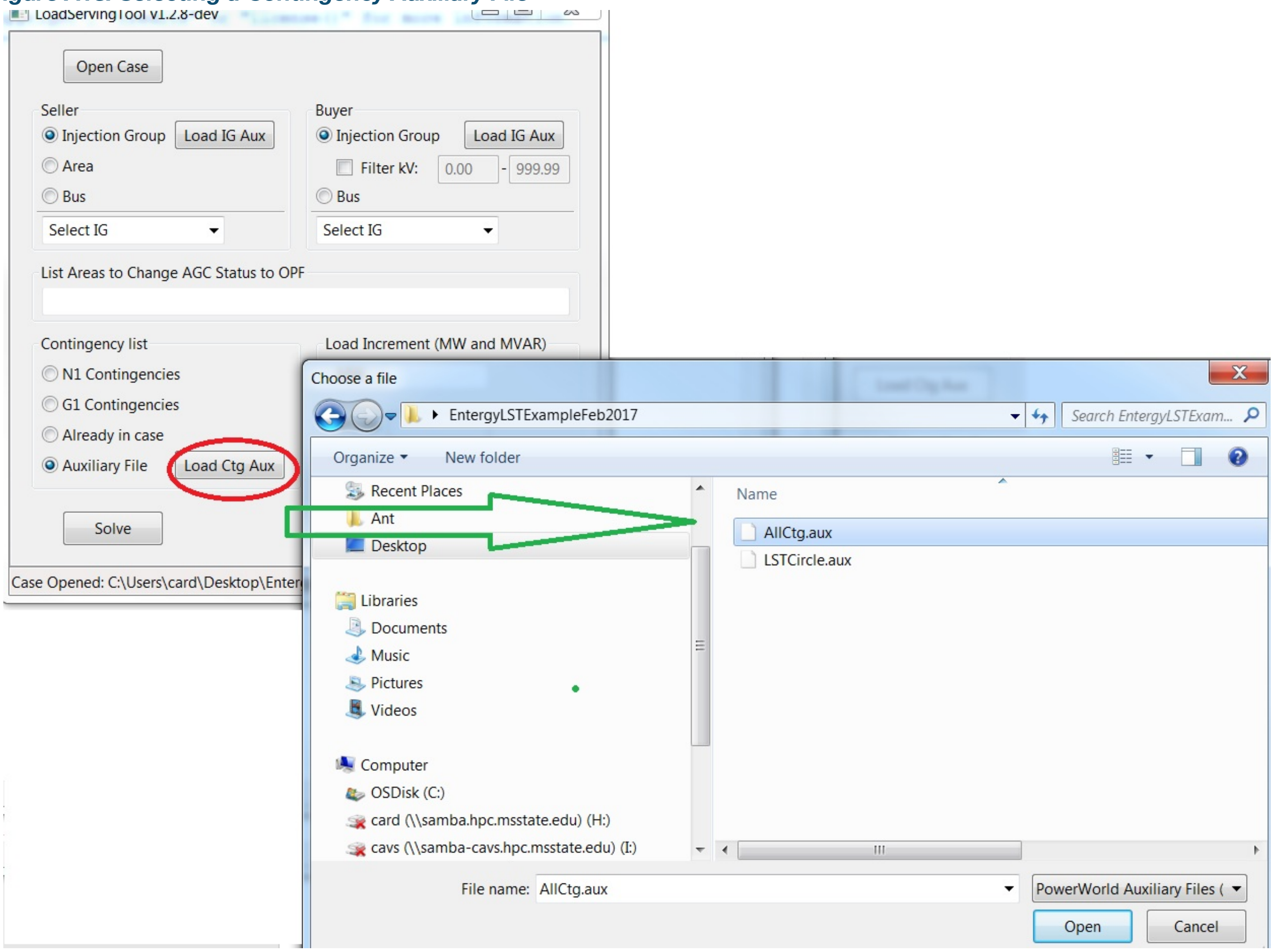
v. Next, the user will select the "Contingency List" to be used for ATC mode. Note that several options exist, as shown in Figure A12. It should also be noted that these contingencies are only used for ATC mode. The contingencies for SCOPF will be automatically generated by the program. SCOPF will use the worst five contingencies from previous ATC results, regardless of the selection here.

Figure A12: Contingency List Selection



a. N1 Contingencies – The program will automatically generate a contingency list that will include all N1 contingencies. Any other contingencies that existed in the PowerWorld file will be cleared automatically.
b. G1 Contingencies – The program will automatically generate a contingency list that will include all G1 contingencies. Any other contingencies that existed in the PowerWorld file will be cleared automatically.
c. Already in case – This option will use the contingencies already active in the PowerWorld case.
d. Auxiliary File – The user will select Auxiliary File and then click on "Load Ctg Aux" to browse to the contingency-file location, as shown in Figure A13. Any other contingencies that existed in the PowerWorld file will be cleared automatically.

Figure A13: Selecting a Contingency Auxiliary File



vi. Enter the MW and MVAR values for the load increment to be added into the "circle." MW is only required when an "Injection Group" is selected as the buyer type (see Figure A14). Specifying only the MW value ensures the P/Q ratio is maintained. Both MW and MVAR options are both available when "Bus" is selected (see Figure A15), but only MW is required.

Figure A14: Entering the Load Increment in MW If Buyer Selection Was Injection Group

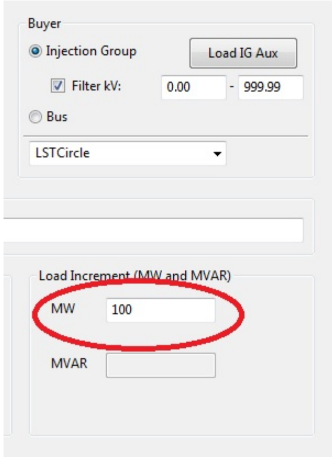
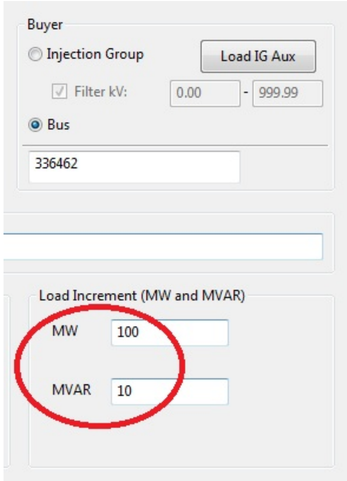


Figure A15: Entering the Load Increment in MW and MVAR If Buyer Selection Was Bus



vii. Click the "Solve" button. The status bar updates as the program runs (see Figure A16). When the solver completes, the status bar will display the additional load that was successfully served inside the circle (see Figure A17).

Figure A16: Selecting Solve to Run the Program

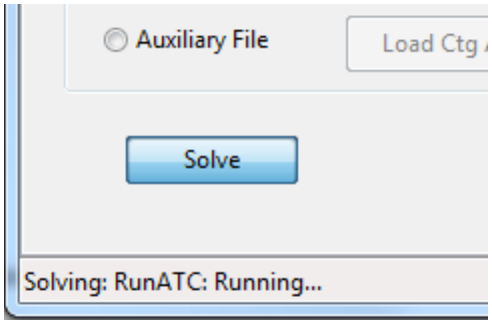
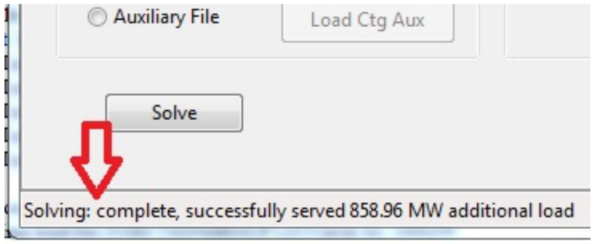


Figure A17: Status Bar Indicating Program Is Done and Additional Load Served in the Circle



viii. At this point, the user should click “Close” so that the appropriate output files can be written.

Step 3: Examine the Output

Two output files will be created once the user selects “Close” on the GUI. The first one is a results file that contains all of the input information selected by the user, the results of each ATC run, and the amount of additional load that was served. The file will be named with “_results.txt” appended to the PowerWorld case name. The results file will show the following information:

- **LST script version number.**
- **Name of the opened case.**
- **List of auxiliary files loaded into the case.**
- **Solver start time.**
- **Seller type and object (typically a name or number).**
- **Buyer type and object.**
- **Areas with AGC status changed to OPF.**
- **Load increment.**
- **Contingency selection.**
- **Number of contingencies based upon the contingency selection.**
- **All ATC top 5 results separated by loops (header information is provided for loads).**
- **A summary indicating the additional load that was successfully served**
- **Solver finish time.**
- **Solver elapsed time.**

The other file created will be the log file. The log file documents each step that the program executes and is used primarily for troubleshooting. The file will be named with “_log.txt” appended to the PowerWorld case name. This file will be created in the same directory as the PowerWorld case. Note that the program also saves an updated case using “_updated.pwb” appended to the PowerWorld case.

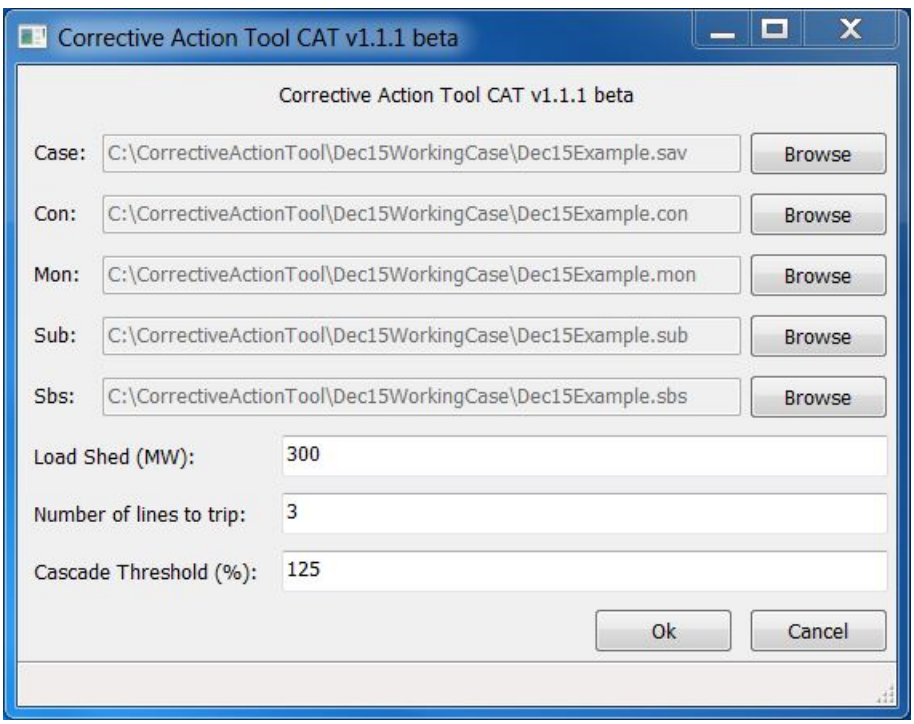
B. Corrective Action Tool

The purpose of this software project is to develop a Corrective Action Tool (CAT) to aid in performing NERC-required transmission-planning analyses utilizing the corrective action capabilities in PSS/E. This tool automates most of the time-consuming manual processes used to meet these requirements today.
The user must input a set of files for the CAT tool to use in conjunction with the Entergy-licensed PSS/E software. The tool will then determine, based on PSS/E simulations according to information within the files, if a project will exist or not for the defined scenarios within the files. The CAT implementation specifically involves automating the PSS/E corrective-action features of generation redispatch and load shedding. After a successful run, a "results file" is created that outputs a summary of the results as well as detailed information about generation redispatch, load shedding, non-consequential load loss due to overloading and islanding, and a tripped-line section.

Steps for Using the CAT Program:

Step 1: Run the Corrective Action Tool
The user will run the CAT_GUI python script. Upon running the script, the GUI shown in Figure A18 will appear.

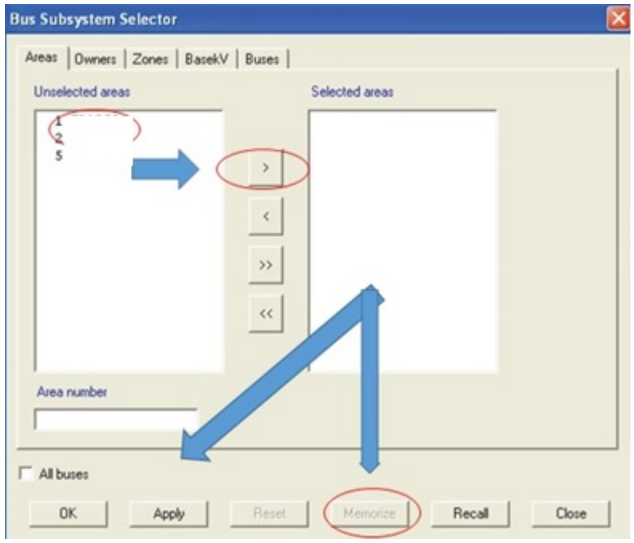
Figure A18: GUI for CAT



The user will browse and select several different files to be used within PSS/E automatically from the CAT program. Note that the sample files shown above all have the same file name with different extensions. The user may name the files in this manner, but it is not required. Most of the files would be familiar to the PSS/E user in the form of the case or "sav" file, the "con" file, the "mon" file, and the "sub" file. The only exception to that might be the "sbs" file, so the following paragraph instructs the user on the creation of such a file.

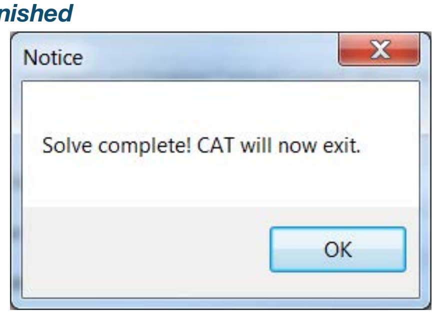
The information within an “sbs” or “sbsxml” file is needed by the CAT program. If such a file is not detected in the folder with the case file or the user does not select an sbs file, the program will use the information contained within the sub file if it contains only area(s) descriptions. If the user opts to use the information within the sub file, then the sbs input can be left blank in the GUI. If the user needs to create the sbs file, the user should open PSS/E and select “Bus” from the subsystem menu or click on the “Create a Bus Subsystem Selector.” This step will bring up the dialog box shown in Figure A19. When the appropriate selections are made, the user will select “Apply,” which most users are familiar with up to this point, and then “Memorize” to save the information in an sbs file. The “Memorize” step is an additional step to the normal PSS/E process.

Figure A19: Creation of “sbs” File in PSS/E



Once the file names are entered, the user next must input the amount of load shed in MW, the number of lines to trip, and the cascade threshold to provide decision point values for the CAT program. The user will then click the “OK” button for the program to begin execution. When the program has completed, the popup shown in Figure A20 will appear, and the user should click “OK” to view the results in an “output.csv” file and the “log.txt” file.

Figure A20: Popup Showing CAT Has Finished



Step 2: Examine the Output

Two output files will be created once the user selects “OK” on the GUI. The first one is an output file that contains a summary as well as detailed results for each contingency analyzed. The file will be named with “_output.csv” appended to the PSS/E case name. The file will contain the following specific information:

- **Summary Information**
  - Contingency Name.
  - Potential Project Needed – Yes or No.
  - Total Load Shed.
  - Total Gen Re-Dispatch.
  - NCLL.
  - LS+NCLL.
  - Number of Lines Tripped.
- **Individual Information**
  - Load Shed Amounts by Bus.
  - Gen Re-Dispatch Amounts by Bus.
  - NCLL Due to Trips by Bus (Overloads and Islanding).
  - Tripped Line Section Data (Overloads and Islanding).

The other file created will be the "_log.txt" file. The log file documents each step that the program executes and is used primarily for troubleshooting. The file will be named with "_log.txt" appended to the PSS/E case name. The file will be created in the same directory as the PSS/E case.

IX. Appendix B: Estimated Net Benefits of CAES Systems Constructed without Preexisting Infrastructure for Use Case 3

Figure B1: Net Benefits for Use Case 3 – CAES Constructed Without Preexisting Infrastructure

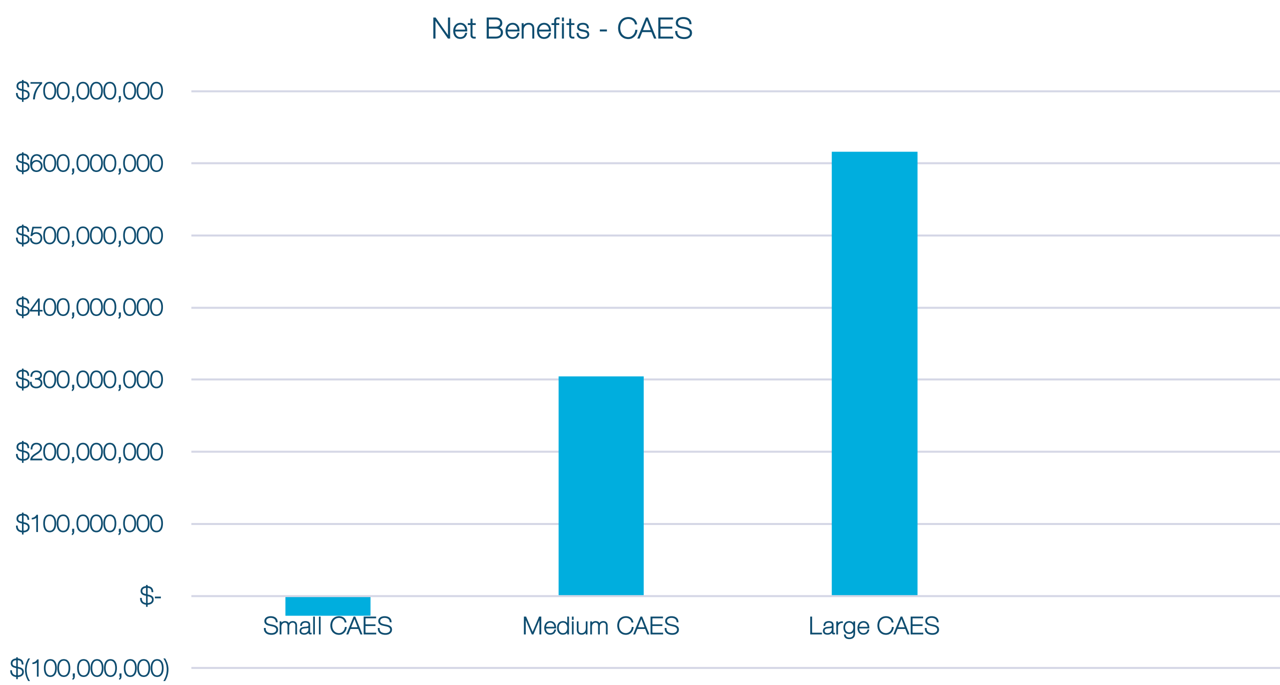


Figure B2: Net Stacked Benefits for Use Case 3 – Small CAES

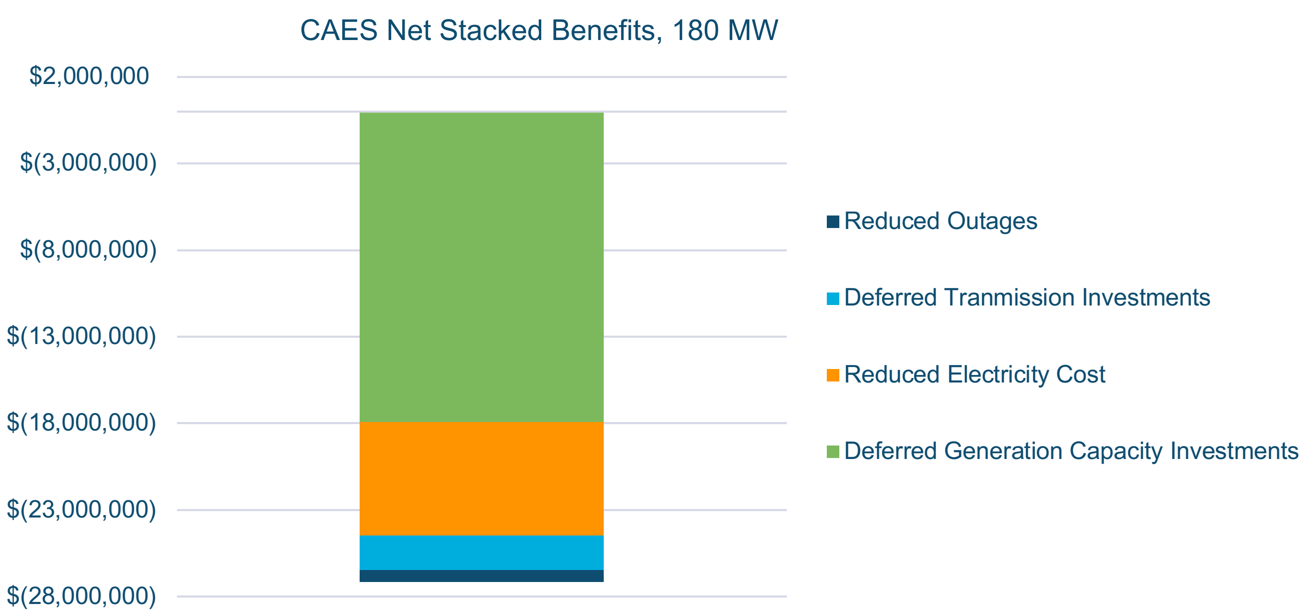


Table B1: Small CAES Stacked and Net Stacked Benefits Table – Use Case 3

Project Outcome	Value
Gross Benefits	
Total	**$647,617,300**
Deferred Generation Capacity Investments	$427,481,400
Reduced Electricity Cost	$156,743,700
Deferred Transmission Investments	$47,202,900
Reduced Outages	$15,998,200
Cost of Deployment, Total	**$674,768,100**
Net Benefits	
Total	**$(27,150,800)**
Deferred Generation Capacity Investments	$(17,921,791)
Reduced Electricity Cost	$(6,571,345)
Deferred Transmission Investments	$(1,978,941)
Reduced Outages	$(1,978,941)

Figure B3: Net Stacked Benefits for Use Case 3 – Medium CAES

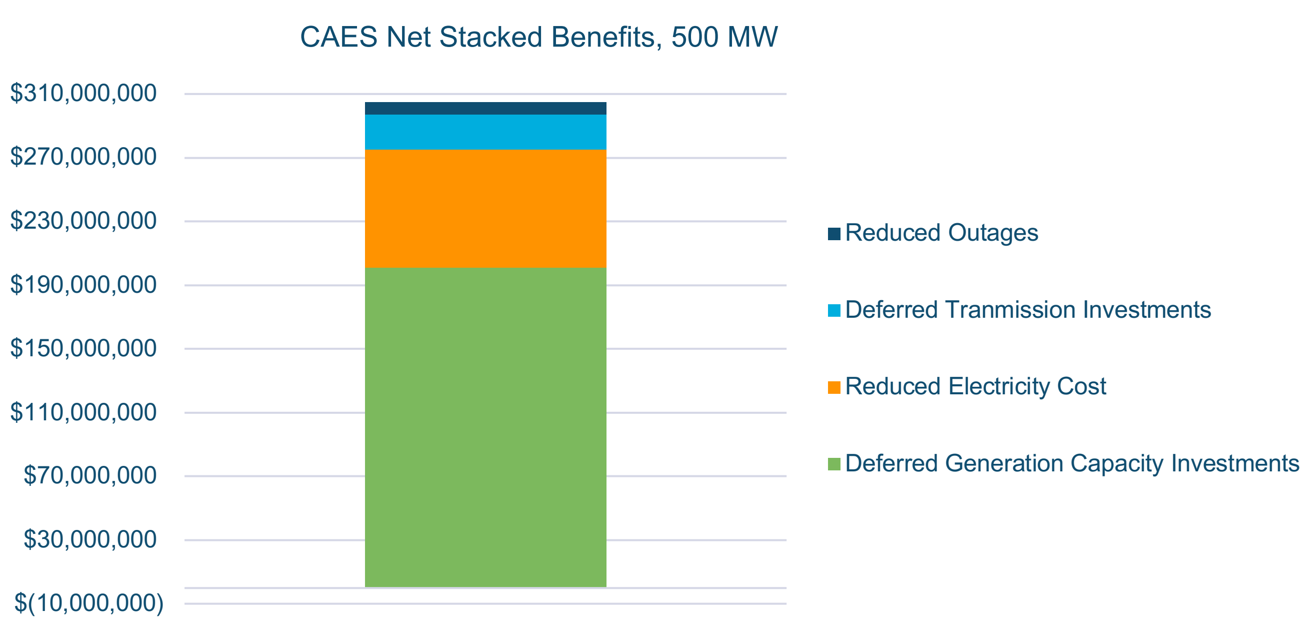


Table B2: Medium CAES Stacked and Net Stacked Benefits Table – Use Case 3

Project Outcome	Value
Gross Benefits	
Total	**$1,798,936,600**
Deferred Generation Capacity Investments	$1,187,448,800
Reduced Electricity Cost	$435,399,400
Deferred Transmission Investments	$131,118,200
Reduced Outages	$44,438,700
Cost of Deployment, Total	**$1,494,046,200**
Net Benefits	
Total	**$304,890,400**
Deferred Generation Capacity Investments	$ 201,253,196
Reduced Electricity Cost	$73,793,094
Deferred Transmission Investments	$22,222,395
Reduced Outages	$7,531,635

Figure B4: Net Stacked Benefits for Use Case 3 – Large CAES

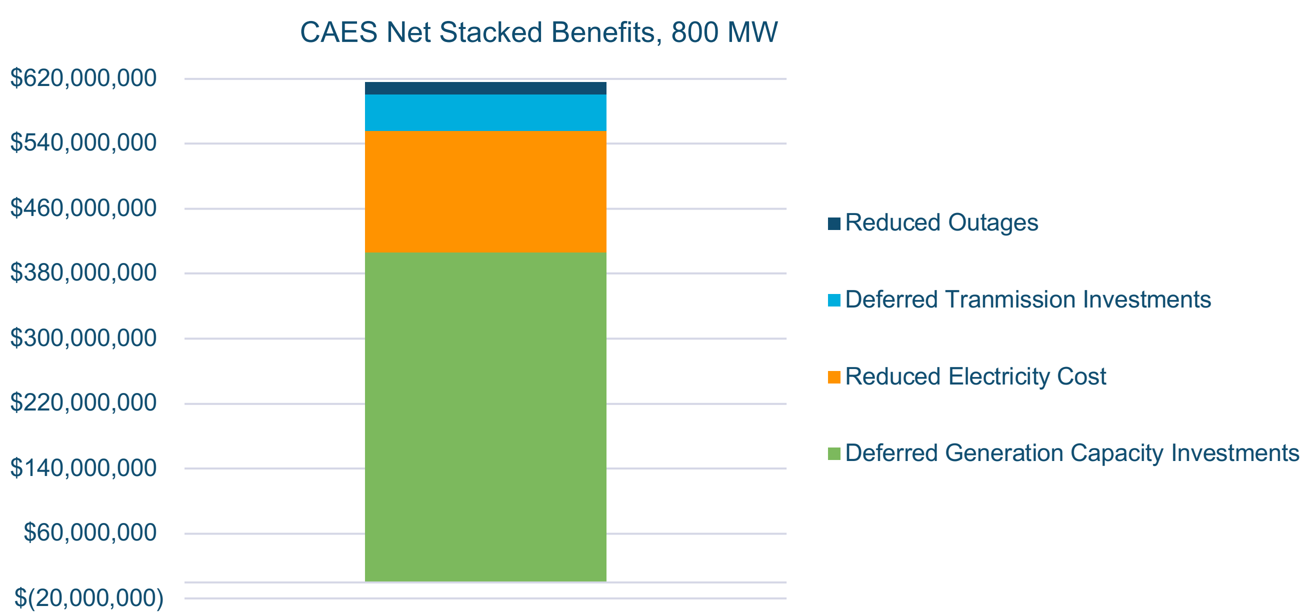


Table B3: Large CAES Stacked and Net Stacked Benefits Table – Use Case 3

Project Outcome	Value
Gross Benefits	
Total	**$2,878,299,200**
Deferred Generation Capacity Investments	$1,899,917,500
Reduced Electricity Cost	$696,639,200
Deferred Transmission Investments	$209,789,300
Reduced Outages	$71,102,600
Cost of Deployment, Total	**$2,262,119,400**
Net Benefits	
Total	**$616,179,800**
Deferred Generation Capacity Investments	$406,730,053
Reduced Electricity Cost	$149,134,948
Deferred Transmission Investments	$44,911,220
Reduced Outages	$15,221,484

X. Appendix C: Power Analysis for Use Case 5

This section lists the load data of the modified IEEE 118 Bus Test Case which includes updated MISO information used in this study. When January 1, 2017, load data of MISO local resource zones 8, 9, and 10 are chosen as an example, the average load level of the modified IEEE 118 Bus Test Case's load data is around 34% of average load level of MISO's load data. Therefore, in order to use the 118 Bus Test Case to simulate the studied power system, load data of MISO local resource zones 8, 9, and 10 are scaled down to around 34% of its historical data to fit the configuration of the IEEE 118 Bus Test Case.

Table 31: Modified IEEE 118 Bus Test Case Load Data and MISO Load Data

Hour	LRZ8_9_10 Actual Load (MWh)	ScaleDownLRZ8_9_10 Actual Load (MWh)
1	15,660	5,325
2	15,229	5,178
3	14,922	5,074
4	14,584	4,959
5	14,334	4,874
6	14,269	4,852
7	14,446	4,912
8	14,758	5,018
9	15,035	5,112
10	15,645	5,320
11	16,267	5,531
12	16,531	5,621
13	16,766	5,701
14	16,881	5,740
15	16,863	5,733
16	16,779	5,705
17	16,672	5,669
18	16,786	5,707
19	17,484	5,945
20	17,679	6,011
21	17,581	5,978
22	17,250	5,865
23	16,813	5,717
24	16,194	5,506

MISSISSIPPI STATE UNIVERSITY™
NATIONAL STRATEGIC PLANNING
& ANALYSIS RESEARCH CENTER

MISSISSIPPI STATE UNIVERSITY™
CENTER FOR ADVANCED
VEHICULAR SYSTEMS