FINAL REPORT

Design, Modeling, and Control of Hybrid Energy Storage System for Defense Installation Microgrids

ESTCP Project EW19-5277

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This project demonstrates the value of integrating optimized energy storage solutions, including multi-asset hybrid energy storage systems (HESS) within DoD microgrids. Proposed solutions improve energy security performance, including critical load coverage for 24 hour and 7 day outage scenarios, as a function of cost vs. similar microgrids without storage. The platform utilized also provides controls techniques to optimize and improve revenues, including those from energy market participation. Storage technologies evaluated included ultracapacitor, lithium ion, LiFePO4, zinc hybrid cathode, sodium sulfur, and flow battery technologies. An optimized microgrid and energy storage platform with integrated analytics and controls was utilized to evaluate potential HESS solutions. The approach combines economic optimization through the XENDEE platform and ASU's energy security model (ESM) to evaluate energy asset portfolios, critical load coverage probability, economic performance, and asset dispatch strategies. Project conclusions are that (1) three primary factors dominate economic performance: microgrid cost, available on-site PV generation, and local utility wholesale market participation and ancillary service revenues; and (2) optimizing the entire microgrid, with a focus on the optimizing sizing and integration of PV generation with energy storage can provide significantly improved economics.

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ACRONYMS AND ABBREVIATIONS

AFB	Air Force Base
ARB	Air Reserve Base
ASU	Arizona State University
CLCPC	Critical load coverage probability curve
DER	Distributed energy resource
DER-CAM	Distributed energy resource - Customer adoption model
DG	Distributed Generation
DoD	United States Department of Defense
ESM	Energy security model
ESS	Energy storage system
ESTCP	U.S. Department of Defense Environmental Security Technology Certification Program
HESS	Hybrid energy storage system
kW	Kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy or Electricity
MPC	Model predictive control
MTBF	Mean time between failure
MW	Megawatt
MWh	Megawatt-hour
NaS	Sodium sulfur
NAS	Naval air station
NPC	Net Protection Cost – expressed as net annual cost ($) of energy security per kW of peak critical load
O&M	Operations and Maintenance
PV	Photovoltaic
SERDP	Strategic Environmental Research and Development Program
SIR	Savings to Investment Ratio
UCAP	Ultra-capacitor
UPS	Uninterruptible Power Supply

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ABSTRACT

Design, Modeling, and Control of Hybrid Energy Storage Systems for DoD Microgrids

INTRODUCTION

This project optimizes energy storage implementation in Department of Defense (DoD) microgrids. Integrated modeling and design methods optimize a microgrid that can contain multiple energy storage asset types – a hybrid energy storage system (HESS) approach – in conjunction with diesel and renewable generation platforms.

OBJECTIVES

- Demonstrate the value of integrating optimized energy storage solutions, including multi-asset hybrid energy storage systems (HESS) within DoD microgrids;
- Improve energy security performance, including critical load coverage for 24 hour and 7 day outage scenarios as a function of cost vs. similar microgrid without storage at DoD facilities;
- Demonstrate controls techniques to improve revenue from energy market participation;

TECHNOLOGIES

Storage technologies evaluated broadly covered current commercially available storage approaches and chemistries, and included ultracapacitor, lithium ion, LiFePO4, zinc hybrid cathode, sodium sulfur, and flow battery technologies. This allowed modeling of storage integration considering a range of key technology attributes, such as C-rate, efficiency, and life.

An optimized microgrid and energy storage platform with integrated analytics and controls was utilized to evaluate potential HESS solutions. The approach combines economic optimization through the XENDEE platform and ASU's energy security model (ESM) to evaluate energy asset portfolios, critical load coverage probability, economic performance, and asset dispatch strategies, ensuring energy security metrics are achieved while providing the lowest cost energy.

PERFORMANCE AND COST ASSESSMENT

Primary conclusions of the study are that:

- For sites with little existing renewable generation, limited market participation options, and no ability to utilize incentives for renewables or storage investments, the integration of energy storage provides limited or no benefit economically;
- For sites where incentives can be considered, storage-enabled microgrids can:
  - improve energy security over 24-hour and 168-hour outages;
  - provide increased ability to meet in excess of 100% of critical load without resizing the system;
  - reduce fuel use during 7-day outages at most facilities by up to 22%;

  - integrate on-grid economic optimization with off-grid reliability to provide resilience with potential rapid return on investment at sites with significant market participation potential.

STUDY CONCLUSIONS

- Three primary factors dominate economic performance: microgrid cost, available on-site PV generation, and local utility wholesale market participation and ancillary service revenues.
- Optimizing the entire microgrid, with a focus on the optimizing sizing and integration of PV generation with energy storage can provide significantly improved economics.

EXECUTIVE SUMMARY

Design, Modeling, and Control of Hybrid ESS for DoD Microgrids

ES-1. INTRODUCTION

Southern Research, with 350Solutions, has managed a program to optimize energy storage implementation in Department of Defense (DoD) microgrids, with collaborators Arizona State University (ASU) and XENDEE Corporation developing a microgrid and energy storage design, modeling, and controls platform. The integrated methods from ASU and XENDEE optimize a microgrid that can contain multiple different energy storage types – a hybrid energy storage system (HESS) approach – in conjunction with diesel, renewable, and other generation platforms. Microgrid designs with optimized asset selection, sizing, and configuration are coupled with model predictive controls and dispatch algorithms to optimize real-time performance and economics.

ES-2. OBJECTIVES

The primary objectives of this project were to:

- Demonstrate the value of integrating optimized energy storage solutions, including the potential for multiple technology types and multi-asset hybrid energy storage systems (HESS) within DoD microgrids;
- Improve energy security performance as a function of cost compared to a similar microgrid without storage at DoD installations;
- Develop an integrated, microgrid design tool that rapidly produces performance- and cost-optimized, storage-technology-agnostic, customized microgrid designs and specifications;
- Demonstrate controls techniques to improve revenue from energy market participation;
- Perform co-simulation of design and controls methodologies to maximize performance and financial objectives for the project lifetime.

ES-3. ENERGY STORAGE TECHNOLOGIES

The project team selected six energy storage technologies as summarized in Table ES-1. Storage technologies evaluated broadly covered current commercially available storage approaches and chemistries. This allowed modeling of storage integration considering a range of key technology attributes, such as C-rate, efficiency, and life. Each of these core technology types was selected based on ability to excel in one or more of the six key performance attributes: coverage, availability, reliability, duration, ride-through capability, and stacked-value.

Table ES-1. Summary of Modeled ESS

Manufacture	Technology/ Chemistry	Expected Life (Cycles)	C-rate	Round Trip Efficiency (%)	Storage Cost ($/kWh)
Maxwell	Ultra-capacitor	1,000,000	Balance of system limited	85-95	
All Cell	Li-ion	2,200	3C/2	90	350
Blue Planet	$LiFePO_4$	8,000	1C	98	650
Eos	Aqueous zinc	5,000+	C/4	75	240
NGK	Sodium sulfur	4,500+	C/6	75	317
Avalon (lower cost for >20MWh)	Flow	20,000+	C/4	80	563/398

ES-4. DOD INSTALLATIONS MODELED

Five DoD installations with varying microgrid capacities were evaluated for design and incorporation of an optimized the HESS approach as summarized in Table ES-2.

Table ES-2. Installation Characteristics and Potential Microgrid Benefits

Installation	Selection Rationale & Characteristics of Interest
Westover ARB	Smallest facility with lowest annual electricity cost. High cost structure. High projected comparative solar capacity. Potential for microgrid to cover significant peak and critical load.
Naval Base Ventura County	Mid-sized facility. California market (high electricity cost). Low PV capacity (but significant potential). Low critical load as percentage of peak demand. Small ESS investment with potential resiliency impacts.
Holloman AFB	Significant PV resource as percentage of peak (33%) and critical (83%) loads. Large utility with demand and time of use charges. High potential for utilizing solar PV plus energy storage.
NAS Patuxent River	Large energy consumer. Regionally unique (mid-Atlantic). Electric Cooperative supplier. Unique use case. TBD based on utility pricing structure. PJM market access.
Fort Bliss (Army)	Largest energy consumer of group. Small critical load as percentage of peak demand, but largest critical load of all sites. Large, vertically integrated utility with multiple price structures. Potential for significant quantity of energy storage to mitigate time of use and demand charges.

ES-5. MODELING METHODOLOGY

An optimized microgrid and energy storage platform with integrated analytics and controls was utilized to evaluate potential HESS solutions at each of the five select DoD installations. This approach rapidly provides tailored energy storage enabled microgrid designs for any installation by considering climate zone, local energy market, and location specific use cases. The approach combines economic optimization through the XENDEE platform and ASU's energy security model (ESM) to evaluate energy asset portfolios. This method ensures energy security metrics are achieved while providing the lowest cost energy. Figure ES-1 shows the general process used to select the optimal energy asset portfolio for each of the considered bases.

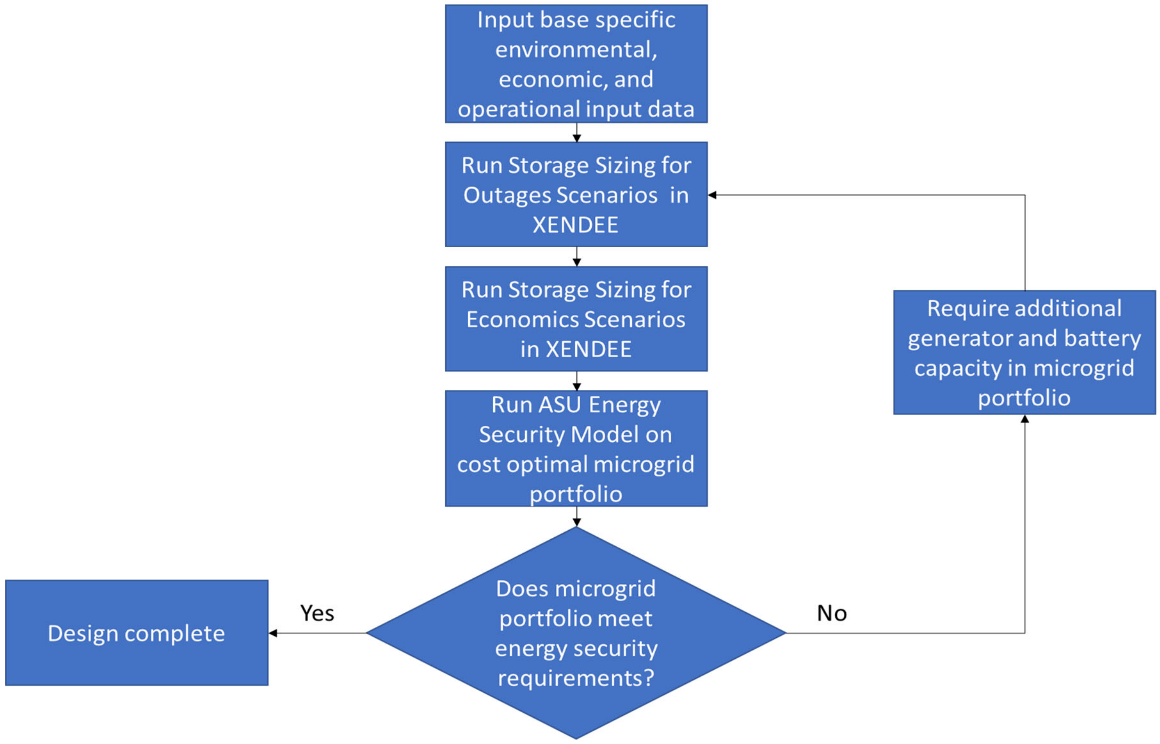

Figure ES-1. Process Flow Diagram Detailing the Steps Used to Calculate the Cost-Optimal Microgrid Portfolio for Energy Security Operations of Each Base Considered.

The models utilized included the use of the following tools:

- XENDEE: XENDEE secure cloud computing microgrid platform (XENDEE, 2017) provides economic system optimization via DER-CAM technology – a state-of-the-art decision support tool for decentralized energy systems, including buildings and microgrids – and also implements critical electrical design analysis (i.e. power flow, short circuit, reliability, arc-flash).
- ASU Energy Security Model (ESM): ASU's Energy Security Model (ESM) is a Python-based standalone model that, for our purposes, calculates a critical load coverage probability curve (CLCPC) and provides an optimized dispatch methodology to maximize coverage probability. The model can be used for real-time microgrid controls.

ES-6. PERFORMANCE ASSESSMENT

A summary of the primary performance metrics and the performance of the optimized ESS-enabled microgrid design is provided in Table ES-3. Key findings are:

Energy Storage Technology Selection:

- For the core case with only potential energy storage addition and no market participation or incentives, energy storage is not specified in the optimal microgrid for three locations. For Ft. Bliss and NAS Patuxent, small quantities of energy storage are specified.

- When incentives and wholesale market participation are included, energy storage is selected for all sites, with significant impacts on net protection cost and levelized cost of electricity;
- The overall difference in performance and economic impacts between different storage options in the optimized microgrid is quite small, and depends highly on the system costs. For these cases, any of four identified technologies could be selected with <1% impact on economics, including net protection cost and levelized cost of electricity;
- A LiFePO4 battery was identified as the optimal storage technology to use in four military base's optimal portfolio due to its high lifetime and low self-discharge rate. A flow battery was identified as the optimal storage technology for Westover for the same reasons. However, other technologies also show promise with nearly equivalent economic performance.
- The combination of an ultracapacitor with battery storage typically provides the best performance, with potential for significant reductions in UPS and generator costs.

Energy Security Performance:

- Performance objectives related to critical load coverage (24- and 168-hour) were met by the economically optimized microgrid design and dispatch scenario at Holloman (no ES), Ventura (no ES), and Fort Bliss (with ES), but not at Westover and Patuxent (24 hr);
- When access to incentives results in energy storage specification at all sites, the critical load coverage performance objectives are readily met. The optimized ESS enabled microgrid designs provide significant improvements in reliability to meet critical loads, especially for long outage duration (168-hour), and greater than 50% probability to meet 130% of critical load for 24 hour outages.
- Significant capability is provided to support portions of critical loads when no fuel was available are demonstrated for the optimized ESS microgrid when incentives are enabled.
- Fuel use was reduced for all sites with the optimized ESS microgrid (with incentives) compared to the baseline microgrid, when covering 100% critical load.

Table ES-3. Summary of Performance for Optimized Storage-enabled Microgrid.

Performance Objective	Reliability to Meet 100% of Critical Load	Reliability to Meet 130% of Critical Load	Reliability to Meet 10% and 30% of Critical Load w/ no Fuel	Net Life-cycle Costs of Deployment and Operation	Fuel Use Reduction to Meet 100% Critical Load
Success Criteria	**Meets or exceeds reliability probability curve for baseline microgrid for 24-hour, 168-hour outages.**	**Probability to serve critical load 24-hour and 168-hour outages.**	**Probability to serve critical and ride-through load. No minimum standard.**	**Net cost is at or below level of baseline microgrid in current and future volatile scenarios.**	**Fuel use is at or below the level of the baseline microgrid.**
Objective Met?	Yes, for all installations, when Inc are considered	No Min. Standard. Results Below	No Min. Standard. Results Below	Met for Westover, Holloman, Ft. Bliss.	Yes, for all installations, w/ optimized ES-microgrid
Metric	**Probability to meet load (%) for 24 hr/168 hr outage**	**Probability to meet load (%) for 24 hr/168 hr outage**	**Probability to meet load (%) for 24 hr and 10%/30% of critical load**	**Net cost of protecting each kilowatt of peak critical load ($/kW)**	**Average fuel saved compared to the baseline microgrid (gal/outage)**
Westover ARB Requirement	99.84/95.08	NA/NA	0/0	165.94 (baseline microgrid)	NA
Westover ARB Results - No Inc	96.87/81.77	56.48/18.53	0/0	129.77	0
Westover ARB Results - With Inc	100.00/100.00	94.74/85.89	100.00/59.45	18.67	-25
Westover ARB Results - Sized Solar	100.00/100.00	99.93/89.21	89.04/43.53	Not calculated	672
Holloman AFB Requirement	99.04/78.58	NA/NA	0/0	98.35 (baseline microgrid)	NA
Holloman ARB Results - No Inc	99.28/86.47	73.51/38.40	0/0	64.12	0
Holloman AFB Results - With Inc	99.96/96.93	99.5/61.07	97.53/0.00	59.40	16,500
NAS Patuxent Requirement	98.30/67.37	NA/NA	0/0	97.63 (baseline microgrid)	NA
NAS Patuxent River Results - No Inc	98.12/80.88	49.62/5.65	0.16/0.00	66.37	5,949
NAS Patuxent River Results - With Inc	98.12/80.88	49.62/5.65	0.16/0.00	64.12	5,949
NAS Patuxent Results - Sized Solar	98.90/86.26	33.42/1.89	7.19/0.00	Not calculated	20,155
NB Ventura Co. Requirement	99.43/85.81	NA/NA	0/0	135.45 (baseline microgrid)	NA
NB Ventura Co. Results - No Inc	97.03/67.88	32.59/0.00	0/0	76.89	0
NB Ventura Co. Results - With Inc	99.63/89.10	66.80/3.64	96.39/0.00	75.38	2,937
NB Ventura Co. Results - Sized Solar	99.91/98.82	42.98/4.34	99.99/0.00	Not Calculated	17,899
Fort Bliss Requirement	99.25/82.25	NA/NA	0/0	82.70 (baseline microgrid)	NA
Fort Bliss Results - No Inc	99.48/90.76	72.50/51.20	0.00/0.00	31.17	20,807
Fort Bliss Results - With Inc	99.97/98.10	79.03/63.77	0.15/0.00	31.49	20,716

Optimal storage capacity for each technology type and installation, as well as projected levelized cost of energy (LCOE)[1] for each system design are provided in Figure ES-2a and ES2b (design with incentives).

ES-7. COST ASSESSMENT

Estimated energy storage system costs are summarized in Table ES-4.

Table ES-4. Optimized Storage-enabled Microgrid Systems for All Locations

	Holloman AFB	Westover ARB	NB Ventura Co.	Fort Bliss	NAS Patuxent River
Best Choice Scenario	Blue Planet-Cap;	Avalon-Cap;	Blue Planet-Cap;	Blue Planet-Cap;	Blue Planet-Cap;
Microgrid Total Cost [k$]	**6509**	**5763**	**5876**	**12504**	**8545**
Energy Storage [k$]	503	2391	881	755	252
ES-Balance of System [k$]	266	1263	465	398	133
Microgrid infrastructure [k$]	262	174	262	262	349
UPS [k$]	2103	809	1456	3888	2750
Diesel Generators [k$]	3375	1125	2813	7200	5063
Original Diesel Gen	9	4	7	8	12
HESS Diesel Gen	6	2	5	6	9

Note: All best choice scenarios were found modeling ITC/MACRS incentives applied to storage, and include market participation, where available. Cost-optimal solutions for bases when designed without applying incentives selected no storage for four of the bases.

Overall, for the optimized ES-enabled microgrid (with ITC MACRS incentives), net lifecycle costs were below those of the baseline microgrid for three sites. Important findings are:

- On each base, the greatest ancillary service (AS) potential is provided by installing the largest optimal ESS possible, providing the most capacity for participation.
- Westover ARB provided the greatest potential for AS revenue and significant differences in LCOE for different technologies due to large solar PV generation combined with ES.
- LCOE is directly correlated with AS revenue, where larger shares of AS revenue produce the solutions with the lowest overall LCOE.
- For the Wholesale Market cases, low RTP rates drive down storage sizing and AS revenue.

Example revenues for the optimized ES-enabled microgrid for Westover ARB are summarized in Figure ES-3.

PV system size relative to total load is a primary driver in storage sizing and operation. For Naval Base Ventura, if all three technologies – energy storage, PV generation, and generators – are optimally sized, rather than restricting the PV array capacity to the pre-planned 830 kW, the optimal technology portfolio includes a much greater amount of PV and storage.

[1]Levelized Cost of Energy (LCOE) – measures lifetime costs divided by energy production for a specific site or project via calculation of net present value of the total cost of building and operating a power plant (microgrid) over an assumed lifetime.

The increase in PV and storage capacity improves microgrid ability to meet critical loads through renewable generation and storage, and fewer diesel generators are needed for backup power. A significant reduction in both LCOE (~17%) and total annual energy cost (~15%) can be achieved with additional PV and storage, with more potential opportunities for demand charge reduction and price arbitrage during normal operation. Both utility energy purchases and demand charges are significantly reduced when the microgrid is sized without the 830 kW array capacity restriction.

Figure ES-2a. Optimal Microgrid Portfolio and Levelized Cost of Electricity of Each Base Modeled for Each Battery Technology Paired with a Ultracapacitor/UPS System that Can Extend the Expected Life with No ITC or MACRS Incentives

Figure ES-2b. Optimal Microgrid Portfolio and Levelized Cost of Electricity of Each Base Modeled for Each Battery Technology Paired with a Ultracapacitor/UPS System that Can Extend the Expected Life Including ITC and MACRS Incentives.

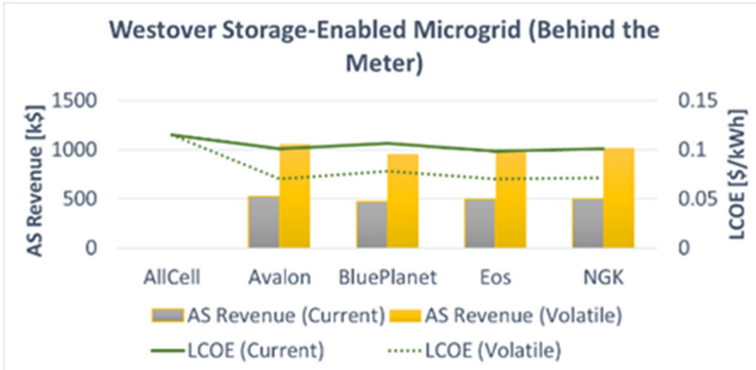

Figure ES-3. Potential Revenues from Ancillary Services at Westover ARB with Storage-enabled Microgrid.

Each battery technology is paired with a ultracapacitor/UPS system that can extend the expected life including ITC and MACRS incentives.

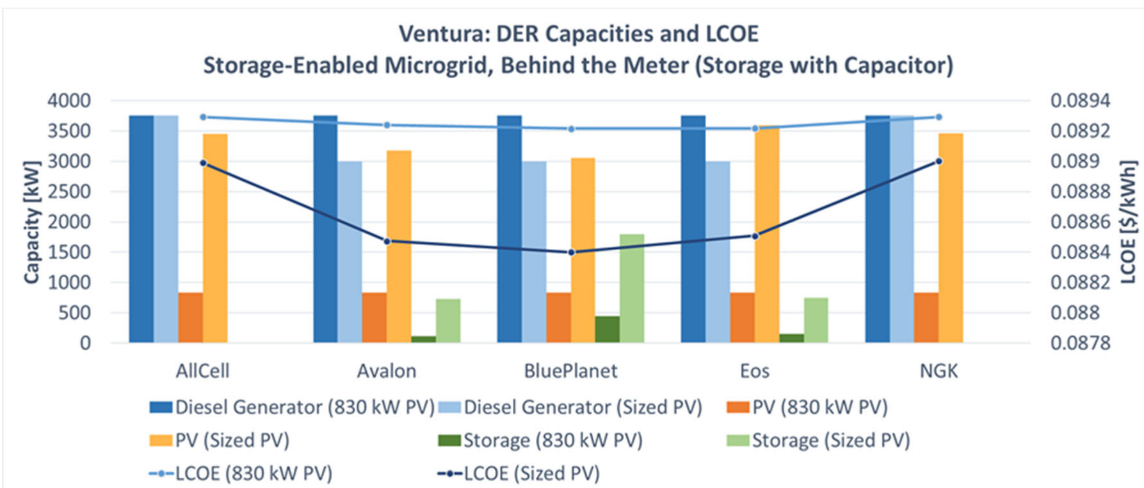

Figure ES-4. Optimal sizing of all assets (PV, generators, storage) for Ventura. Each battery technology is paired with a ultracapacitor/UPS system that can extend the expected life including ITC and MACRS incentives.

ES-8. STUDY CONCLUSIONS

Primary conclusions of the study are that an optimized storage-enabled microgrid can:

- improve energy security over 24-hour and 168-hour time horizons as measured by the critical load coverage probability (CLCP);
- provide increased ability to meet greater than 130% critical load without resizing the system;
- reduce fuel use by up to 22% during 7-day outages, thereby increasing mission autonomy in case of fuel supply shortage.

- integrate on-grid economic optimization with off-grid reliability to provide resilience with potential return on investment at sites with significant market participation potential.
- lower net protection cost via optimization of assets, including diesel generators, by adding storage and reducing generator units as compared to the baseline generator-only case, while meeting required critical load coverages.

In addition, important factors to consider include:

- Implementation of a hybrid system with ultracapacitors can improve the lifetime of long-duration storage, with additional potential benefits to be evaluated in Phase II.
- Hybrid battery-battery energy storage systems have potential to provide benefits in certain applications, but the economics of such systems are not typically better than single technology systems for the cases evaluated.
- Optimizing the entire microgrid, with a focus on the sizing and integration of PV generation with ESS can provide significantly improved economics, e.g. reducing LCOE by an added 15% and increasing no-fuel critical load coverage by 70+% for NB Ventura County.
- Microgrids that participate in wholesale markets could increase revenue at three of the five modeled installations, with potential for nearly $0.5M/year in additional revenue for a facility such as Westover ARB.

1.0 INTRODUCTION

Southern Research has managed a program to optimize energy storage implementation in Department of Defense (DoD) microgrids, with collaborators Arizona State University (ASU) and XENDEE Corporation developing a microgrid and energy storage (ES) design, modeling, and controls platform. The integrated methods from ASU and XENDEE optimize a microgrid that can contain multiple different energy storage asset types – a hybrid energy storage system (HESS) approach – in conjunction with diesel, renewable, and other generation platforms. Microgrid designs with optimized asset selection, sizing, and configuration are coupled with model predictive controls to optimize real-time performance and economics.

The ASU-XENDEE HESS microgrid modeling approach was applied to evaluate a set of five DoD installation microgrids to evaluate performance for different technology packages and conditions at each location, rapidly identifying an optimal system design, including energy storage technology specification and control-dispatch strategy for each location. This model development and system design effort represents Phase I of the Design, Modeling, and Control of Hybrid ESS for DoD Microgrids project (ESTCP Project Number EW19-5277).

1.1 BACKGROUND

DoD is the largest single consumer of energy in the United States. In FY 2015, DoD's fixed installations, which contain 284,000 buildings and 2 billion square feet of space, consumed 1 percent of the total electric energy consumed in the United States, at a cost of almost $4 billion [1]. Domestic military installations are highly dependent on a commercial grid that is vulnerable to disruption due to aging infrastructure, severe weather, and physical- and cyber-attacks. Additionally, major domestic power outages are increasing in frequency and severity, impacting the resiliency and functionality of military bases.

The military has long relied on standalone generators with short-term fuel stockpiles to provide emergency backup power for buildings with "critical loads"—functions related to housing, life safety and health, public safety, communications, environmental systems, and critical mission support [2]. A large installation might have hundreds of standalone generators, many hard-wired to a single building. Additionally, many individual base tenant-operators purchase and maintain their own generators with little or no coordination with one another or with the base's central staff. Standalone generators have endured as the military's strategy for energy security because of the high degree of operator control they afford and because they are affordable. To support ride-through capability for critical loads, generators are used in conjunction with uninterruptible power supplies (UPS), typically consisting of lead acid batteries, sized to manage short (second to minute time scale) power requirements.

Limitations of this backup strategy include inefficient generator sizing, reliability, high maintenance needs and associated high failure rates, inability to prioritize selective load coverage, and operational costs. In addition, the UPS systems require regular maintenance and battery replacement. Finally, none of these systems can, in current system designs, be utilized to participate in local energy markets, provide ancillary services, or support energy management approaches to improve system economics. The one caveat known to the team is the microgrid at Marine Corps Air Station Yuma, which is a diesel-only microgrid, connected to the utility grid in-front-of-the-meter, operated by the local utility, and can be controlled through frequency regulation with respect to technical and economic signals from the utility grid. Lessons from that project, and other DoD installation energy and civilian infrastructure modernization efforts, provide insights for this work.

With growing concerns of whether military bases can maintain critical functions during outages that last for days or weeks as opposed to hours, DoD is actively pursuing the deployment of microgrid technologies to provide improved energy security for longer durations. Within these microgrids, a local system of distributed energy resources (DERs – including renewables) and electrical loads can operate as a single entity either in parallel to the commercial grid or independently in island mode. Microgrids can provide major advantages over standalone generators for providing energy security and address many of the limitations characteristic of current standalone generating practices. However, many microgrids in use today within and outside of DoD are relatively unsophisticated, with limited ability to integrate intermittent renewable DERs, little or no storage capability, and no ability to gain revenue through participation in energy markets or exploit savings through energy management while grid-tied. By contrast, advanced or "smart" microgrids can operate seamlessly both in parallel to the grid and in island mode and integrate intermittent renewable DERs. Advanced energy storage enabled microgrids also offer the potential for improved system economics by enabling energy management, peak shaving, electricity market participation, reduced generator count and operating hours, and stored renewables to value-stack from multiple asset types.

In addition to resiliency and vulnerability concerns, DoD has worked with the private sector to develop renewable generation assets on military installations. A major goal of each of the Defense Services – Army, Air Force, Navy – has been to reduce their utility costs and meet their respective goals to produce or procure 1 gigawatt (GW) of renewable energy. Most of their sources of renewable energy (commonly solar and wind) are intermittent. Although of value to improving energy security in some circumstances, they cannot be relied on as a backbone of an energy security solution in the absence of energy storage. Given DoD's energy security requirements, its plans to deploy microgrids, and its existing and planned deployment of renewables, the potential to use energy storage to provide a better and more cost-effective energy security solution is significant.

Furthering the utility and benefits of smart microgrid implementation at DoD installations with energy storage capacity, this project developed a comprehensive approach to identifying and dispatching optimized energy storage solutions composed of one or more energy storage technologies, applicable to a wide variety of microgrid implementation scenarios. This ES-technology-agnostic microgrid modeling approach may potentially achieve a higher level of performance at a lower cost compared to implementation of a single storage technology in certain applications. By taking advantage of the fundamentally different attributes of various storage technologies and operating them at optimal conditions, we can address both power-intensive and energy-intensive use cases, and power quality management, without oversizing a single technology that is attempting to cover all scenarios, and improving component life. The approach combines technology for microgrid analytics and design by XENDEE with advanced model predictive control techniques by Arizona State University, and a range of storage technologies from commercial vendors. Using this approach allows the optimization of large-scale HESS solutions to maximize six key microgrid attributes critical to DoD energy needs: coverage, availability, reliability, duration, ride-through capability, and stacked-value.

1.2 OBJECTIVE OF THE DEMONSTRATION

The primary objectives of this Phase I project were to:

- Demonstrate the value of integrating optimized energy storage solutions, not constrained to a single energy storage technology type or vendor, while including the potential for multi-asset hybrid energy storage systems (HESS) within DoD microgrids;
- Improve energy security performance as a function of cost compared to a similar microgrid without storage at DoD installations;
- Develop an integrated, microgrid design tool that rapidly produces performance- and cost-optimized, storage-technology-agnostic, customized microgrid designs and specifications for site specific installations;
- Demonstrate controls techniques to improve revenue from energy market participation;
- Perform co-simulation of design and controls methodologies to maximize performance and financial objectives for the project lifetime.

Specific primary technical performance objectives were also specified by ESTCP, including:

- Covering 100% and 130% of critical base loads for outages ranging from 1 hour to 7 days;
- Covering 10% and 30% of critical base loads for outages ranging from 1 hour to 24 hours with no remaining fuel available for diesel gensets;
- Providing lifecycle and annualized costs for 20-year lifetime starting in 2020 for each proposed solution under current and future volatile market scenarios that improve upon the baseline microgrid.

The project team selected six ESS technologies as summarized in Table 1 and described in Section 2. Each were evaluated in site-specific optimized microgrid designs. Storage technologies that broadly covered the commercially available storage approaches and chemistries were pursued and selected based on commercial availability and vendor interest in project participation to represent potential ESS approaches. The range of core storage technologies selected allowed the project to model storage integration considering key technology attributes, such as C-rate, efficiency, and life.

Table 1. Summary of Modeled ESS

Manufacture	Example Model	Technology/Chemistry
Maxwell	Grid Energy Storage System BMOD0071	Ultra-capacitor
All Cell	Core kWh+	Li-ion
Blue Planet	Blue Ion	$LiFePO_4$
Eos	Eos Aurora 2.0 – Zynth Battery	Aqueous zinc
NGK	NAS Energy Storage System	Sodium sulfur
Avalon	*Avalon*™ Flow Battery	Flow

Each of these core technology types were selected based on their ability to excel in one or more of the six key performance attributes: coverage, availability, reliability, duration, ride-through capability, and stacked-value. In addition, these technologies were selected to represent a wide range of energy storage types, performance characteristics, and economics. Specific technology vendors were able to provide the necessary detail to enable accurate modeling. However, the modeling, design, and dispatch approach demonstrated here is ES-technology agnostic, and can be used to consistently evaluate a wide variety of potential candidate technologies beyond those evaluated here.

To evaluate the potential technical and financial benefits from integration of these technologies in existing DoD microgrids, the project utilized advanced decision and modeling tools to compare performance models to those of current DoD practices or baseline microgrids without energy storage.

Five DoD installations with varying microgrid capacities were identified by ESTCP for modeling the HESS approach and included:

- Westover Air Reserve Base (ARB) – An Air Force Reserve Command installation located in Chicopee, MA;
- Naval Base (NB) Ventura County – Consolidated Point Naval Base Ventura County (NBVC) is a naval installation composed of three operating facilities in southern California - Point Mugu, Port Hueneme and San Nicolas Island;
- Holloman Air Force Base (AFB) – Otero County, NM;
- Naval Air Station (NAS) Patuxent River – A Naval Air Station located in St. Mary's County, MD; and,
- Fort Bliss Army Base – A US Army post located in New Mexico and Texas with headquarters in El Paso, TX.

1.3 REGULATORY AND MARKET DRIVERS

The primary market drivers and methods to improve system economics considered in our modeling approach, often driven by regulatory and policy actions described below, include:

- Wholesale market participation – selling electricity to the grid;
- Ancillary grid services - such as frequency regulation, reactive power and voltage control, and reserves (contingency, flexibility, following);
- Behind-the-Meter (BtM) energy management (demand response charge mitigation (via peak shaving), real time pricing management).

Access to specific markets or approaches are unique to each utility and region, and, therefore, unique to each DoD installation. Specific electricity market, ancillary service market, and BTM management activities applicable to each installation were reviewed and incorporated in modeling efforts for each location is summarized in
Table 2.

Table 2. Electricity Market Options Evaluated for Each Installation

Site	Behind the Meter Market Options	Wholesale Market Options	Wholesale Market Options Modeled
Holloman AFB	Energy price arbitrage, Demand charge reduction, peak shaving	None	None
Fort Bliss	Energy price arbitrage, Demand charge reduction, peak shaving	None	None
Westover ARB	Energy price arbitrage, Demand charge reduction, peak shaving, spinning and non-spinning reserve AS participation	Real-time energy pricing, spinning and non-spinning reserve AS participation, Regulation capacity AS participation	Real-time energy pricing, spinning and non-spinning reserve AS participation
NAS Patuxent River	Demand charge reduction, peak shaving, synchronized reserve AS participation	Real-time energy pricing, synchronized reserve AS participation, Regulation (capacity and performance combined) AS participation	Real-time energy pricing, synchronized reserve AS participation
NB Ventura Co.	Energy price arbitrage, Demand charge reduction, peak shaving, spinning reserve AS participation	Real-time energy pricing, spinning reserve AS participation, Regulation down AS participation, Regulation up AS participation	Real-time energy pricing, spinning reserve AS participation

The regulatory activities that are enabling market participation and implementation of energy storage are discussed further below.

Federal and state governments are moving to encourage energy storage. Storage has benefited at the federal level from targeted loan and incentive programs offered by the U.S. Department of Energy and from efforts by the Federal Energy Regulatory Commission (FERC) to clear a path to wholesale market participation [3]. These drivers are relevant to DoD installations and participating energy markets.

FERC has issued four orders in recent years that help energy storage. It also issued a notice of proposed rulemaking, or NOPR, in November 2016 proposing transparent market rules for energy storage facilities to participate in organized markets run by regional transmission organizations (RTOs) and independent system operators (ISOs). If the NOPR is adopted as proposed, storage would be eligible to provide all capacity, energy and ancillary services in such markets. The problem storage faces trying to participate in such markets today is the rules were developed for power plants and demand response companies and may unnecessarily limit the scope (and therefore compensation) of storage services. Most comments received by FERC in response to the NOPR were favorable — the comment window closed in February 2017 — but the proceeding was placed on hold while FERC sat without quorum for much of 2017. It remains to be seen whether the newly-reconstituted commission will pursue the NOPR.

The federal government also allows a 30 percent investment tax credit to be claimed on some storage facilities that are seen as part of solar and some wind projects. The key to eligibility is the storage equipment must be coupled to a renewable energy project and operated in a manner that it is considered power conditioning equipment or part of the generating equipment.

At least 75 percent of the energy stored by the storage device should come from the renewable generator to which it is coupled. A stand-alone energy storage project would not qualify.

Many state governments have enacted, or are in the process of enacting, mandates or regulations to promote storage. States will probably lead the charge on storage development in the near term since they have smaller constituencies and tend to be more flexible than the federal government in responding to market conditions. Some state and local governments also have a stronger appetite for renewable energy deployment than the current federal government. For example, the governors of 11 states and Puerto Rico and the mayor of the District of Columbia committed to comply with the Paris climate agreement after the Trump administration pulled out the United States [3].

In 2012, each of the three Military Departments announced that it would produce or procure 1 GW of renewable energy capacity by 2020 (Navy) or 2025 (Army and Air Force). Less than five years later, the Navy—with 1.25 GW of off-site and on-site capacity in place or in the pipeline—has already surpassed its goal; and the Army and Air Force are making steady progress toward their goals, largely by developing large-scale, on-site solar projects.

Other goals within DoD, including the desire to reduce utility costs, have been major drivers for project decisions. For example, when a Service contracts to procure off-site renewable energy, it counts toward the 1 GW goal and may lower the Service's utility costs; however, it does not enhance the energy security of the base(s) to which the power will be wheeled via the commercial grid. Moreover, even those projects that are located on-base are often not sited, sized, or designed based on security considerations. In many cases, the generation assets are connected directly to the grid, leaving the base with no ability to access the renewable energy during a power outage.

1.4 DEFINITIONS

Throughout this report, specific language is used to refer to various use cases and scenarios. The following definitions apply throughout:

Baseline microgrid is also known as the baseline microgrid under variable load. It represents the modeled microgrid results provided by ESTCP for each installation using existing on-site assets (PV, diesel gensets). The baseline microgrid is NOT the specified performance requirements for critical load coverage.

Behind-the-meter (BtM) refers to the operation of the microgrid including performance of ancillary services or demand charge reduction behind the meter (within the installation);

In front of the meter or ***Wholesale Market*** refers to microgrid operation in which services are provided by on site assets (located behind the grid interconnect) to the external utility grid, such as wholesale market participation or grid ancillary services.

2.0 TECHNOLOGY DESCRIPTION

Six different representative energy storage technologies were selected and utilized in modeling efforts to design an optimized microgrid. Each of these core technology types were selected based on their ability to excel in one or more of the six key performance attributes: coverage, availability, reliability, duration, ride-through capability, and stacked-value. Basic technology characteristics are summarized in Table 1. Additional details are provided in Appendix A1.

These technologies have been applied in microgrid design and storage implementation in numerous applications outside of DoD. The core suite of storage systems was specified to represent the range of commercially available energy storage chemistries and technologies in the market, and then evaluated using the ASU-XENDEE optimization software and modeling tools in various configurations (standalone, combined). This approach also enables the implementation of the most appropriate storage technology type for each installation based on site characteristics, local markets, and needs. However, note that the modeling, design, and dispatch approach demonstrated here is ES-technology agnostic, and can be used to consistently evaluate a wide variety of potential candidate technologies beyond those evaluated here.

Specific technologies evaluated for this project are:

- Maxwell Technologies – Ultracapacitor: Maxwell is a global storage leader with a primary focus on ultracapacitors - energy storage devices that are characterized by high power density, long operational life, the ability to charge and discharge very rapidly, and reliable performance at extreme temperatures. Maxwell ultracapacitor products have provided energy storage and power delivery solutions for applications in many industries, including automotive, heavy transportation, renewable energy, backup power, wireless communications and consumer and industrial electronics.
- AllCell Technologies – Li-ion: AllCell has developed li-ion batteries that integrate their patented PCC thermal management technology. This technology is based on the use of phase change materials to surround each li-ion cell, absorbing and conducting heat away to dramatically extend the life of the cells and prevent fire or damage to the battery.
- Blue Planet Energy – $LiFePO_4$: Blue Planet's Blue Ion 2.0 $LiFePO_4$ battery, known for leading safety performance and features, is a high efficiency LFP storage option. The system is scalable in 8 kWh increments to a maximum 448 kWh. Blue Ion's stabilized redox energies also aids in fast ion migration, allowing this system to be useful as mission critical energy backups, micro-grid communities, or for commercial and residential applications.
- NGK - NAS Energy Solutions – NaS: NGK's NAS sodium sulfur battery system has over 15 years of proven commercial operation, with 530 MW and 3.7 GWh of electricity stored today across 200 locations.
- Eos Energy Storage – Aqueous Zn Hybrid: Eos has developed a zinc hybrid cathode battery technology that is inexpensive, robust, scalable, and achieves a long operational life. They have recently deployed a 250 kW / 1 MWh system for Public Service Electric and Gas Company in Caldwell, NJ. The microgrid system includes the Eos energy storage system and an 896 kW-DC solar PV system.

- Avalon Battery – Vanadium Flow Battery: The Avalon™ Flow Battery, with its proprietary vanadium-based chemistry, is the world's first totally turn-key, fully-integrated flow battery. The AFB ships from Avalon's factory 100% functionally tested, requiring no ancillary systems, secondary containment, electrolyte filling or secondary electrical connections on site. This configuration allows site costs to be kept to an absolute minimum, and yields installation times of less than two hours per unit. The base unit has rated power output of 10 kW and storage capacity of 30 kWh.

2.1 ADVANTAGES AND LIMITATIONS OF THE ENERGY STORAGE TECHNOLOGIES

The comprehensive platform developed for and utilized during Phase I provides a tailored energy storage solution for any installation by considering climate zone, local energy market, and location specific use cases – customized and optimized to each application using a modular technology approach.

2.1.1 Energy Storage Hardware

Section 2.1 identified the core ESS technology types selected for Phase I and the selection rationale for each. The details for each ES technology, including: hardware specifications (including balance of plant), operations and maintenance requirements, component replacement cycles, and operational constraints to full utilization are summarized in Table 3 and detailed in Appendix A1, Table A-1. Details regarding the full microgrid system installation requirements and details are provided in This data has been assembled from a collection of public data and data disclosed to SR under vendor NDAs and approved by vendors for public release.

It should be noted that Ultracapacitors are a unique ES technology within this group with different characteristics than the other technologies. As noted in Table 3, the round-trip efficiency (RTE) can be quite variable. Although, under ideal conditions, ultracapacitor RTE can be superb – between 95-99%, in real world operation, RTE can be affected by discharge rate, thermal management during discharge, ultracapacitor design, and other factors, resulting in significantly decreased RTE. In addition, because of the incredibly fast response rate and ability to discharge rapidly, the C-Rate for an ultracapacitor is of little use. Typically, when integrated in an electrical system, the response rate of the ultracapacitor is limited by the response rate and performance of the balance of system, including inverter and switchgear.

The BOS hardware cost is calculated based on industry average costs breakdown of a utility-scale energy-storage system [4]. The Balance of System costs include the following items: climate control, containerization, controller and controls, and inverter. The total installation cost modeled is the sum of the storage unit cost and the BOS hardware cost.

Table 3. Battery Technology Specifications

	AllCell	Blue Planet	Eos	NGK	Avalon	Maxwell
Round-Trip Efficiency	0.9	0.98	0.75	0.75	0.8	0.85-0.95
Decay [fraction of batt capacity per day]	0.01	0.000333	0.24	0.12	0.003**	0.15
C-Rate	3C/2	1C	C/4	C/6	C/4	BOS limited
Minimum/Maximum SOC [fraction of batt capacity]	0.05 / 0.85	0 / 1	0 / 1	0 / 1	0 / 1	0/1
Discrete Unit Size [kWh/kW]	320/480	450/450	600/150	1200/200	30/7.5	165/1300
Storage Unit Cost [$/kWh]$^{+}$	350	650	240	318	563	150
BOS Hardware Cost [$/kWh]	343	343	343	343	343	N/A
Total Storage System Cost [$/kWh]	693	993	583	660	906	N/A
O&M Cost [$ per kWh capacity per month]$^{++}$	$1000 per year per site	0.333**	0.333	0.528	0.333**	
Lifetime [years]$^{+++}$	5	21	15	15	25	15

**Not provided by vendor - based on assumptions for similar technologies

$^{+}$ All costs are current (2020) costs. All systems are currently commercially available. Although cost reductions are anticipated, it is expected that cost reductions would be similar for all technologies, eliminating a need to model projected 2025 costs.

$^{++}$O&M costs are current (2020) cost estimates.

$^{+++}$Lifetime estimates are calculated based on total number of cycles in system lifetime. This is the basis for vendor warranty and service.

Table 4. Energy Storage System Installation Details

	AllCell	Blue Planet	Eos	NGK	Avalon
System Hardware	Custom packaged multi cell unit, container, passive thermal management	Standard battery package sizes, enclosure, thermal management	Standard battery package, container, climate control	Standard 1200kWh battery package, 20 ft ISO container, thermal management system	Standard 10kW battery package, full enclosure
System Software Included	Proprietary battery management system	Proprietary battery management system	Proprietary battery management system	Proprietary battery management system	Proprietary battery management system
Balance of System					
Inverter	Customer Specified	Customer Specified	Customer Specified	Customer Specified	Customer Specified
Control Technologies (Market Participating)*	Custom ASU-XENDEE MPC microgrid controller	Custom ASU-XENDEE MPC microgrid controller	Custom ASU-XENDEE MPC microgrid controller	Custom ASU-XENDEE MPC microgrid controller	Custom ASU-XENDEE MPC microgrid controller
Operational Information					
O&M Requirements	Vendor Specified	Vendor Specified	Vendor Specified	Vendor Specified	Vendor Specified
Operational Constraints (Temperature / Ramp Rate / Other)	-20C to 60C; storage to 40C charge/ discharge 0C to 40C	-20C to 50C; Storage to 45C	10C to 45C	Operating Temp 280C to 360C Ambient Temp -30C to 50C	-20C to 45C
Replacement Cycle (years)**	5	21	15	15	25

*Market participating microgrid controls are based on the ASU-XENDEE modeled dispatch algorithms, which will be fully developed and implemented in a commercial controller in Phase II.

**Replacement cycle of cells or full system is dependent on individual system design and drives warranty

The following process was used to develop an average BOS cost for the suite of energy technologies evaluated.

1. GreenTech Media's Battery Pack Cost and BOS Hardware Cost values for 2017 were used to calculate a ratio of BOS cost to Battery Pack cost.
2. The vendor provided battery pack capital cost was multiplied by this ratio.
3. The BOS costs for each vendor were averaged. (Average BOS cost = 343.2919 $/kWh)
4. The vendor provided battery pack capital cost was added to the average BOS cost to give the modeled installation cost as seen in Table 3.

Total installed costs were compared to market values for entire systems. The GreenTech Media report specifies average costs for utility scale storage systems (2017) as $587/kWh [18]. EIA reports range from $399/kWh (long term storage) to $2597 / kWh [20], with an average around $1100/kWh. DOE and NREL report storage costs associated with integrated PV-battery storage systems of $380-895 / kWh depending on storage duration, with battery pack costs averaging $209/kWh [19]. By comparison, the technologies modeled are mostly higher in terms of battery pack costs, but total installed costs are within the ranges specified in these references, which are based primarily on market surveys or user supplied information. With current wide variability in ESS costs, we believe the range of technology costs modeled provides a representation of a range of viable ESS costs.

In terms of battery specification, in addition to capacity, power, battery life, and costs, C-rate is an important measure of battery performance. The C-rate is a measure of the rate at which a battery is discharged relative to its maximum capacity. A 1C rate means that the discharge current will discharge the entire battery in 1 hour. For a battery with a capacity of 100 Amp-hrs, this equates to a discharge current of 100 Amps [21]. Most batteries can perform on demand at a range of C-rates, however, their performance is optimized at a specific C-rate that results in improved capacity and battery life. The batteries selected here were identified, in part, to cover a broad range of optimal C-rates.

In summary, the variety of technologies evaluated provide a wide range of performance benefits, and associated limitations or drawbacks. For example: the high C-rate technology from All Cell has a limitation on SOC compared to other technologies and a shorter life span for the battery cells; the Eos and NGK systems have higher decay rates than the other systems; the flow battery unit size is significantly smaller than other systems, while the NGK is much larger than others, potentially limiting application for certain sites. Blue Planet has a high efficiency and cycle life that is reflected in the higher cost. ***Each of the advantages and limitations are quantitatively expressed and evaluated to select the optimum HESS microgrid design for each site-specific requirement***.

2.2 RISKS ASSOCIATED WITH THE TECHNOLOGY

All battery technologies have associated risks. Of primary concern with lithium ion-based battery systems is thermal management and the potential for thermal runaway and fire. Each technology selected has specific technology developments to address thermal management and fire risk, but this is a common risk or safety concern across all such lithium batteries. A summary of the risks associated with each ES technology evaluated is provided in Table 5, including technology risks, as well as risks associated with technology maturity and availability.

Table 5. ESS Technology Risks

Technology	Maturity	Performance & Safety Risks	Sourcing	Scalability
AllCell	Cell and thermal management technology are mature. Full integrated energy storage systems are custom designed solutions, currently, with currently limited market penetration.	AllCell's technology uses phase change material to provide effective passive thermal management and fire suppression capability at cell level, improving safety and potential thermally driven performance issues. Limited risks.	Battery technology is off the shelf, provided by AllCell. Custom energy storage systems also available from AllCell.	Fully scalable. Allcell shipped over 16MWh of battery packs in 2016.
Blue Planet	Currently selling commercial systems. Over 100 current commercial installations.	$LiFePO_4$ composition provides improved safety in regards to thermal issues associated with standard Li batteries. Blue Planet provides a 15 yr manufacturer warranty, with a 21 year expected cell life (8000 cycles at 100% discharge), limiting performance risks.	Commercial, off the shelf systems from Blue Planet and distributors.	Standard modules (8, 16, 30, 60 kWh) enable custom storage system sizing and scaling (up to 450 kWh single integrated systems).
EOS	Currently selling commercial systems. Initial Aurora Gen 2.0 systems installed (<20), incl. MWh scale.	Zinc based system enables use of nonhazardous, non-flammable electrolyte, eliminating fire safety and need for active heating and cooling, as compared to standard Li ion systems. Very limited safety risk.	Commercial systems available from EOS.	Standard modules available integrated into custom sized ES systems at various scales.
NGK	Currently selling commercial systems. Over 20 initial product deployments. Up to 1510 MWh capacity.	Risk exists from sodium/water reaction and is mitigated by alternate fire suppression and hermetically sealed cells. High operating temperatures (280-360C) may result in container temps >60C on the surface.	Commercial systems available from NGK.	Scalable, with standard 1.2MW/8.6MWh modules (20 ft containers) as basis.
Avalon	Currently selling commercial systems. Over 100 units installed, including 1.1 MWh system.	Flow battery technology limits fire potential. System performance does not degrade, and life is stated as 25 years, limiting reliability and performance issues. Potential minor hazards from system chemicals.	Commercial systems from Avalon	Scalable, with standard modules at 10kW/30kWh.
Maxwell	Currently selling commercial systems. Over 8 million devices installed in grid applications.	High reliability and round-trip efficiency associated with high charge/discharge rates and low O&M costs; lower long-term storage round trip efficiency due to the nature of super capacity storage. Low risk.	Commercial systems available globally from Maxwell distributors	Highly scalable, from kW to MW size systems available.

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3.0 PERFORMANCE OBJECTIVES

Overall project objectives were stated in Section 1.2. Specific technology performance objectives are stated here. Five performance objectives were used to evaluate the ability for a storage enabled microgrid to provide energy security support for military applications.

- The first objective is the reliability to meet 100% critical load during a grid outage event. The metric used to evaluate if this objective was met is the probability that the critical load can be met at 168 hours and 24 hours. Data from the average annual critical load coverage probability curve was used to calculate this metric.
- The second objective is the reliability to meet 130% of the critical load during a grid outage event. The metric used to evaluate if the objective was met is the proportion of the critical load served for 168 hour and 24-hour outages. This was calculated by taking the average load served for a grid outage event starting at every hour of the year and dividing it by the total critical electrical load during that outage event.
- The third objective is the reliability to meet 10% and 30% of the critical load when no diesel fuel is available during a 24-hour grid outage event. The metric used to evaluate if the objective was met is the proportion of the critical load served for 10% and 30% levels when no fuel is available for 24-hour outages. This was calculated by taking the average load served for a grid outage event starting at every hour of the year and dividing it by the total critical electrical load during that outage event.
- The fourth objective is the net life-cycle cost of deployment and operation. The metric used to evaluate if the objective was met is the net cost of protecting each kilowatt of peak critical load. This was calculated by taking the difference of the 20-year net cost of the storage enabled optimized microgrid portfolio and the 20-year net cost of buying electricity from the grid and dividing it by the peak critical load demand and the 20-year duration of the project.
- The last objective is the fuel use reduction compared to the baseline microgrid when meeting a 100% critical load profile. The metric used to evaluate if the objective was met is average gallons of fuel saved during a 168-hour grid outage. This additional metric shows how a storage enabled microgrid paired with renewable generation can reduce fuel use and therefore increase the ability to serve the critical load for longer durations than a generator only microgrid.

Details regarding the sites modeled are provided in 4.0, with modeling approach, assumptions, and details provided in Section 5.0.

A summary of the performance objectives, specific requirements for critical load coverage for each site, baseline microgrid performance results provided by ESTCP, and complete results for modeled energy storage enabled microgrids, are provided in Sections 6.0 and 7.0.

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4.0 FACILITY/SITE DESCRIPTION

4.1 FACILITY/SITE LOCATION AND OPERATIONS

Five DoD installations with varying microgrid capacities were identified by ESTCP for Phase I modeling and analysis of the HESS approach. The five installations, for all of which sufficient data was available to conduct the analyses, provided a range of critical loads and microgrid capacities to represent many other DoD installations, and included the following:

- **Westover ARB -** The largest Air Reserve Base in the US. It is close to Springfield and within the city limits of Ludlow and Chicopee, in the southern part of Massachusetts. The facility is about to grow even more due to the 2005 BRAC (Base Realignment and Closure) commission, which ordered it to adopt another base located nearby.
- **Naval Base Ventura County** – A naval installation composed of three operating facilities - Point Mugu, Port Hueneme and San Nicolas Island located in a non-encroached coastal area of Southern California, NB Ventura Co. is a key element in the DoD infrastructure because of its geographical location.
- **Holloman AFB** - Currently home to the three major permanent units and one tenant foreign unit. The main unit of the base is the 49th Wing and its support groups; medical, materiel maintenance, maintenance, mission support and operations. Holloman Air Force Base is also home to the 4th Space Control Squadron, 46th Test Group and detachment of the German Air Force, the German Air Force Flying Training Center, which trains Tornado aircrews and pilots.
- **NAS Patuxent River** – Located in St Mary's Co., Maryland, NAS Patuxent is home to Headquarters, Naval Air Systems Command (NAVAIR), the US Naval Test Pilot School, the Atlantic Test Range, and serves as a center for test and evaluation and systems acquisition relating to naval aviation.
- **Fort Bliss** - comprised of over 1.12 million acres of land, with its main post located in El Paso, Texas. 90% of Fort Bliss training grounds, as well as several base camps, are located in New Mexico. Fort Bliss is home of over 38,500 active duty military personnel, as over 39,000 of these soldier's family members, and over 1,000 reservists. It is also the home of over 13,000 civilians.

Critical load and solar PV generating profiles for each of the installations are shown in Figure 1.

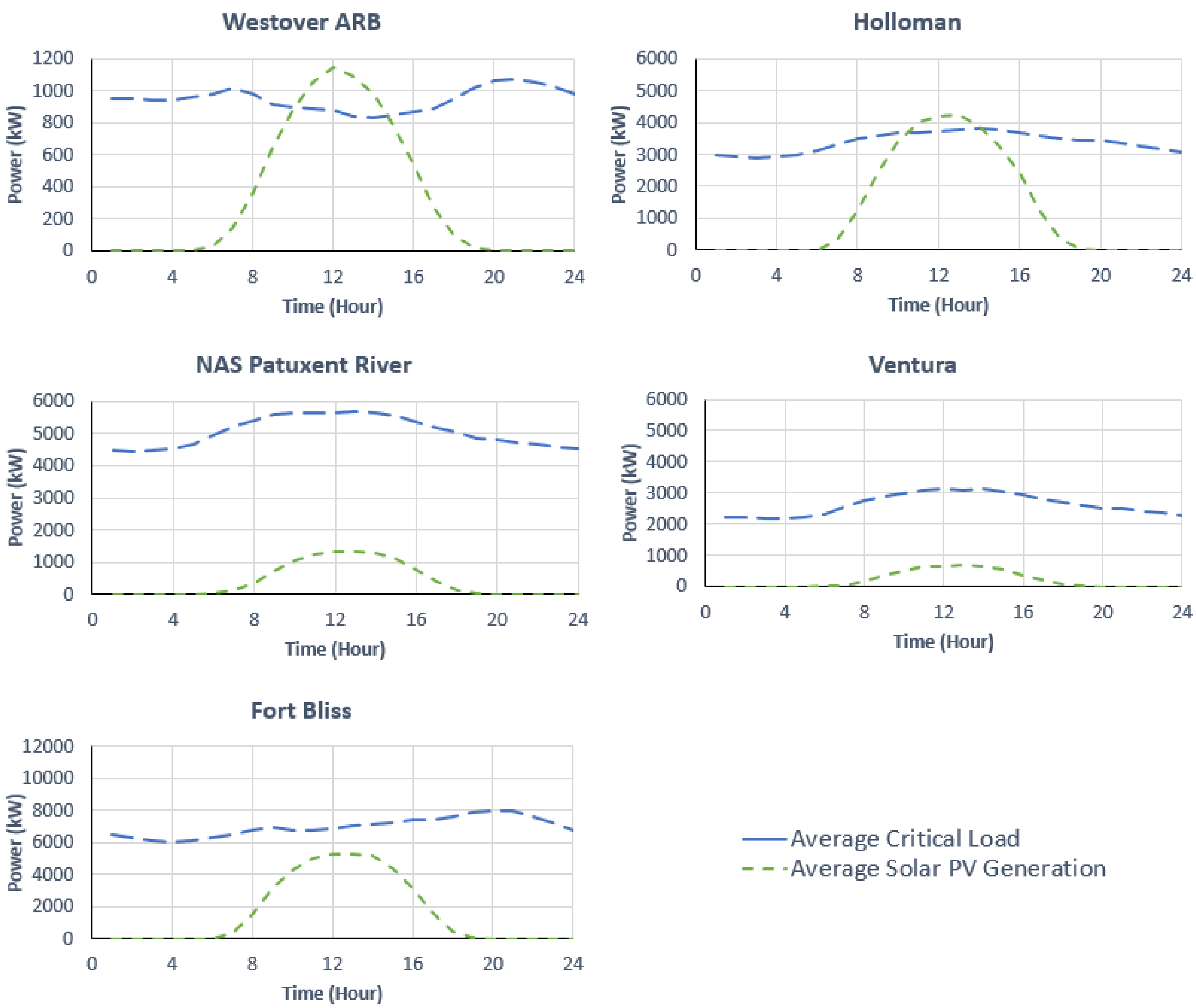


Figure 1. Average Annual 24-hour Critical Load and Solar PV Generation for the Five Bases.

Note: complete 8760-hr annual critical load and PV generation profiles were used in modeling. 24-hour averaged loads are provided for visualization.

Table 6 summarizes key demand, critical load, PV capacity, and annual electricity costs for the five bases.

Table 6. Demand and Capacity Summary of Modeled DoD Installations

Base	Maximum Critical Load (kW)	Critical Load Requiring Ride Through (kW)	Total Peak Demand (kW)	PV Capacity (kW-AC)	Annual Electricity Bill (million)
Westover ARB	1,707	900	3,414	2,000	$1.5
NB Ventura Co.	4,003	2,000	14,992	830	$7.2
Holloman AFB	5,996	3,000	15,990	5,000	$6.1
NAS Patuxent River	8,014	4,000	33,958	2,000	$17.8
Fort Bliss	12,507	6,000	67,605	6,200	$20.7

Additional selection rationale and site-specific benefits relevant to the study for each installation are summarized in Table 7.

Table 7. Installation Characteristics and Potential Microgrid Benefits

Installation	Selection Rationale & Characteristics of Interest	Potential Site Specific Benefits
Westover ARB	Smallest facility, with lowest annual electricity cost. Distinct use case scenario from larger facilities. Likely high cost structure from regional/local northeastern utility. Interaction with small regional/local utility is a unique case. High projected comparative solar capacity for small facility vs others.	High potential solar penetration with low critical load enables renewable plus energy storage microgrid to cover significant peak and critical load potentially. Improved economics due to this (reduced genset and UPS costs) plus potential regional higher costs.
NB Ventura Co.	Mid-sized facility. California market, with likely high electricity cost and unique pricing agreement. Low PV capacity (but anticipated significant potential). Low critical load as percentage of peak demand. Small ride-through requirement	Small ESS investment with potential significant impact on resiliency (ride through and critical load)
Holloman AFB	Significant PV resource as percentage of peak (33%) and critical (83%) loads and critical load ride through (167%). Large utility with demand and time of use charges.	Most potential for utilizing solar PV plus energy storage for supplying electricity for very large portion of load, as well as potential for full critical load, peak demand, and ride through for significant durations. Potential to significantly reduce diesel and UPS use.
NAS Patuxent River	Large energy consumer. Regionally unique (mid-Atlantic). Electric Cooperative supplier. Unique use case.	PJM market access and participation.
Fort Bliss	Largest energy consumer of group. Small critical load as percentage of peak demand, but largest critical load of all sites. Large, vertically integrated utility with multiple price structures. Unique use case scenario.	Provides a large facility scenario with significant peak demand and critical load. Potential for significant quantity of energy storage in microgrid, Opportunity to mitigate time of use and peak demand charges.

4.2 FACILITY/SITE ASSUMPTIONS AND INITIAL CONDITIONS

Information on the proposed energy storage technology solutions that were modeled for each installation are provided in Section 2. Representative diagrams of the proposed energy storage installations for each base are provided in Appendix A5. These diagrams provide representation of the baseline microgrid, including generation capacity (diesel genset and solar PV), UPS systems, critical loads, and proposed energy storage technology integration. Specific details regarding site critical loads, peak demand, PV capacity are provided in Table 6..

On site generator characteristics for each site are provided in Table 8, with UPS characteristics for each site also provided in Table 9.

Table 8. Site Diesel Generator Capacities

	Number of Diesel Gensets	Capacity of Each Diesel Genset [kW]	Capital Cost of Diesel Genset [$/kW]	Annual O&M and Testing Cost [$ per unit per year]	Diesel Fuel Price [$/gallon]	On-Installation Diesel Fuel Supply [gallons]
Holloman AFB	9	750	750	7,000	2.59	375,000
Fort Bliss	8	2000	600	20,000	2.59	750,000
NAS Patuxent River	12	750	750	7,000	2.74	500,000
NB Ventura Co.	7	750	750	7,000	2.97	250,000
Westover ARB	4	750	750	7,000	2.65	125,000

Lifetime for all generators is 20 years

Table 9. Site UPS Specifications

	# of UPS	Capacity & Duration of Each UPS	Capital Cost of UPS ($/kVA)	Fixed O&M Costs of UPS ($/kVA-year)	Variable O&M Cost of UPS ($/MWh)
Holloman AFB	13	250 kVA, 63 kWh	647	13.66	4.39
Fort Bliss	4	2,000 kVA, 500 kWh	486	5.98	1.21
NAS Patuxent River	17	250 kVA, 63 kWh	647	13.66	4.39
NB Ventura Co.	9	250 kVA, 63 kWh	647	13.66	4.39
Westover ARB	5	250 kVA, 63 kWh	647	13.66	4.39

Lifetime for all UPS is 20 years.

5.0 METHODOLOGY

The project team developed and utilized an optimized microgrid and energy storage platform with integrated analytics and controls to address Phase I objectives, evaluate potential HESS solutions at each of the five select DoD installations. Identified solutions and control strategies are also proposed for study and demonstration via hardware-in-the-loop (HIL) testing (Phase II) as well as potential field demonstration (Phase III). The comprehensive platform applied on this project can provide tailored energy storage solutions for any installation by considering climate zone, local energy market, and location specific use cases.

5.1 MODELING TECHNOLOGY OVERVIEW

The HESS integration platform used to conduct Phase I uses two primary technological components: (1) an analytics platform for microgrid design, energy storage integration, HESS optimization, and microgrid controls tailored to the site and its characteristics, along with (2) a core suite of energy storage technologies, providing a fully integrated solution – customized and optimized to each application using a modular technology approach. These technologies were selected as the basis of the HESS solution to be applied to the five installation microgrids selected for the Phase I study.

Specific technological advantages of the modeling and controls tools with respect to DoD microgrid relevance are summarized below:

- <u>XENDEE:</u> A secure cloud computing microgrid platform (XENDEE, 2017) implements QSTS power flow simulation, short circuit analysis, reliability analysis, arc-flash hazard analysis, impact load starting, and deploys the DER-CAM (Distributed Energy Resource-Customer Adoption Model) decision support tool to perform economic optimization for planning, design, and dispatch of microgrid projects. DER-CAM is a decision support tool that determines the optimal mix and capacity of the DERs, as well as the optimal dispatch of these resources, for a microgrid under different settings. DER-CAM is formulated as a Mixed Integer Linear Program (MILP), where the key inputs include customer loads broken into several end-uses; cost and performance characteristics of generation and storage technologies (e.g., investment cost, operation and maintenance costs, efficiency, heat-to-power ratio maximum operating hours, etc.); and electric and natural gas tariffs. The tool generates optimal investment and operation decisions, including annual energy costs and optimal DER capacities. Under this project, ASU has assisted in enhancing the abilities of DER-CAM in XENDEE with market-aware model predictive control (MPC) techniques.
- <u>ASU Energy Security Model (ESM):</u> A Python-based standalone model that, for our purposes, calculates microgrid energy security metrics (e.g. Critical Load Coverage Probability Curves). The model is computationally friendly enough to allow for use in real-time operational dispatch and microgrid controls that are performed during an outage to maximize the CLCPC subject to solar PV output, storage reliability, storage state of charge, generator reliability, and fuel availability. Utilizing the capabilities of ASU's ESM, the modeling within Phase I assessed microgrid performance in terms of reliability, resilience, the current Energy Security and Sustainability strategy, and Economics metrics (e.g. Levelized

Cost of Electricity (LCOE[2]), return on investment, payback). ASU's prior work using forecasting and Monte Carlo simulations for reliability modeling of hybrid microgrids provided statistical background for the work. ESTCP provided an alternative approach to all project teams using first fault trees and then Markov processes to describe reliability. ASU adapting each approach to implement storage into ESTCP's generator-only reliability equation sets and developed dispatch routines to maximize CLCP with respect to real-time and forecasted state conditions.

5.2 CONCEPTUAL METHODOLOGY

Our approach combines economic optimization through the XENDEE platform and ASU's energy security model (ESM) to evaluate energy asset portfolios for military microgrids. This method ensures energy security metrics are achieved while providing the lowest cost energy.

Our HESS solution aims to leverage the unique characteristics of multiple energy storage technologies to enhance the value that each individual technology can provide.

Figure 2 shows the general process used to select the optimal microgrid portfolio for each of the considered military installations. A high-level summary of the 5-step process is listed below with detailed descriptions of each step explained throughout Section 5.

1. Environmental, economic, operational, and storage specific data including information regarding the increase in energy storage expected life due to including ultracapacitors is inputted into XENDEE. (See section 5.2.1 for the general assumptions used in modeling and section 5.2.1.1 for ultracapacitor integration assumptions)
2. Run models for Storage Sizing for Outages Scenarios in XENDEE. (See section 5.4.2)
3. Run models for Storage Sizing for Economics in XENDEE, based on the ESS sizing results from the Storage Sizing for Outages run (Step 2), to fully assess and compare the economic viability of each microgrid portfolio to baseline scenarios. (See section 5.4.3)
4. The optimal microgrid portfolio calculated by XENDEE (the ESS sizing results from the Storage Sizing for Outages run (Step 2)) is fed into ASU's ESM to complete energy security performance evaluations. (See section 5.4.4)
5. If the microgrid portfolio does not meet the required energy security metrics, additional generator and battery capacity constraints are included in the XENDEE models and the process is repeated until the microgrid portfolio meets the energy security metrics.

The design process is complete and is repeated until the optimal microgrid portfolio for all five military installations is achieved.

[2] Levelized Cost of Energy (LCOE) – measures lifetime costs divided by energy production for a specific site or project via calculation of net present value of the total cost of building and operating a power plant (microgrid) over an assumed lifetime.

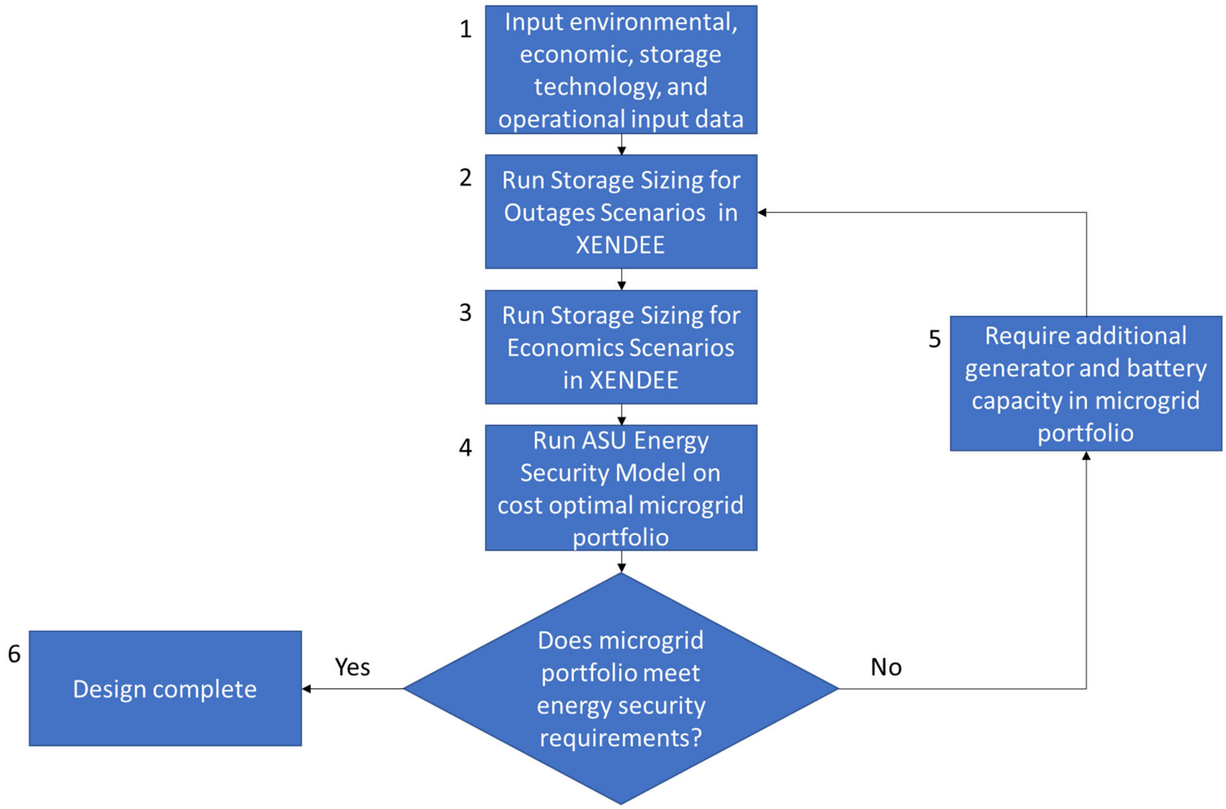


Figure 2. Process Flow Diagram Detailing the Steps Used to Calculate the Cost-optimal Microgrid Portfolio for Energy Security Operations of Each Base Considered.

XENDEE considers all costs associated with meeting system energy demand, including monthly fixed utility costs, volumetric electricity purchases, demand charges, annualized technology investment costs, and technology operation and maintenance costs (O&M) costs. XENDEE was used to establish the optimal storage capacity and operation required to achieve the energy security requirements and to assess the financial impact of implementing the resulting storage-enabled microgrid. All bases were modeled in four scenarios listed in Table 10 and below:

- A Current Operation scenario, modeling the bases as-is to verify modeling results against the provided data on total annual electricity cost;
- A Future Operation with PV scenario, modeling the bases with PV and diesel generators, UPS, and microgrid to establish reference points for financial metrics. This scenario is the ESTCP-provided baseline microgrid scenario;
- A Storage Sizing for Outages scenario to size the generators and storage necessary to meet critical load during outages while minimizing total annual energy costs; and

A Storage Sizing for Economics scenario, modeling the microgrid without outages to assess financial impact and value streams.

Table 10. Modeling Scenarios

Scenario	Purpose	Outages	PV	Generator Capacity	Generator Costs	UPS Costs
Current Operation	Validate model	None	No	Fixed to Existing Number of Units	O&M Costs	O&M Costs
Future Operation with PV	Establish reference costs	None	Yes	Fixed to Existing Number of Units	Capital Costs and O&M Costs	Capital Costs and O&M Costs
Storage Sizing for Outages	Determine optimal portfolio for reliability	36-day*	Yes	Sized by Optimizer	Capital Costs and O&M Costs	Capital Costs and O&M Costs
Storage Sizing for Economics	Assess financial impact of optimal portfolio	None	Yes	Minimum Set from Portfolio	Capital Costs and O&M Costs	Capital Costs and O&M Costs

*XENDEE software cannot directly model a 7-day outage in its current iteration. Therefore, 36 outage days (one outage day for each day type in each month) were used to ensure that the worst case 24 hour outage was considered and seven consecutive outages of the worst case were modeled.

For all scenarios, each military base is modeled as representative normal operation days constructed from the hourly data provided for gross total electricity consumption and PV output. For the Storage Sizing for Outages scenario, the load for representative outage weekdays, weekends, and extreme days was calculated by applying the percent of the gross total electricity consumption indicated as the critical load to each hour of the representative normal operation days.

Variations within scenarios also include representative profiles constructed from hourly data provided for real-time energy prices and ancillary service prices, as applicable. The utility costs are modeled by specifying the volumetric electricity and demand charge tariffs for each month, as well as the time-of-use (TOU) periods. PV purchases are priced the same as weighted average utility-provided electricity costs.

5.2.1 General Modeling Assumptions

All major modeling assumptions are summarized below:

<u>General:</u>

- One year of operation was modeled for all military base microgrids.
- A nominal investment discount rate of 6.0% was assumed.
- All bases were assumed to be grid-connected for all non-outage days, with electricity purchases available at the tariff and/or RTP rates specified in the military base data provided.
- Non-outage and outage days were modeled using representative days constructed from the gross electricity data and critical load data, respectively.
- Fixed charges and fixed discounts are considered explicitly in XENDEEs modeling of tariffs. Taxes and discounts that depend on consumption are modeled as part of the $/kw power or $/kWh energy charges.

XENDEE minimizes the total annual costs of providing energy services to a microgrid by optimizing the technology portfolio and operation for representative daily profiles. These 24-hour profiles, three for each month, represent typical weekdays, typical weekends, and extreme days. Decision variables, which describe the unknown quantities of a mathematical model such as the number of generators and their dispatch schedule, are optimized for each hour within each of the representative days. Monthly and annual quantities are determined by scaling up the daily variables using the number of days each representative profile occurs within a month.

PV generation:

- PV system capacity is modeled as the provided capacity in Table 6.
- Hour-to-hour PV system performance is modeled as monthly average 24-hour profiles constructed from the annual hourly PV output data provided.
- PV system installation and O&M costs are not considered in the modeling. Rather, the cost of PV generation is set equal to the cost of utility purchases. To model this, an offline calculation was made to determine a $/kW value to assign as an installation cost:
  - Run a baseline analysis without any on-site DERs. Load is met entirely by utility purchases. No outages are modeled.
  - Run a baseline analysis with PV, without generators, and without storage. Load is met by PV and utility purchases. No outages are modeled.
  - The difference in total annual cost between 1 and 2 is the reduction in utility purchases due to PV, and is used as an approximation for the annualized PV installation cost
  - The project interest rate and PV system lifetime are used to calculate the annuity rate for the PV.
  - Total upfront capital cost of the PV is calculated, using the Annualized PV Cost and the annuity rate
  - The installation cost of the PV is calculated, using the upfront capital cost and the PV capacity.

Diesel Generators and UPS:

- The provided generator cost and technical inputs were modeled, and are listed in Table 8 and Table 9.
- Generators are modeled as discrete units.
- Generators may provide both peak demand shaving and backup power during outages, and can provide demand response, where allowed by local market rules.
- Generators can provide emergency demand response.
- UPS was modeled with a fixed cost added to the microgrid, defined as an installation cost and an annual O&M cost, using data from ESTCP on UPS capacity and quantity.
- Generator and UPS costs and technical inputs are modeled as described in the Baseline modeling section.

The assumptions of the operational characteristics of generators can influence the optimal dispatch routine of a microgrid. Major assumptions and possible adjustments related to the operational characteristics of generators used in Phase 1 modeling include:

- Constant heat rate – The generator produces the same amount of power per unit of fuel consumed resulting in a constant efficiency.
  - Generators typically have a higher efficiency when operating near the nameplate capacity. The effect of this assumption will be explored in Phase II.
- No minimum loading – The generators are turned on at the beginning of a grid outage event and allowed to operate in an "idle" mode until power production is needed from them.
  - A more realistic assumption would be that the generators remain off until the current generators in use are at their optimal loading condition, at which point another generator is turned on to meet the increase in load. A minimum loading level (25% - 30%) will be explored in Phase II to prevent wet stacking.

Energy Storage:

- The battery state-of-charge at the start of a grid outage event is 50%.
- The battery SOC can vary between the minimum allowable SOC and the maximum allowable SOC when a grid outage event occurs. The starting SOC was calculated using a newly developed 8760-hour dispatch algorithm in XENDEE that optimizes operations to minimize operating expenses using the specified microgrid portfolio calculated in the Storage Sizing for Outages Scenarios. Using this approach links the on-grid economic operations with the off-grid energy security operations.
- Storage systems are modeled as discrete units, using vendor-provided technical performance data.
- Storage installation costs include the storage system unit, battery management system, the inverter, and all other balance-of-system (BOS) hardware costs. The total installation cost is input in terms of dollars per kWh of capacity. All costs and technical specifications for storage units were provided by storage manufacturer vendors, unless noted otherwise.
- ITC and MACRS incentives are applied in alternate scenario cases to demonstrate the potential impact of system design to enable access to such incentives. It is modeled as a 26% ITC and 85% depreciation at 5 years for MACRS. With the application of ITC, the storage is not allowed to charge from the utility - therefore, XENDEE restricts electricity for storage charging to be provided by either PV or diesel generators (during hours when diesel generators are allowed to operate). The federal tax rate assumed for monetizing the MACRS benefit is 25%.
- Ultracapacitor size was dictated by the existing UPS battery size.

In addition to the above assumptions, XENDEE pre-processes the generation (PV) and load data to simplify modeling and reduce computing power and time while providing quality results. The data preprocessing approach and assumptions are summarized below and in several references [22, 23, 24, 25, 26, 27].

- **PV** – For solar PV output, a single averaged daily profile is used for each month in the optimization. To obtain these average profiles, the mean over all days for each hour is calculated.
  - The impacts of this averaging process have been exclusively studied in three forthcoming papers from XENDEE, in addition to published references [22, 23, 24].

- **Load** – The load is organized into representative days for each month, which reduces the runtime of the optimization while maintaining the cost and size characteristic of the full time series. Three representative days are used for the typical, grid connected operation, while an additional three days are used to model off-gird operation. The three daytypes represent an average day on a weekend, weekday, and peak day for each month. The average week and weekend are calculated by splitting days within a month into either a weekday or weekend bin, depending on which day of the week they fall into. Within these bins, the same procedure used to calculate the PV system output (i.e. hourly average) is applied to create an averaged profile. The peak day is created by selecting the peak over the month that occurs in each hour as the load to be met in that hour. In this way, the demand peak is captured exactly for each month. For an outage day, either the same load profiles can be used, or a user specified load, which represents a different daily load, which can occur in response to the outage. The daytypes are projected into annual variables using a coefficient to describe how many days that daytypes is expected to occur within a given month.
  - Reduction of 8760 time series into representative days is a very common approach used in energy system planning, since the number of variables in the problem can become huge. [25, 26, 27]
- **Market price data** – Data from the time series are split into the representative data as described in the load section. However, instead of creating an artificial peak profile, the average week or weekday value was used on this day, depending on which day the peak would occur. In this approach, the extreme peaks that can occur due to market contingency or other unpredictable extremes are not considered as part of the planning optimization. XENDEE is researching this novel approach and plans to publish extensively in the coming fiscal years.

5.2.1.1 Ultracapacitor Integration Assumptions and Methods

The unique ride-through requirements of each base require an uninterruptable power supply (UPS) or comparable system be included in the asset portfolio. Ultracapacitors are commonly used for UPS applications due to their fast response times and relatively large power densities. Through collaboration with Maxwell and research of literature, our team has identified that ultracapacitors can not only provide the ride through requirements of a base but can increase the expected life of other energy storage technologies by smoothing the expected charging and discharging requirements[5-8]. Current literature shows that expected energy storage life can be extend by 10% - 80% when paired with ultracapacitors [9-15]. A sensitivity analysis was performed pertaining to the expected increase in life for each battery technology and the effect on the levelized cost of energy (LCOE) for Westover ARB. A conservative 20% increase in life was chosen for each battery technology for Phase 1 modeling. Detailed power engineering analyses and battery health models are needed to model the sub-second relationships between a ultracapacitors and longer duration energy storage technologies that was outside of the scope of work for Phase 1 but can be performed in Phase 2.

Modeling iterations were designed to pair various battery storage chemistries and technologies with ultracapacitors to enable full replacement of UPS systems, providing ride through capability as well as capability to provide additional services that UPS systems cannot provide.

Due to the timescale of data available, it was not possible to directly model and quantify the performance benefits of ultracapacitors. However, the economic benefits of ultracapacitors can be determined by comparing the equivalent installation cost of UPS systems, their relative O&M costs, and an assumed value from extending ESS life expectancy. The proposed HESS will be analyzed with and without ultracapacitors in order to demonstrate if there is or is not economic value gained through their addition.

In terms of ride-through capability, ultracapacitors typically are sized to provide an average of 1-minute of full ride-through capability. In applications where a 15-minute ride through is required due to primary backup power being provided by diesel generators, a simple replacement of a UPS system with an ultracapacitor would not be adequate, and cost limitations of ultracapacitors would limit the ability to size them for a 15-minute ride through capacity. However, when paired with a properly sized battery storage system, the combination of the ultracapacitor and battery can potentially provide the required ride through capability.

5.2.2 Sensitivity Analyses

A number of additional analyses and sensitivity analyses were completed to prevent modeling of scenarios that were not representative, allow for reduced modeling scope, and to gain a better understanding of microgrid operations under abnormal conditions. The Ultracapacitor ESS Lifetime Impacts, ESS Technology Combination Viability analyses were ran prior to other model runs to ensure valid assumptions for the primary modeling runs and account appropriately for specific potential variables. The Impact of PV Variability on ES Selection and Initial State of Charge Variability analyses were performed after the sizing of the microgrid portfolio to better understand the operational behavior of thy microgrid when operating outside of design conditions. Results are provided in Sections 6 and 7. These include:

5.2.2.1 Ultracapacitor ESS Lifetime Impacts

One military base, Westover, was chosen to perform a full sensitivity analysis around the lifetime extension from the ultracapacitor, testing lifetimes from 10% to 80%. All permutations described above were applied. Results are provided in Section 6.6.1.1.

5.2.2.2 Impact of PV variability on ES selection

Average monthly PV generation profiles, constructed as described in Section 5.2.1, were utilized for all primary modeling activities at each installation. To determine the potential impact of variability of PV generation output on energy storage technology selection and, ultimately, control and dispatch, a sensitivity analysis was completed. Minimum and maximum monthly PV generation profiles were constructed and utilized to evaluate the impact of worst-case and best-case PV generation. Representative minimum monthly PV generation profiles are constructed by taking the minimum values of the annual hourly PV output data and selecting the minimum for each hour from all days within the month. Similarly, maximum monthly PV profiles are constructed by taking the maximum values of the daily PV output data. This approach provides the best- and worst-case scenarios as boundaries to the resulting solutions. Results are provided in Section 6.6.1.2.

5.3 REVIEW OF BASELINE MICROGRID MODELING

Specific baseline modeling was conducted to establish reference points of comparison for financial metrics of the storage-enabled microgrids and compare the model to ESTCP provided baseline modeling results. Each military base was modeled with the exact number of generators and UPS specified in the ESTCP-provided data (Table 8, Table 9). The representative daily electrical loads for each month were generated using data from the provided hourly gross electrical consumption for each base. Utility rates were modeled as the existing utility schedules provided and no grid outages were modeled.

Two baseline microgrid models were created for each military base: a Current Operation scenario (existing assets only to compare to existing base electricity cost data) and a Future Operation with PV scenario (the ESTCP provided baseline microgrid). The purpose of the Current Operation scenario is to validate the fundamental model of each military base by comparing the modeled annual energy cost against the total annual electricity cost provided. To that end, no PV was modeled, O&M costs were modeled for the UPS and generator units, and no installation costs were modeled. Results are provided in 6.2.

The purpose of the Future Operation with PV scenario (ESTCP baseline microgrid) is to establish reference points for financial metrics of each military base if only the pre-planned PV and diesel generator capacity are installed. PV system capacity is modeled as the provided capacity in Table 6.. Both installation and O&M costs are modeled for the UPS and generator units.

5.4 STORAGE-ENABLED MICROGRID MODELING

The storage-enabled microgrid modeling includes two scenarios for each military base, Storage Sizing for Outages and Storage Sizing for Economics. Each scenario is run for each storage manufacturer, with costs and technical performance inputs discussed previously. The two scenarios are repeated with variations exploring the impact of increasing the storage lifetime with the addition of ultracapacitors/UPS, different market participation options (behind the meter vs wholesale market participation), and different pricing scenarios (current vs volatile).

5.4.1 Storage Sizing for Outages

The first storage-enabled microgrid modeling scenario was structured to assess the optimal technology portfolio required to meet the critical load during grid outages while minimizing costs. Military installation electric load on outage days is represented as the critical load, calculated as a percent of gross total electricity consumption applied to each hour. Representative outage weekdays, weekends, and extreme days are constructed from the annual hourly critical load. On modeled outage days, diesel generators, PV, and storage are required to meet the critical load.

The design space for the number of generator units and number of battery units was unbounded to allow for XENDEE to optimize the microgrid portfolio with respect to these generation and storage assets. Cost-optimal storage sizes and generator units were selected by XENDEE in the Storage Sizing for Outages scenario by modeling a 24-hour outage for each representative day in each month. Asset sizes were then fed into ASU's ESM for full outage modeling and analysis.

If the microgrid portfolio could not meet target ESTCP security requirements, then findings were returned to XENDEE with input conditions modified to increase constraints on minimum capacity for generators units and battery stacks. The new optimized microgrid portfolio from XENDEE was then sent back to ASU's ESM until target CLCP were met.

The starting state-of-charge (SOC) of energy storage also affects the ability of the microgrid to supplement a failure of an asset. The SOC of the energy storage (if it is included in the microgrid portfolio) is calculated using an hourly economically optimized dispatch algorithm in XENDEE. This algorithm calculates the dispatch and operating states of each asset within the microgrid portfolio to minimize operating expenses. The resulting SOC of this dispatch algorithm is fed into ASU's ESM to link the on-grid simulations in XENDEE and the energy security simulations in ASU's ESM.

For each military base, the Storage Sizing for Outages is repeated ten times: once for each storage manufacturer, assuming the lifetime listed in the storage parameters table, and once for each storage manufacturer with a lifetime extension of 20% from the addition of an ultracapacitor.

For military bases with ancillary service data (NAS Patuxent River, Ventura, and Westover), the spinning reserves prices were input as part of the representative normal operation day profiles, calculated from the provided annual hourly spinning reserve prices. For these bases, XENDEE optimized storage sizing for both capacity reserved for ancillary services on normal operation days and capacity used for dispatch to the microgrid on normal operation days and outage days.

Military bases with ancillary service data were also modeled in two permutations: one with a behind the meter install subject to utility rates, and one in front of the meter install subject to wholesale market participation. Considering the variations above, this totals to twenty modeled runs for NAS Patuxent River, Ventura, and Westover. For the wholesale market permutation, all utility charges (monthly fees, energy charges, and demand charges) are replaced by real time pricing (RTP), which are input as representative normal operation day profiles calculated from provided annual hourly RTP rates. Though, several utilities might still charge monthly fixed charges, these fees are small compared to energy prices, thus omitting them should have only small impacts on LCOE. In the Storage Sizing for Outages scenario, all RTP and ancillary service prices are the "current" data which was provided.

Wholesale market scenarios are expected to be wholly, or partly, owned by the local utility or other grid operator that has access to energy markets. An example is the MCAS Yuma microgrid with Arizona Public Service (APS) as the owner and operator [28]. The first off-take of power is by MCAS Yuma in the event of a grid outage or disturbance, thereby providing MCAS Yuma with resilience. During normal operations, APS can dispatch the microgrid to serve other loads or bid into energy markets. This improves financial efficacy of the otherwise lightly used generator assets. Further examples of this technical and contractual relationship are in planning stages or under contracting by various developers.

5.4.2 Storage Sizing for Economics

The second storage-enabled microgrid modeling scenario was structured to assess the economic impact of installing a microgrid sized for reliability. For each military base, the optimal storage and generator capacities that returned the lowest LCOE for each storage technology permutation from the Storage Sizing for Outages scenarios were chosen as the minimum required capacity for each respective technology. XENDEE chooses at minimum the number of diesel generators and storage units identified as the optimal technology portfolio, but also considers additional capacity if it will reduce the LCOE below the LCOE of the optimal technology portfolio microgrid design. For NAS Patuxent River, Ventura, and Westover, the selection was made from the Behind the Meter permutations to improve reliability performance, as they consistently selected higher storage capacities than the Wholesale Market permutations and participation in Wholesale Markets would require additional contractual agreements and financing mechanisms.

Future volatility of energy prices is assessed by modeling the volatile RTP and ancillary service prices. Volatile ancillary service prices are only provided for Westover, and volatile RTP prices are only provided for NAS Patuxent River, Ventura, and Westover.

5.4.3 Energy Security Modeling

ASU's ESM is used to model and evaluate the performance of each microgrid during the event of a grid outage. It uses a modified version of the Markov Chains approach detailed in "Calculating the Reliability of a Backup System" [16] that has been expanded to model the reliability of battery systems paired with generators. Equation 6 of "Calculating the Reliability of a Backup System" is modified to include that the probability of b batteries being available after d outage hours. Equation 1 below shows this modification where N_g is the total number of generators on site, g is a given number of generators, α_g is the failure to start of the generators, N_b is the total number of batteries on site, b is a given number of batteries, and λ_b is the failure rate of the batteries. This equation is used to calculate if the generators turn on and if the batteries are operational at the start of a grid outage. The failure rate was used instead of failure to start for batteries because the batteries are assumed to always be operational with respect to the up-time metric provided by the manufactures.

$$\boldsymbol{P(0, g, b) = \binom{N_g}{g}(1-\alpha_g)^g(\alpha_g)^{N_g-g}\binom{N_b}{b}(1-\lambda_b)^b(\lambda_b)^{N_b-b}} \qquad \textbf{(Eq. 1)}$$

Battery manufactures provided up-time/availability as the only quantitative metric available to express reliability of their battery systems (see Table A-1). The reliability function for the exponential distribution shown in Equation 2 was used to calculate the failure rate or MTBF equivalent (λ_b) with the assumption of a 168 hour outage (t). The resulting failure rates ranged from 0.000026 to 0.000052.

$$\boldsymbol{R(t) = e^{-\lambda_b t}} \qquad \textbf{(Eq. 2)}$$

Equation 7 of "Calculating the Reliability of a Backup System" was modified to include the chance of having b' available batteries next period, given b batteries, where g' is the number of generators available next period, given g generators, and λ_g is the failure rate of the generators. This equation is used to calculate the transition states between time steps.

$$\boldsymbol{p(g, g', b, b') = \binom{g'}{g} (1 - \lambda_g)^g (\lambda_g)^{g'-g} \binom{b'}{b} (1 - \lambda_b)^b (\lambda_b)^{b'-b}} \qquad \textbf{(Eq. 3)}$$

These new terms expanded the Markov matrix in Equation 8 of "Calculating the Reliability of a Backup System". Instead of the generator-only matrix sized $N_g + 1$ by $N_g + 1$, the updated formatulation with generators and storage is sized $N_g \times N_b + N_g + N_b + 1$ by $N_g \times N_b + N_g + N_b + 1$. These additional entries represent every combination of available generators and available batteries as operating states of the microgrid.

The last major modification to methods described in "Calculating the Reliability of a Backup System" pertains to Equation 9 expressing the survival criteria that selects viable system states. The survival criteria for a microgrid that uses both generators and batteries is shown in Equation 4 below. This equation expresses the initial condition where $G_{nom}^{cap}$is the nameplate rating of the generators, B^{cap} is the energy stored in the batteries, B_{min}^{cap} is the minimum allowable energy capacity of the batteries, B^C is the maximum discharging C-rate of the batteries, P_{crit}^{load} is the power consumption of the critical load, and P_{tot}^{sol} is the power produced by the solar PV array.

$$\boldsymbol{s_t(0, g, b) = \begin{cases} 0 & g \times G_{nom}^{cap} + b \times \min\left(B^{cap}(0) - B_{min}^{cap}, B^C\right) \geq \max\left(P_{crit}^{load}(0) - P_{tot}^{sol}(0), 0\right) \\ P(0, g, b) & g \times G_{nom}^{cap} + b \times \min\left(B^{cap}(0) - B_{min}^{cap}, B^C\right) \geq \max\left(P_{crit}^{load}(0) - P_{tot}^{sol}(0), 0\right) \end{cases}} \qquad \textbf{(Eq. 4)}$$

The chance of survival for each subsequent time step is then calculated Following the method described in Equation 10 of "Calculating the Reliability of a Backup System".

6.0 RESULTS & PERFORMANCE ASSESSMENT

6.1 PERFORMANCE OBJECTIVE RESULTS SUMMARY

Results for three scenarios evaluated are summarized in Sections 6.1.1, 6.1.2, and 6.1.3. Additional details and scenario analyses are provided in the remainder of Section 6. The three scenarios analyzed are:

- Design and optimization of energy storage enabled microgrid without incentives or optimization of additional solar assets (6.1.1);
- Design and optimization of energy storage enabled microgrid with ITC and MACRS incentives enabled for energy storage, but no optimization of additional solar assets (6.1.2);
- Design and optimization of energy storage enabled microgrid with ITC and MACRS incentives enabled, and optimization of additional solar assets (6.1.3).

All scenarios are compared to the critical load coverage probability requirements as well as the baseline microgrid performance. Inclusion of alternate scenarios in 6.1.2 and 6.1.3 are provided to demonstrate the potential impacts of other factors on optimal microgrid design.

6.1.1 Performance Objective Results Summary – ES-Enabled Microgrid – No Incentives

Results for critical load coverage objectives and net life cycle costs are summarized below for optimized microgrid design with:

- No application of incentives (ITC or MACRS)
- Incorporation of energy storage where economically viable
- Optimized diesel genset assets
- Participation in ancillary services market and BTM cost reductions allowed
- Wholesale market participation not included

The modeled Annual Net Protection Cost per kW of critical load (NPC) is summarized in Table 12. It should be noted that the modeled optimized microgrid allowed for reduction in the number of diesel generators, which is observed in the reduced total cost for sites compared to the baseline, including those sites where energy storage was not added.

The optimal microgrid designs produced by the XENDEE-ASU modeling approach for this scenario are summarized in Table 13 and Table 14 with the specific energy storage technology selected and other asset requirements identified. These asset portfolios provide the performance results specified in Table 11. For sites such as Ft. Bliss where multiple assets provide similar benefits, the values in Table 13 are only calculated using the single least annual cost ES technology solution with a specific amount of energy storage capacity and units. The results cannot be generalized for all storage technologies.

Table 11. Summary of Performance for Optimized Storage-enabled Microgrid - No Incentives

Performance Objective	Reliability to Meet 100% of Critical Load for 24 / 168 hr outage	Reliability to Meet 130% of Critical Load for 24 / 168 hr outage	Reliability to Meet 10% and 30% of Critical Load w/ no Fuel for 24 hr	Net cost of protecting each kilowatt of peak critical load ($/kW)	Fuel Use Reduction to Meet 100% Critical Load vs. Baseline Microgrid
Success Criteria	**Meets or exceeds reliability probability curve for baseline microgrid for 24-hour, 168-hour outages.**	**Probability to serve critical load 24-hour and 168-hour outages.**	**Probability to serve critical and ride-through load. No minimum standard.**	**Net cost is at or below level of baseline microgrid in current and future volatile scenarios.**	**Fuel use is at or below the level of the baseline microgrid.**
Objective Met?	Yes for Holloman, Patuxent (7d), Ft. Bliss	No Min. Standard. Results Below	No Min. Standard. Results Below	Yes	Yes for Patuxent and Ft Bliss
Westover ARB Requirement	99.84/95.08	NA/NA	0/0	See Table 12	NA
Westover ARB Results	96.87/81.77	56.48/18.53	0/0		0
Holloman AFB Requirement	99.04/78.58	NA/NA	0/0		NA
Holloman AFB Results	99.28/86.47	73.51/38.40	0/0		0
NAS Patuxent River Requirement	98.30/67.37	NA/NA	0/0		NA
NAS Patuxent River Results	98.12/80.88	49.62/5.65	0.16/0		5949
NB Ventura Co. Requirement	99.43/85.81	NA/NA	0/0		NA
NB Ventura Co. Results	97.03/67.88	32.59/0.0	0/0		0
Fort Bliss Requirement	99.25/82.25	NA/NA	0/0		NA
Fort Bliss Results	99.48/90.76	72.50/51.20	0/0		20807

Table 12. Annualized Net Protection Cost for Each Location Utilizing Optimized ES-enabled Microgrid, No Incentives, at Current Pricing.

Base	Scenario	Maximum Critical Load (kW)	Diesel Gensets	UPS	Microgrid	Energy Storage	Demand Response and Peak Shaving Savings	Ancillary Services and Wholesale Market Savings	Protecting each Kilowatt of Peak Critical Load
Holloman AFB	**Baseline**	5996	$49.38	$22.58	$36.39	$0.00	($10.00)	$0.00	$98.35
Holloman AFB	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	5996	$38.41	$22.58	$36.39	$0.00	($33.26)	$0.00	$64.12
Fort Bliss	**Baseline**	12507	$47.10	$18.15	$17.44	$0.00	$0.00	$0.00	$82.70
Fort Bliss	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	12507	$35.33	$17.89	$17.44	$3.77	($39.49)	$0.00	$31.17
NAS Patuxent River	**Baseline**	8014	$49.26	$22.09	$36.27	$0.00	($10.00)	$0.00	$97.63
NAS Patuxent River	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	8014	$36.95	$21.60	$36.27	$5.88	($27.73)	($0.71)	$66.37
NB Ventura Co.	**Baseline**	4003	$57.53	$23.42	$54.50	$0.00	$0.00	$0.00	$135.45
NB Ventura Co.	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	4003	$41.09	$23.42	$54.50	$0.00	($42.12)	$0.00	$76.89
Westover ARB	**Baseline**	1707	$77.09	$30.51	$85.34	$0.00	($27.00)	$0.00	$165.94
Westover ARB	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	1707	$38.54	$30.51	$85.34	$0.00	($24.63)	$0.00	$129.77

Table 13. Summary of Optimal Energy Storage Solutions for Each Site with No ITC or MACRS Incentives, Current Pricing Scenario, and Including Market Participation, Where Available.

Site	Energy Storage Capacity Specified (kWh)	Energy Storage Type
Fort Bliss*	900 1800 2400 960	BluePlanet Avalon Eos AllCell
Holloman AFB	None	
Westover ARB	None	
NB Ventura Co.	None	
NAS Patuxent River	450	BluePlanet

*Note that, at Fort Bliss, although the Blueplanet technology is selected as most optimal case at 900 kWh storage capacity, several other technologies were viable, with very little difference in economic performance (<0.5% difference in LCOE or NAC/kWPCL impacts), suggesting any technology could be utilized with similar critical load coverage reliability as well as economic impact. Details regarding the microgrid assets specified for each site where energy storage is viable under various scenarios with no incentives are provided in Table 14.

Table 14. Microgrid Design Specifications for Sites and Scenarios Where Energy Storage is Viable When No ITC or MACRS Incentives Are Applied.

In all other scenarios, no energy storage was specified by the XENDEE-ASU model.

Site	Technology	Scenario	Wholesale Market Participation	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacity [kW]	Total Storage Capacity [kWh]
Ft. Bliss	NA - Baseline	Current	NA	7	14000	6200	0
Ft. Bliss	All Cell	Current	NA	6	12000	6200	960
Ft. Bliss	Avalon	Current	NA	6	12000	6200	1800
Ft. Bliss	BluePlanet	Current	NA	6	12000	6200	900
Ft. Bliss	Eos	Current	NA	6	12000	6200	2400
Patuxent	NA - Baseline	Current	NA	12	9000	2000	0
Patuxent	BluePlanet	Current	N	9	6750	2000	900
Patuxent	BluePlanet	Current	Y	9	6750	2000	900
Patuxent	BluePlanet	Future Volatile	Y	9	6750	2000	900

Several observations can be made based on the specification of energy storage in the above scenarios and the lack of specification in all other scenarios:

- For Fort Bliss, it is apparent that technology selection has little impact on total annual energy cost or LCOE, as the amount of energy storage is relatively small when compared to generator and PV capacity. Therefore, ES system costs do not greatly impact overall economics;
- Any of the four identified ES technologies paired with an ultracapacitor or UPS would be viable at Ft. Bliss;
- For Ft Bliss, for similar reasons, the impact of ultracapacitors on battery system life has little impact on Total Annual Energy Cost or LCOE;
- For applications where existing PV assets are limited, where there is little opportunity for ancillary services or wholesale market participation, adding energy storage is not economically viable;
- For Patuxent, in all cases without ITC and MACRS incentives the model specifies a small amount of energy storage using the BluePlanet technology;
- The BluePlanet technology becomes viable in this application due to its high efficiency, low decay, and long life when compared to other storage technologies;
- With small amounts of energy storage added, in both locations, a reduction of one or two genset is possible;
- To optimize system economics, a reduction in number of gensets on site is warranted. However, this comes at the cost of a reduction in reliability (below N+1 reliability);
- The optimized microgrid can provide significant cost reductions compared to the baseline microgrid.

6.1.2 Performance Objective Results Summary – ES-Enabled Microgrid – With Incentives

Results for critical load coverage objectives and net life cycle costs are summarized below for optimized microgrid design with:

- Application of potential incentives (ITC or MACRS)
- Incorporation of optimized energy storage where economically viable
- Optimized diesel genset assets
- Participation in ancillary services market and BTM cost reductions allowed
- Wholesale market participation where allowable

Table 15. Summary of Performance for Optimized Storage-enabled Microgrid - With Incentives

Performance Objective	Reliability to Meet 100% of Critical Load for 24 / 168 hr outage	Reliability to Meet 130% of Critical Load for 24 / 168 hr outage	Reliability to Meet 10% and 30% of Critical Load w/ no Fuel for 24 hr	Net cost of protecting each kilowatt of peak critical load ($/kW)	Fuel Use Reduction to Meet 100% Critical Load vs. Baseline Microgrid
Success Criteria	**Meets or exceeds reliability probability curve for baseline microgrid for 24-hour, 168-hour outages.**	**Probability to serve critical load 24-hour and 168-hour outages.**	**Probability to serve critical and ride-through load. No minimum standard.**	**Net cost is at or below level of baseline microgrid in current and future volatile scenarios.**	**Fuel use is at or below the level of the baseline microgrid.**
Objective Met?	Yes, for all installations, when Inc are considered	No Min. Standard. Results Below	No Min. Standard. Results Below	Met for Westover, Holloman, Ft. Bliss.	Yes, for all installations, w/ optimized ES-microgrid
Westover ARB Requirement	99.84/95.08	NA/NA	0/0	See Table 16	NA
Westover ARB	100.00/100.00	94.74/85.89	100.00/59.45		
Holloman AFB Requirement	99.04/78.58	NA/NA	0/0		NA
Holloman AFB	99.96/96.93	99.5/61.07	97.53/0.00		
NAS Patuxent River Requirement	98.30/67.37	NA/NA	0/0		NA
NAS Patuxent River	98.12/80.88	49.62/5.65	0.16/0.00		
NB Ventura Co. Requirement	99.43/85.81	NA/NA	0/0		NA
NB Ventura Co.	99.63/89.10	66.80/3.64	96.39/0.00		
Fort Bliss Requirement	99.25/82.25	NA/NA	0/0		NA
Fort Bliss	99.97/98.10	79.03/63.77	0.15/0.00		

The modeled Annual Net Protection Cost per kW of critical load (NPC) is summarized in Table 16.

Table 16. Annualized Net Protection Cost for Each Location Utilizing Optimized ES-Enabled Microgrid, Including ITC and MACRS Incentives, at Current Pricing.

Base	Scenario	Maximum Critical Load (kW)	Diesel Gensets	UPS	Microgrid	Energy Storage	Demand Response and Peak Shaving Savings	Ancillary Services and Wholesale Market Savings	Protecting each Kilowatt of Peak Critical Load
Holloman AFB	**Baseline**	5996	$49.38	$22.58	$36.39	$0.00	($10.00)	$0.00	$98.35
Holloman AFB	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	5996	$32.92	$22.08	$36.39	$6.56	($31.99)	$0.00	$59.40
Fort Bliss	**Baseline**	12507	$47.10	$18.15	$17.44	$0.00	$0.00	$0.00	$82.70
Fort Bliss	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	12507	$35.33	$17.89	$17.44	$4.71	($39.17)	$0.00	$31.49
NAS Patuxent River	**Baseline**	8014	$49.26	$22.09	$36.27	$0.00	($10.00)	$0.00	$97.63
NAS Patuxent River	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	8014	$36.95	$21.60	$36.27	$2.45	($29.70)	($0.99)	$64.12
NB Ventura Co.	**Baseline**	4003	$57.53	$23.42	$54.50	$0.00	$0.00	$0.00	$135.45
NB Ventura Co.	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	4003	$41.09	$22.89	$54.50	$2.45	($42.57)	($0.54)	$75.38
Westover ARB	**Baseline**	1707	$77.09	$30.51	$85.34	$0.00	($27.00)	$0.00	$165.94
Westover ARB	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	1707	$38.54	$29.83	$85.34	$99.38	($0.78)	($233.65)	$18.67

The optimal microgrid designs produced by the XENDEE-ASU modeling approach for this scenario are summarized in Table 17, with the specific energy storage technology selected and other asset requirements identified. These asset portfolios provide the performance results specified in Table 15.

In all cases except for Westover, the selection of energy storage technology does not significantly impact the site annual electricity charges or LCOE (<1% impact), and any of the selected technologies with installed storage capacity indicated could be utilized. For energy security modeling purposes, the lowest cost ES system was used for analysis. In all such cases, that technology is BluePlanet with an ultracapacitor. For Westover, because of the large PV capacity and associated large optimal ES capacity, the ES system costs and characteristics result in differentiation of systems. In this case, Eos battery systems with an ultracapacitor are identified as the preferred system. The selected technology used for security modeling and additional analysis (the optimal microgrid design) is highlighted in green in Table 17.

Several observations can be made based on the microgrid asset specification and the economic and energy security performance in these scenarios:

- With inclusion of ITC and MACRS incentives, energy storage is viable at all installations in most scenarios;
- In most scenarios, the type of energy storage utilized has little impact on overall site microgrid economics because the amount of energy storage proposed is very small compared to grid electricity usage and diesel genset capacity.
- For similar reasons, the impact of ultracapacitors on battery system life has little impact on Total Annual Energy Cost or LCOE;
- Where the site has large ratio of PV capacity to load (Westover), the selection of ES technology can be optimized. In this case, the Eos system is selected for the optimal ES-enabled microgrid.
- Participation in the wholesale market can have significant impacts on overall site annual electricity costs and LCOE (i.e. reduction from $19M to $11.6M (volatile market) or $8.6M (current market) for Patuxent;
- Where participation in wholesale markets is available, the market scenario (current or future volatile) does not, however, impact the design of the microgrid and selection and sizing of optimal energy storage or other microgrid assets.

Table 17. Microgrid Asset Portfolio for Sites and Scenarios with ITC and MACRS Incentives Applied.

Site	Technology	Scenario	Wholesale Market Participation?	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacity [kW]	Storage [number of units]	Total Storage Capacity [kWh]
Ft. Bliss	All Cell	Current	NA	6	12000	6200	3	960
	Avalon	Current	NA	6	12000	6200	60	1800
	BluePlanet	Current	NA	6	12000	6200	6	2700
	Eos	Current	NA	6	12000	6200	4	2400
	NGK	Current	NA	6	12000	6200	3	3600
Holloman	All Cell	Current	NA	6	4500	5000	5	1600
	Avalon	Current	NA	6	4500	5000	104	3120
	BluePlanet	Current	NA	6	4500	5000	4	1800
	Eos	Current	NA	6	4500	5000	6	3600
	NGK	Current	NA	7	5250	5000	0	0
Patuxent	All Cell	Current	Y/N	9	6750	2000	3	960
	Avalon	Current	Y/N	9	6750	2000	73	2190
	BluePlanet	Current	Y/N	9	6750	2000	2	900
	Eos	Current	Y/N	9	6750	2000	4	2400
	NGK	Current	Y/N	10	7500	2000	0	0
Ventura	All Cell	Current	N	5	3750	830	0	0
	Avalon	Current	N	5	3750	830	15	450
	BluePlanet	Current	N	5	3750	830	1	450
	Eos	Current	N	5	3750	830	1	600
	NGK	Current	N	5	3750	830	0	0
Ventura	All Cell	Current and volatile	Y	5	3750	830	0	0
	Avalon		Y	5	3750	830	0	0
	BluePlanet		Y	5	3750	830	7	3150
	Eos		Y	5	3750	830	0	0
	NGK		Y	5	3750	830	0	0
Westover	All Cell	Current	N	2	1500	2000	0	0
	Avalon	Current	N	2	1500	2000	298	8940
	BluePlanet	Current	N	2	1500	2000	20	9000
	Eos	Current	N	2	1500	2000	14	8400
	NGK	Current	N	2	1500	2000	7	8400
Westover	All Cell	Current and volatile	Y	2	1500	2000	0	0
	Avalon		Y	2	1500	2000	298	8940
	BluePlanet		Y	2	1500	2000	19	8550
	Eos		Y	2	1500	2000	15	9000
	NGK		Y	2	1500	2000	7	8400

6.1.3 Performance Objective Results Summary – ES-Enabled Microgrid – With Incentives and Fully Optimized Assets Including Solar

Results for critical load coverage objectives and net life cycle costs are summarized below for optimized microgrid design with:

- Application of potential incentives (ITC or MACRS)
- Incorporation of energy storage where economically viable
- Optimized diesel genset assets
- Optimization of PV assets, including adding PV capacity
- Participation in ancillary services market and BTM cost reductions allowed
- Wholesale market participation where allowed

To evaluate energy storage asset specification in a scenario where the entire microgrid and all assets can be optimized, we evaluated three bases for optimal microgrid design. The optimal microgrid asset portfolio produced by the XENDEE-ASU modeling approach, when allowing for optimization of all assets, including PV along with diesel gensets and energy storage, results in improved economic performance in all cases. Optimal asset portfolios and evaluated metrics for this scenario are summarized in Table 18. A full analysis of all energy security metrics and economics was not completed.

Table 18. Optimized Microgrid Asset Portfolio and Performance when all Assets Are Optimized.

Component/Cost	NB Ventura Co. (Existing PV/Optimized PV)	NAS Patuxent River (Existing PV/Optimized PV)	Westover ARB (Existing PV/Optimized PV)
Diesel Generator	750 kW AC: 7 units / 5 units	750 kW AC: 9 units / 8 units	750 kW AC: 2 units / 2 units
Solar PV Generation	830kw / 3593 kW	2000 kW / 7252 kW	2000 kW / 2953 kW
Battery Storage	BluePlanet 450kWh / BluePlanet 1800kWh	BluePlanet 900kWh / BluePlanet 1350kWh	Avalon 8940kWh / Avalon 8940kWh
Ann. Electricity Cost	7858 /7786	17,675 / 16,719	867 / 754
168-hour CLCPC, 100% Critical (%)	89.10/98.82	80.88 / 86.26	99.99 / 99.99

Allowing flexibility in asset portfolio, including the potential addition of PV beyond existing capacity can have impact on overall system design and performance, including:

- Potential for significant additional PV and energy storage capacity observed at Ventura and Patuxent;
- Improvements in overall system economics, as evidenced by 1-13% reduction in annual energy costs depending on site;
- Improvement of over 6% in probability to cover 100% of critical load for a 7-day outage;
- A reduction of gensets is possible at sites with increased PV and ES.

6.2 MODEL VALIDATION & BASELINE MODELING RESULTS

To ensure the XENDEE-ASU modeling approach is valid, simulations were run to produce annual electricity cost values for each location for the existing facility, pre-microgrid. Electricity bill components were modeled using information provided by ESTCP. Table 19 shows the pre-microgrid electricity cost as provided as well as modeled in the XENDEE environment. Differences between reported and modeled values can be primarily attributed to the use of design days in XENDEE that were created from the 8760-hour data set ESCTP provided.

Table 19. Comparison of Modeled and Reported Results for Pre-microgrid Annual Electricity Costs.

	Holloman AFB	Fort Bliss	NAS Patuxent River	NB Ventura Co.	Westover ARB
Reported Total Annual Electricity Cost [k$]	6100	20700	17800	7100	1500
Modeled Total Annual Electricity Cost for Pre-microgrid [k$]	6123	22602	18214	7312	1581
Percent Difference	0.38	9.19	2.33	2.99	5.41

In addition, modeling was completed to produce 20-year net present cost values for the ESTCP-provided baseline microgrid as well as the pre-microgrid scenario (Table 20). An average difference 2.5% is observed for the baseline microgrid and 1.6% for the pre-microgrid system. Difference in values can be attributed to the use of design days and in-exact modeling of electricity bill components to be able to model in an optimization framework.

Table 20. Net Present Cost of Baseline and Pre-microgrid Infrastructure Modelled by XENDEE and Reported by ESTCP.

	Gen, UPS, and Infrastructure		Pre-microgrid	
Site	**ESTCP Reported Net Present Cost**	**XENDEE Modeled Net Present Cost**	**ESTCP Net Present Cost**	**XENDEE Net Present Cost**
Holloman AFB	$95,300	$92,499	$83,500	$83,494
Fort Bliss	$312,000	$309,069	$291,300	$291,461
NAS Patuxent River	$257,700	$260,729	$241,900	$248,366
NB Ventura Co.	$110,700	$106,021	$99,900	$99,708
Westover ARB	$26,200	$27,306	$20,500	$21,560

6.3 ENERGY SECURITY CONTROL AND DISPATCH

The control and dispatch of the designed microgrids influence the reliability and the probability that the critical load will be met throughout the duration of a grid outage event. The reliability of combined generator and battery microgrids is dependent on the total available generation capacity in the event of an energy asset failure during grid outage operations. If the total available generation capacity of the microgrid is reduced due to a failure of a generator, failure of a battery stack, insufficient fuel, or the discharging of batteries, the microgrid is less capable of meeting the net critical load. This indicates that the dispatch algorithm is a critical element in maximizing the reliability of a microgrid over the duration of a grid outage event.

Two dispatch algorithms were analyzed to understand the influence on microgrid reliability. The first dispatch algorithm employs optimization to minimize the fuel used over the duration of the outage. The critical load and solar PV generation profiles for a 168-hour gird outage event are fed into an optimization formulation that uses constraint equations for the energy balance of the microgrid and maintaining proper operation behavior of the energy assets. The second dispatch algorithm uses a logic-based dispatch to maximizes the total available generation capacity by using the excess solar PV generation and generator capacity to maintain the maximum allowable energy capacity of the batteries unless there is insufficient generation capacity to meet the critical load, at which point the batteries are discharged.

Figure 3 shows the average critical load coverage probability (CLCP) for a 168-hour outage with the 100% variable critical load level along with the required CLCP for each base. The fuel optimized dispatch algorithm does not meet the specified requirements for any of the scenarios because it discharges the batteries to minimize generator fuel consumption resulting in less total available generation capacity of the microgrid. For Holloman and NAs Patuxent, the fuel optimization algorithm discharges the batteries during the first couple of hours of the grid outage event to allow for excess solar to recharge the batteries. This reduction in available battery generation capacity decreases the probability that the microgrid will be able to meet the critical load in the event of a generator or battery failure. The optimized energy asset portfolio for Westover ARB and Fort Bliss include relatively large battery capacities when compared to the energy asset portfolios of the other three bases. This large relative battery capacity results in a higher average probability to meet the critical load over the duration of a grid outage event.

The CLCP displayed in Figure 3 shows that the storage enabled microgrid can meet or exceed the required CLCP when incentives are considered with a logic-based dispatch algorithm. However, if incentives are not considered the microgrid portfolio for each base does not meet or exceed the requirement during the full duration of the grid outage event. This indicates that the increased capacity of energy storage installed when incentives are considered provides increased energy security.

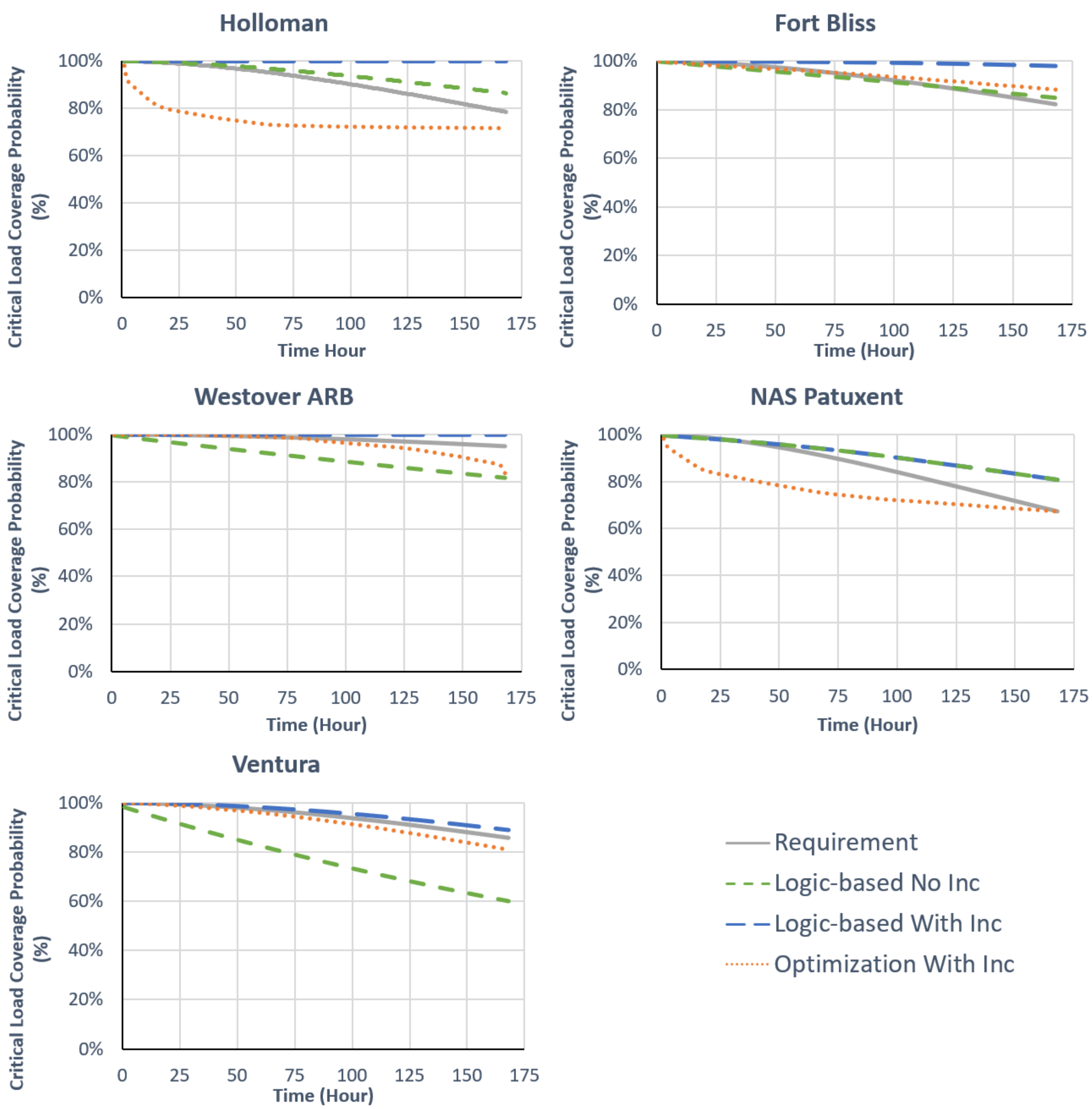


Figure 3. Annual Average Critical Load Coverage Probability Using an Optimization Base Dispatch Algorithm and a Logic-based Dispatch Algorithm for Microgrid Portfolios that Consider and Don't Consider Incentives.

6.4 ENERGY SECURITY PERFORMANCE

The microgrid portfolios that were generated when incentives were not considered did not meet the critical load coverage probability metric. Therefore, the microgrid portfolios generated when considering incentives are used in this section along with five scenarios to evaluate the performance of the optimal microgrid portfolios. These scenarios provide a better understanding of the ability of the optimized microgrid portfolios to meet the critical load demand under various conditions. The ride through requirements are assumed to be achieved during each scenario due to installing N+1 UPS as specified in the supplied data packets for each base or ultracapacitor systems. The five scenarios include:

- 100% Critical load for 168-hour outage
- 100% Critical load and no solar generation for 168-hour outage
- 130% Critical load for 168 hour and 24-hour outages
- 10% Critical load and no fuel for 24-hour outage
- 30% Critical load and no fuel for 24-hour outage

The three scenarios with durations of 168 hours are shown in Figure 4. Annual average critical load coverage probability with different critical load levels and solar PV generation, along with the performance of a generator only microgrid (baseline design) and the provided CLCP requirement.

Table 21 shows the average fuel used and proportion of critical load served for the various 168-hour outage scenarios. Important conclusions are:

- Under 100% critical load the optimized microgrid portfolio exceeds the requirements but often underperforms when compared to the generator only microgrid.
- This is primarily due to the baseline design having an N+1 generation capacity and the hourly variable critical load profile regularly being below the maximum critical load level, resulting in excess generation capacity being available in the microgrid.
- Three of the five storage enabled microgrids do not meet the CLCP requirements when solar PV generation is unavailable indicating that solar PV generation is needed to increase energy security of storage enabled microgrids.
- The storage enabled microgrids also become significantly less resilient when the critical load is increased by 30% because the ratio between total generation capacity to net load is decreased. This results in the microgrid being less able to supplement generation in the event of a generator or battery failure.
- If no failures occur, the microgrids can serve 127 - 130% of the critical load profiles for a 168-hour outage.

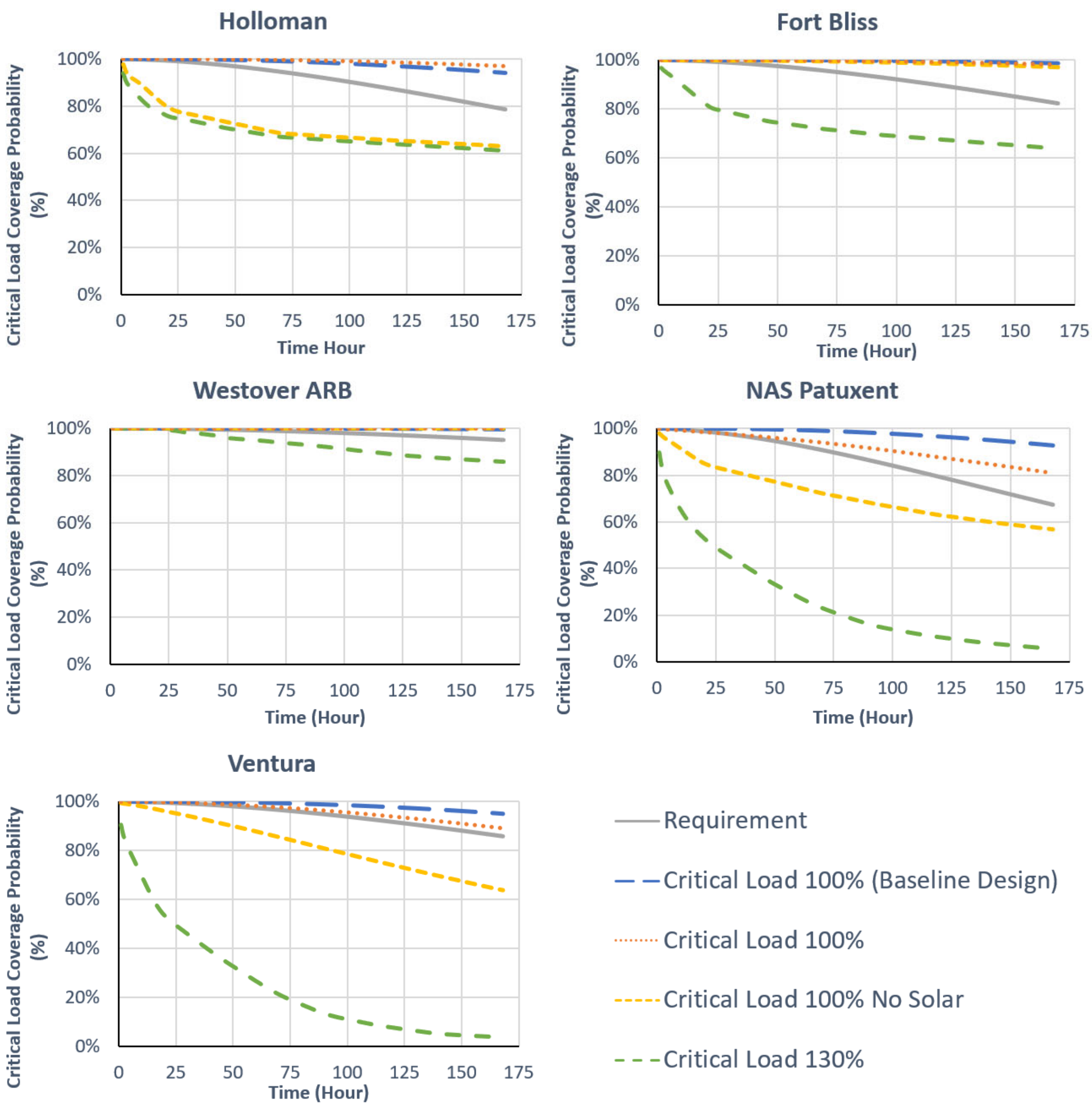


Figure 4. Annual Average Critical Load Coverage Probability with Different Critical Load Levels and Solar PV Generation.

Table 21. Summary of Fuel Consumption and Proportion of Critical Load Served for 168-hour Outages.

Base	Generator Only Average Fuel Consumption (gal)	Critical Load 100% Average Fuel Consumption (gal)	Critical Load 100% No Solar Average Fuel Consumption (gal)	Critical Load 130% Average Fuel Consumption (gal)	Critical Load 130% Average Proportion of Critical Load Served (%)
Westover ARB	13,792	13,817	15,458	15,557	100.0
Holloman AFB	49,161	32,661	48,836	45,429	99.2
NAS Patuxent River	73,643	67,694	73,413	87,556	97.8
NB Ventura Co.	38,299	35,362	38,316	46,371	98.9
Fort Bliss	89,758	69,042	89,898	95,285	99.7

The three scenarios with durations of 24 hours are shown in Figure 5, along with the provided CLCP requirement. Table 22 shows the average fuel used and proportion of critical load served for the various 24-hour outage scenarios. Each base maintains over 55% probability that they can meet the critical load when it is increased by 30% and provide 97.9% - 100% of the load on average for a 24-hour outage.

All of the storage enabled microgrids have a high likelihood to meet a 10% critical load profile for the first hours of a grid outage but the probability to meet the load decreases drastically as the battery capacity is depleted. Once solar PV starts to generate power, the excess solar can be used to charge the batteries and the probability to meet the critical load starts to increase due to having more total generation capacity in the microgrid and a small net load.

The 30% critical load scenarios show similar behavior as the 10% scenarios, but the increased load causes the batteries to deplete faster. This results in a reduced probability to maintain the load until solar PV generation ramps up and can recharge the batteries. This causes the CLCP to reach 0% for all of the bases other than Westover ARB because Westover ARB optimized portfolio consist of the largest ratios of battery capacity and PV capacity to average critical load.

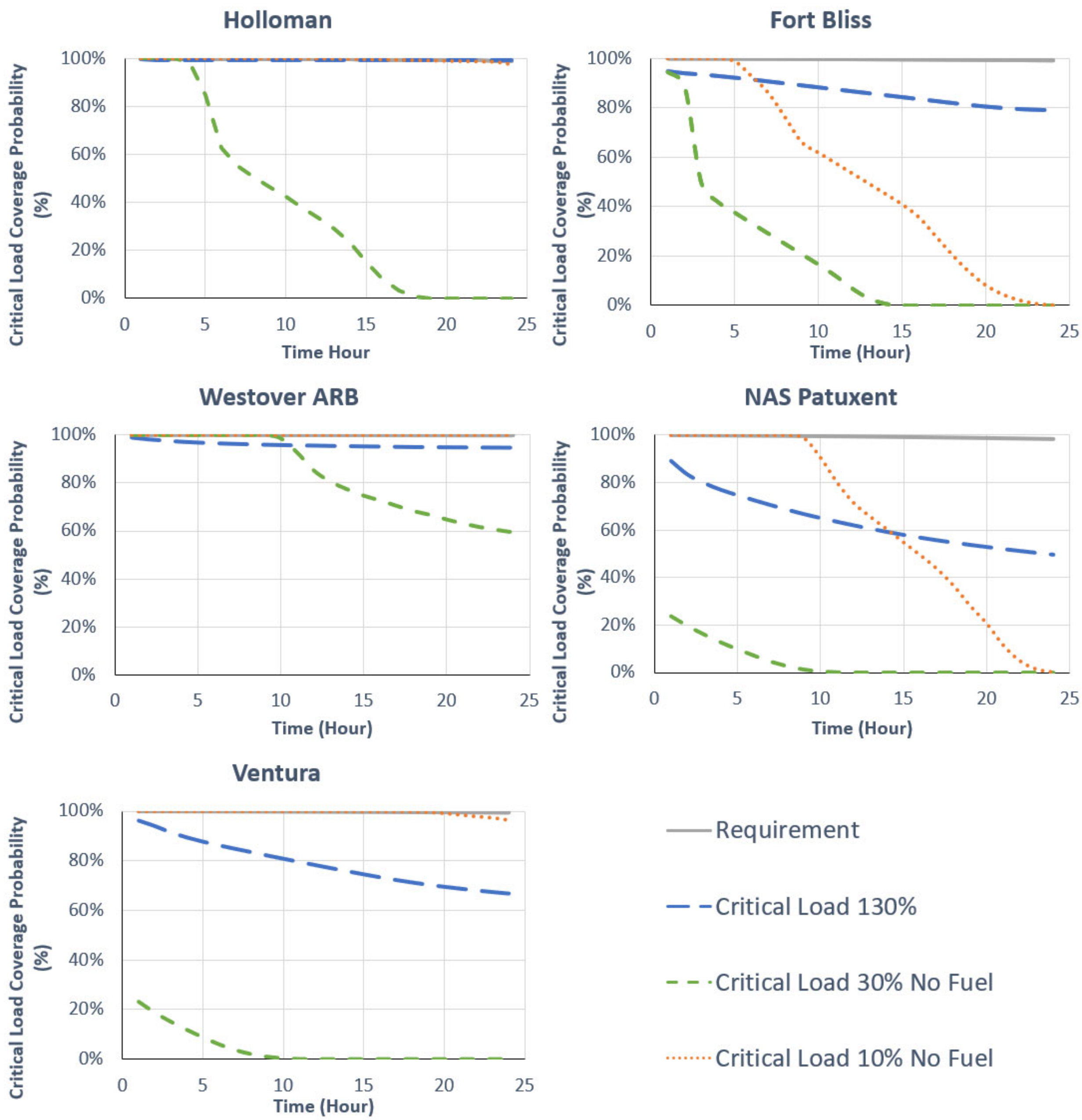


Figure 5. Annual Average Critical Load Coverage Probability for a 24-hour Grid Outage Event.

Table 22. Summary of Fuel Consumption and Proportion of Critical Load Served for 24-hour Outages.

Base	Critical Load 130 Average Fuel Consumption (gal)	Critical Load 130% Average Proportion of Critical Load Served (%)	Critical Load 30% No Diesel Fuel Average Proportion of Critical Load Served (%)	Critical Load 10% No Diesel Fuel Average Proportion of Critical Load Served (%)
Westover ARB	2,497	100.0	39.4	100.0
Holloman AFB	6,557	99.2	68.0	100.0
NAS Patuxent River	12,505	97.9	39.4	81.0
NB Ventura Co.	6,636	99.0	51.1	99.7
Fort Bliss	13,721	99.7	52.0	78.2

6.5 SYSTEM SIZING AND ECONOMIC IMPACTS

Figure 6 and Tables in Appendix A3 provide the optimal energy asset portfolio for each base resulting from the Storage Sizing for Outages scenario. These tables also provide details for each base regarding BtM and wholesale market scenarios including the following parameters: storage capacity, PV capacity, UPS, Diesel Gensets and costs, and HESS costs (including BOS and unit specifics). Also shown is the LCOE (without outages), with load met by a combination of DER generation and utility purchases.

For the scenario with no ITC or MACRS incentives, energy storage utilization was limited, due to the cost-effective diesel gen-sets and the prohibitive expense of the storage systems. Small amounts of energy storage were included in optimal microgrid designs for both Ft. Bliss and Patuxent. For Ft. Bliss, energy storage assets were specified from four different technology vendors, ranging from 900-2400 kWh of capacity. At Patuxent, a small amount of storage capacity is specified using the BluePlanet battery technology. Participation in wholesale markets had the largest impact on cost of electricity and annual net protection costs (see Table 12 and Figure 6. Optimal microgrid portfolio and levelized cost of electricity of each base modeled for each battery technology paired with a ultracapacitor/UPS system that can extend the expected life with no ITC or MACRS incentives), regardless of whether energy storage was present in the asset portfolio.

For comparison, models were also run with incentives included, which resulted in improved potential for energy storage deployment at every location (Figure 7). BluePlanet batteries were specified with the largest ES capacity at four locations, providing the lowest LCOE at three locations. High efficiency and long lifetime of this technology provide positive impacts on economics in most scenarios. However, as observed in the cases with no incentives, for four of the locations (all except Westover), the specification of energy storage technology did not significantly impact the NPC nor LCOE, due primarily to the small amount of storage specified as compared to overall electricity consumption. This can be attributed to relatively small capacity of solar arrays modeled in comparison to the average and peak demand of each base. If additional solar is considered, the storage technology and sizing would more drastically influence the LCOE (see 7.2).

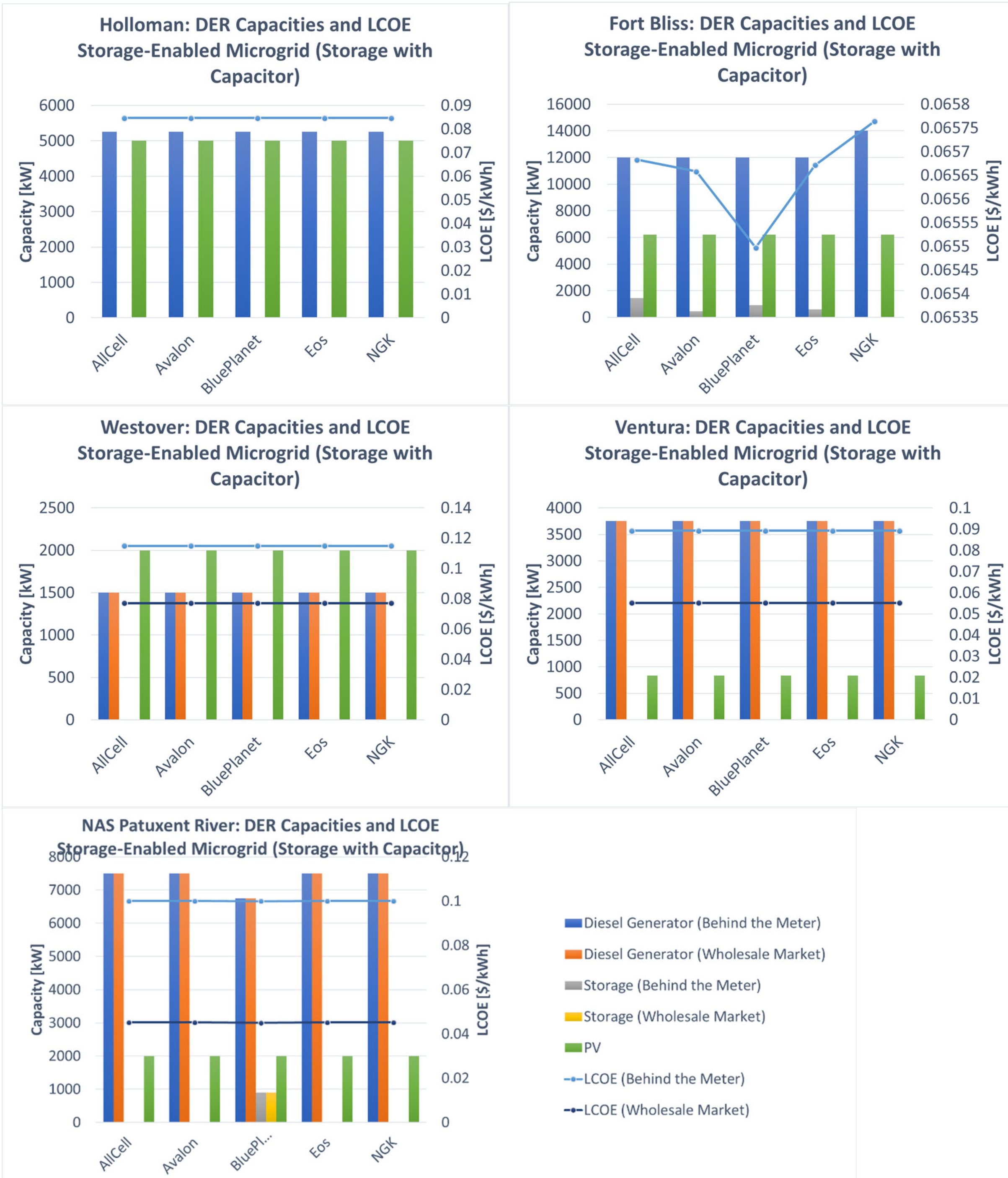
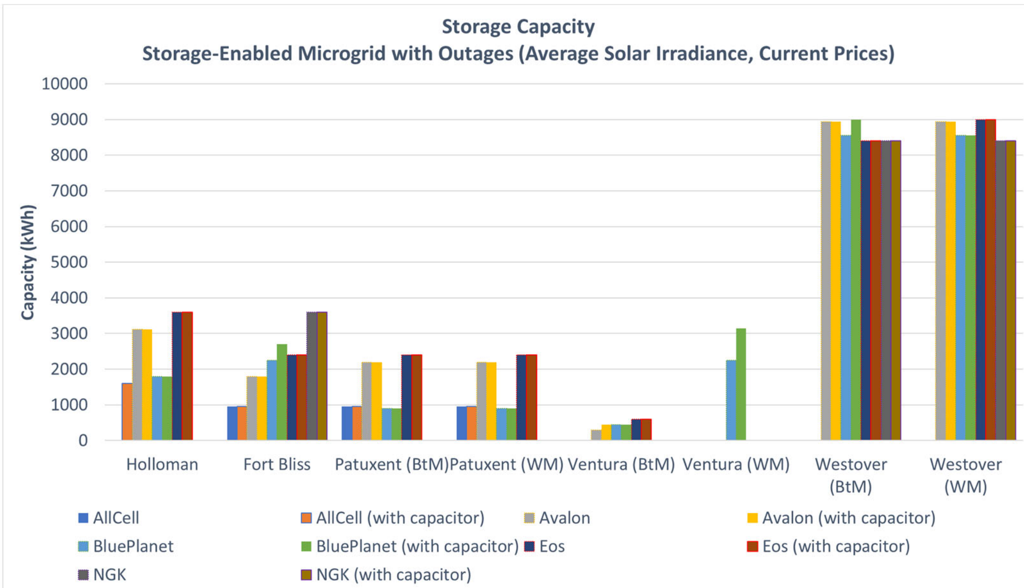


Figure 6. Optimal Microgrid Portfolio and Levelized Cost of Electricity of Each Base Modeled for Each Battery Technology Paired with a Ultracapacitor/UPS System that Can Extend the Expected Life with no ITC or MACRS Incentives.

Figure 7. Optimal Microgrid Portfolio and Levelized Cost of Electricity of Each Base Modeled for Each Battery Technology Paired with a Ultracapacitor/UPS System that Can Extend the Expected Life Including ITC and MACRS Incentives.

For Westover, a difference in impact can be seen among ES technologies, with Avalon battery technology providing the best economic results in its optimized microgrid design. Although, again, there were not major differences in NPC (Table 16) or LCOE (Figure 8) when comparing among Eos, BluePlanet, Avalon, and NGK at Westover. Westover ARB has the largest ratio of solar capacity to average electricity demand and as a result shows significant differences in LCOE for both the Behind the Meter case and the Wholesale Market case. This is an indication of the potential impact that proper sizing of PV generation along with ESS sizing and selection can have on overall microgrid economics – an important consideration for future microgrid design and specification.



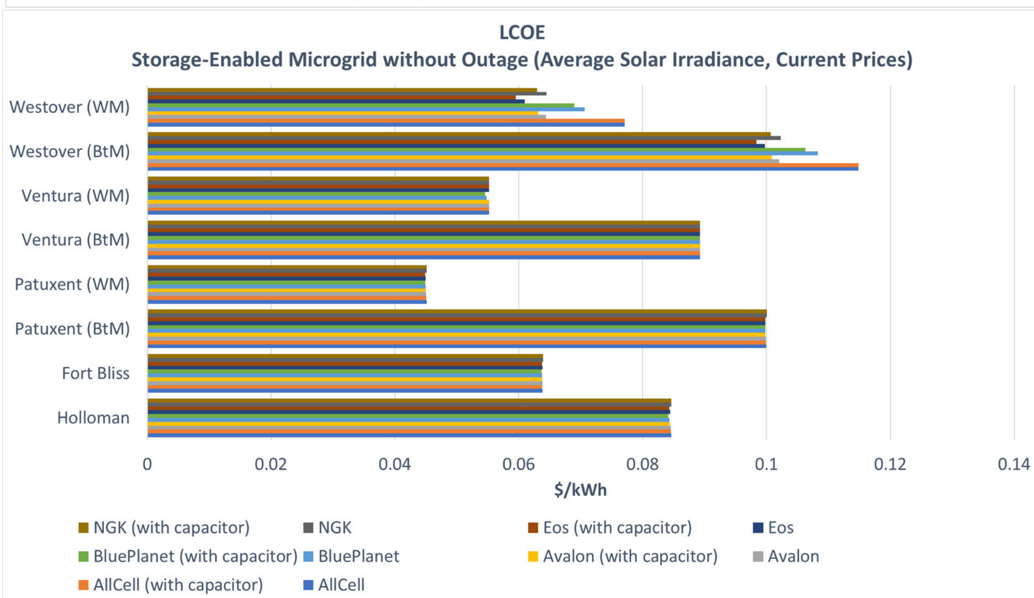


Figure 8. Storage Capacity and LCOE Values for Optimized Microgrid with Energy Storage at Each Location with ITC and MACRS Incentives Considered to Allow for Energy Storage Selection.

6.6 SENSITIVITY & SCENARIO ANALYSES

A number of scenario or sensitivity analyses were completed to determine potential sensitivity of modeling results to various parameters, to potentially allow for reduced modeling scope and prevent modeling of scenarios that were not representative. Results of specific scenario analyses are provided below.

6.6.1.1 Ultracapacitor ESS Lifetime Impacts

One military base, Westover ARB, was chosen to perform a full sensitivity analysis around the lifetime extension from the ultracapacitor, testing lifetimes from 10% to 80%. Results show that extending the lifetime of batteries can reduce the levelized cost of energy for the BluePlanet, Eos, and Avalon chemistries, primarily due to their already longer life. However, these reductions in LCOE are minimal (<1%). For AllCell and NGK technologies, there is almost no impact on economics with an increase in life. As a result, a conservative 20% increase was selected for modeling with ultracapacitors included based on discussions with Maxwell and minimal reductions of LCOE as seen in Figure 9.

Figure 9. Sensitivity Analysis Exploring the Relationship Between Expected Life of Energy Storage and Levelized Cost of Energy.

6.6.1.2 Impact of PV variability on ES selection

Average monthly PV generation profiles, constructed as described in Section 5.2.1, were utilized for all primary modeling activities at each installation. To determine the potential impact of variability of PV generation output on energy storage technology selection and, ultimately, control and dispatch, a sensitivity analysis was completed. Minimum monthly PV generation profiles were constructed and utilized to evaluate the impact of worst-case PV generation. Maximum monthly PV generation profiles were constructed for assessing best-case PV generation impact.

To examine the impacts of variability in solar output, two sensitivity scenarios were considered (see

Figure 10). Under these scenarios, additional investment in hybrid-storage technologies was allowed, however, ***no additional storage capacity was selected in any case***. Instead, the PV generation impacts the economics of the installation. Shown below, a common trend occurs, where applying the minimum PV output implies significant increases in energy costs, which directly translates to NPC. On the contrary, applying the maximum PV profiles results in only a slight decrease in annual energy cost and resulting NPC. Similar trends are observed if incentives are included as well.

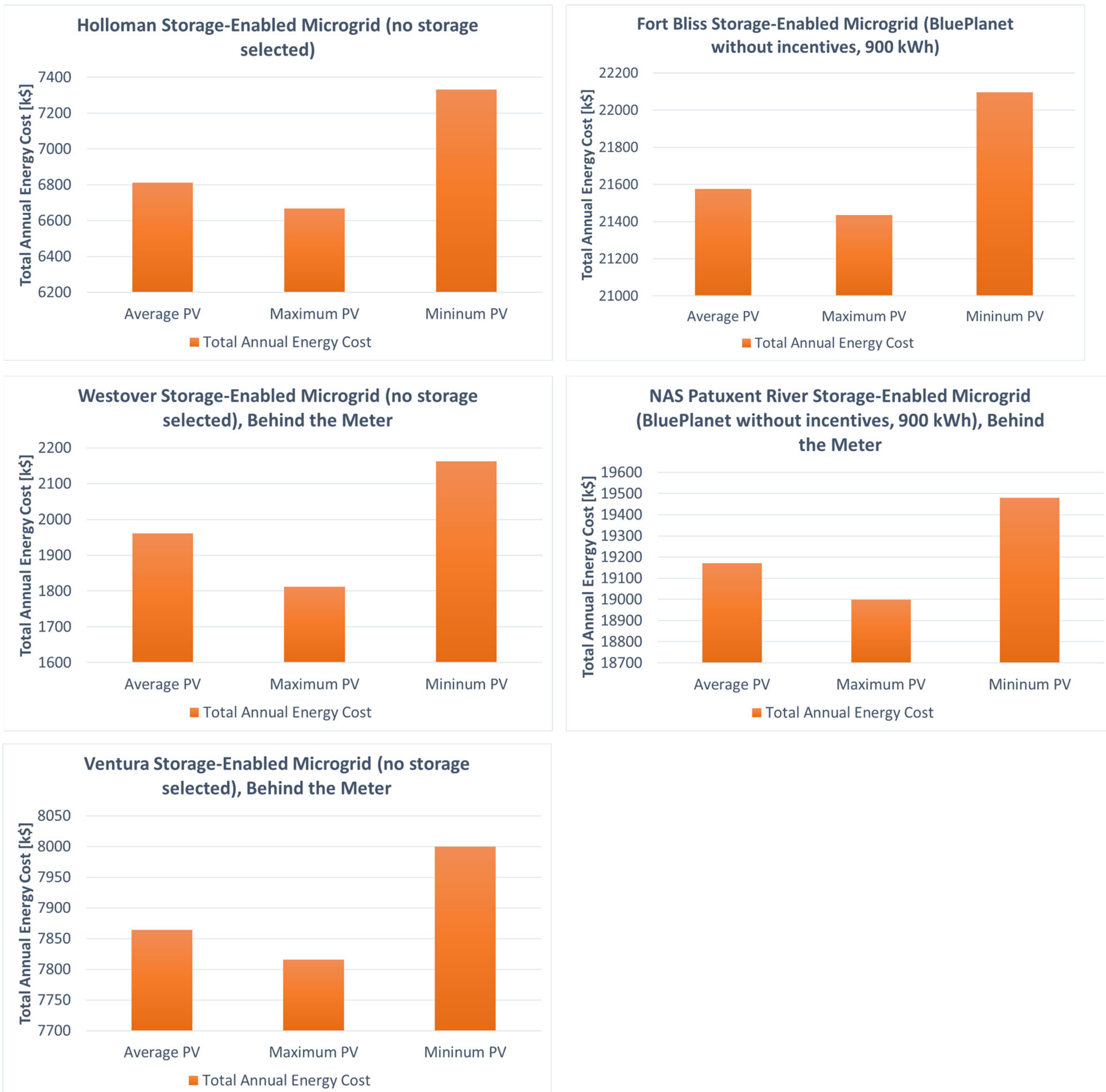


Figure 10. Impacts of PV Variability on Annual Energy Costs for Each Location Using an Optimized Storage-Enabled Microgrid with No Incentives and No Wholesale Market Participation.

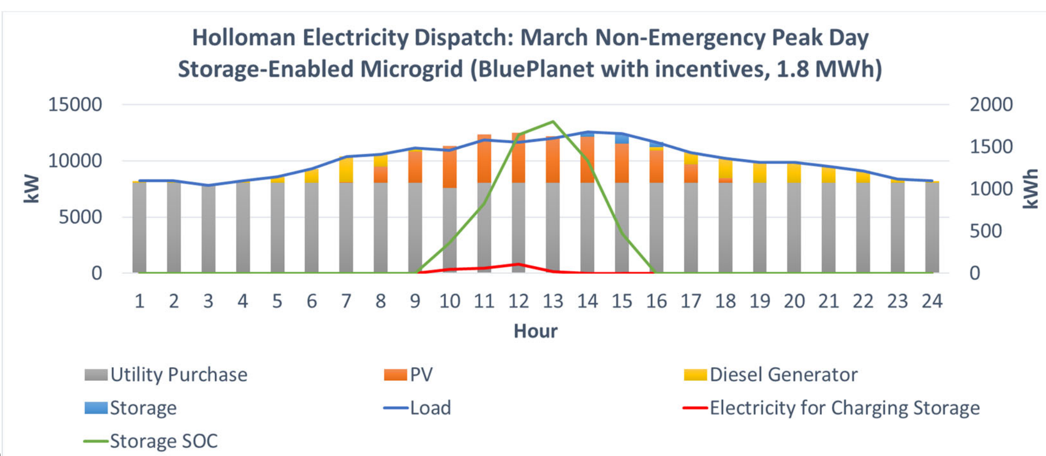
6.7 COST OPTIMAL OPERATION & DISPATCH UNDER GRID CONNECT CONDITIONS

Sample dispatch curves are included to shed light on storage sizing decisions, as well as illustrate how a storage-enabled microgrid with a smart controller can minimize operation costs. The dispatch curves chosen are from Storage Sizing for Economics results, showing the optimal technology portfolio in Behind the Meter (no wholesale market participation) cases with current ancillary service prices and average PV output. No incentives are included in the design and dispatch algorithm for Fort Bliss, as the model specified energy storage without incentives. However, to demonstrate energy storage dispatch, all other locations were modeled with incentives, since there is no energy storage selected when incentives are not applied.

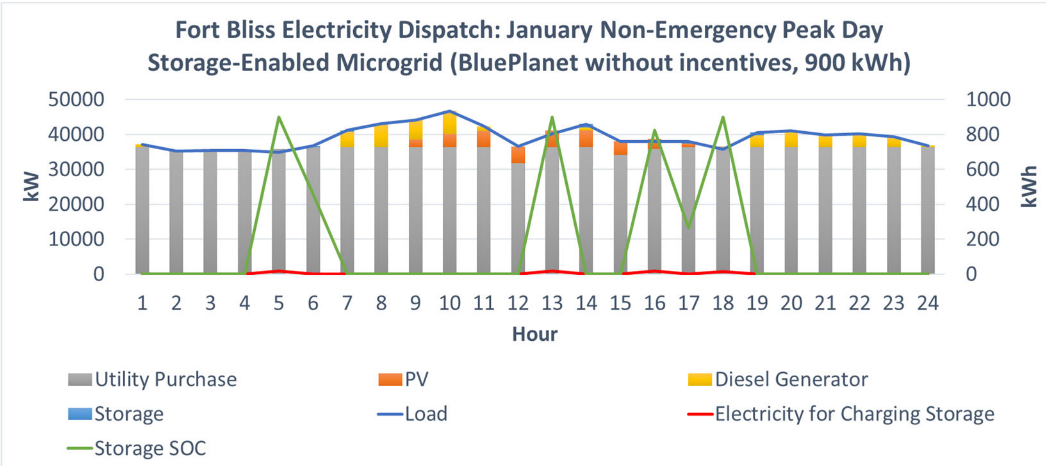
Therefore, cost-minimal operation is a balance between reducing energy and demand charges with additional capacity, and reducing annualized costs. Holloman and Westover both have large PV systems relative to the total load, and therefore the cost-beneficial decision is a larger storage system that, combined with PV and diesel generator dispatch, flatten the utility purchases and reduce both energy and demand charges.

For Fort Bliss, Ventura, and NAS Patuxent River, the PV capacity is much smaller relative to the load, and there is little opportunity for storage system charging and dispatch. However, potential to increase revenue through reserving storage capacity for ancillary services and demand charge reduction via peak shaving improves project financials.

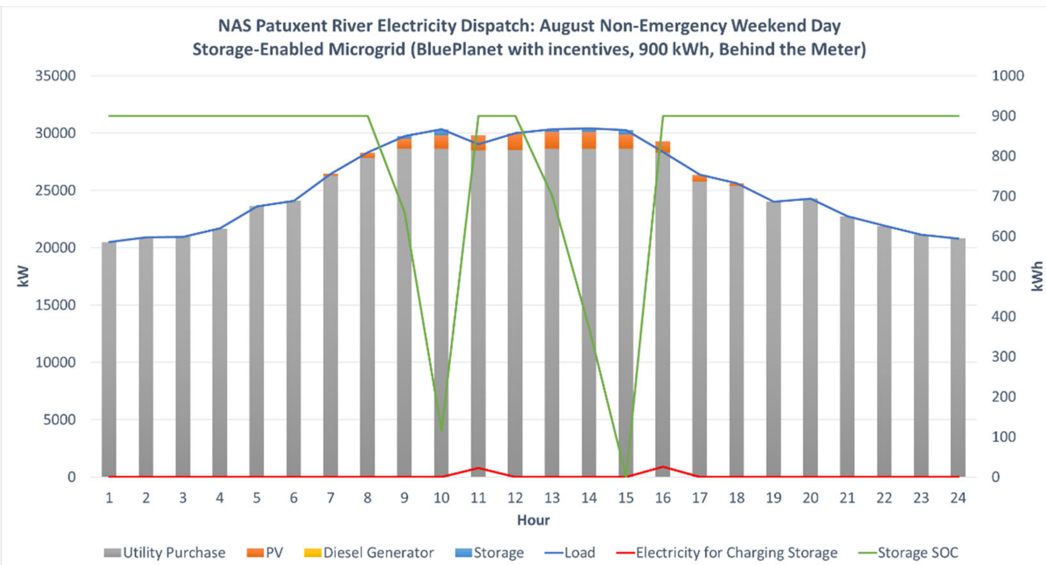
Figure 11 depicts several more unique observations. On installations with significant potential for AS revenue (C,D), the storage is encouraged to keep a higher SOC, despite the losses in energy due to the self-discharge. This result indicates that AS market participation and on-site reliability are correlated. The most significatn peak shaving occurs when the on-site generators are allowed to be used in peak shaving (A,B,E). Installaltions with a significant PV capacity to load ratio allow the storage to have the greatest impact on net load (A,E), while installations with small PV see practically no impact during non-outage conditions. Each installations ecnourages at least one complete charging cycle per day as part of its optimal operation. On installations (A,C,E) the net load is increased during parts of the day, to allow for recharging of the storage for either increased As participation, or some peak shaving later in the day.



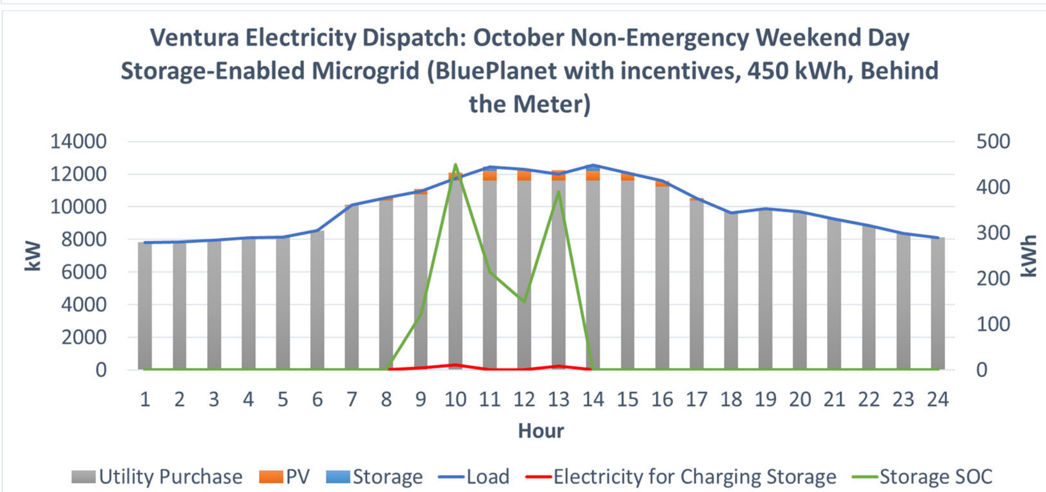
(A)


Fort Bliss Electricity Dispatch: January Non-Emergency Peak Day
Storage-Enabled Microgrid (BluePlanet without incentives, 900 kWh)
kW
kWh
Hour
Utility Purchase
PV
Diesel Generator
Storage
Load
Electricity for Charging Storage
Storage SOC

(B)


NAS Patuxent River Electricity Dispatch: August Non-Emergency Weekend Day
Storage-Enabled Microgrid (BluePlanet with incentives, 900 kWh, Behind the Meter)
kW
kWh
Hour
Utility Purchase
PV
Diesel Generator
Storage
Load
Electricity for Charging Storage
Storage SOC

(C)


Ventura Electricity Dispatch: October Non-Emergency Weekend Day
Storage-Enabled Microgrid (BluePlanet with incentives, 450 kWh, Behind the Meter)
kW
kWh
Hour
Utility Purchase
PV
Storage
Load
Electricity for Charging Storage
Storage SOC

(D)

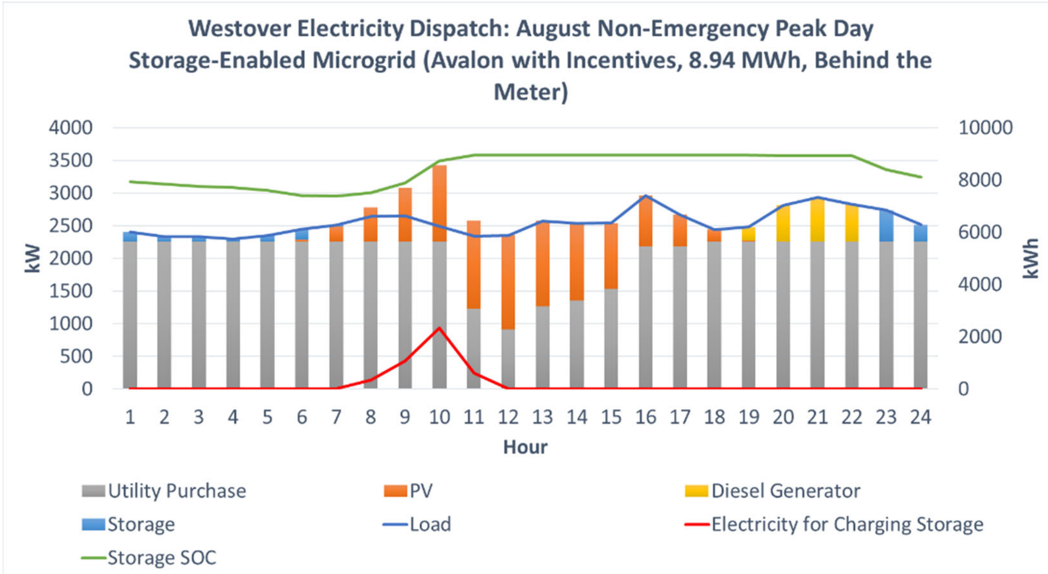
(E) 

Figure 11. Sample Dispatch Curves for Each Location Using Optimized Energy Storage Microgrid.

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7.0 COST ASSESSMENT

The purpose of this section is to identify the information that was used and the methods that were employed to establish realistic costs for implementing the energy storage enabled microgrid technology. For clarity, the summary of Net Protection Cost is repeated here and summarized to allow for direct comparison of NPC amongst scenarios evaluated (Table 23). Further discussion of the impacts of optimized energy storage enabled microgrids, market participation, incentives, and whole-asset optimization, including PV, are provided in the remainder of this section. Although much of the analysis is focused on impact on NPC, as summarized in Table 23, additional figures and discussions illustrate impacts on site economics via use of LCOE and annual energy costs.

Table 23. Summary of Net Protection Cost for All Locations and Scenarios With and Without Incentives and Baseline Microgrid.

Base	Scenario	Maximum Critical Load (kW)	Diesel Gensets	UPS	Microgrid	Energy Storage	Demand Response and Peak Shaving Savings	Ancillary Services and Wholesale Market Savings	Protecting each Kilowatt of Peak Critical Load
Holloman AFB	**Baseline**	5996	$49.38	$22.58	$36.39	$0.00	($10.00)	$0.00	$98.35
Holloman AFB	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	5996	$38.41	$22.58	$36.39	$0.00	($33.26)	$0.00	$64.12
Holloman AFB	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	5996	$32.92	$22.08	$36.39	$6.56	($38.55)	$0.00	$59.40
Fort Bliss	**Baseline**	12507	$47.10	$18.15	$17.44	$0.00	$0.00	$0.00	$82.70
Fort Bliss	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	12507	$35.33	$17.89	$17.44	$3.77	($43.26)	$0.00	$31.17
Fort Bliss	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	12507	$35.33	$17.89	$17.44	$4.71	($43.88)	$0.00	$31.49
NAS Patuxent River	**Baseline**	8014	$49.26	$22.09	$36.27	$0.00	($10.00)	$0.00	$97.63
NAS Patuxent River	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	8014	$36.95	$21.60	$36.27	$5.88	($33.62)	($0.71)	$66.37
NAS Patuxent River	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	8014	$36.95	$21.60	$36.27	$2.45	($32.16)	($0.99)	$64.12
NB Ventura Co.	**Baseline**	4003	$57.53	$23.42	$54.50	$0.00	$0.00	$0.00	$135.45
NB Ventura Co.	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	4003	$41.09	$23.42	$54.50	$0.00	($42.12)	$0.00	$76.89
NB Ventura Co.	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	4003	$41.09	$22.89	$54.50	$2.45	($45.01)	($0.54)	$75.38
Westover ARB	**Baseline**	1707	$77.09	$30.51	$85.34	$0.00	($27.00)	$0.00	$165.94
Westover ARB	**ESS-Enabled Microgrid; No Incentives; Current Pricing**	1707	$38.54	$30.51	$85.34	$0.00	($24.63)	$0.00	$129.77
Westover ARB	**ESS-Enabled Microgrid; ITC and MACRS Incentives; Current Pricing**	1707	$38.54	$29.83	$85.34	$99.38	($0.77)	($233.65)	$18.67

7.1 COST DETAILS

Technology installation costs and microgrid operation costs are key drivers in the sizing decision, therefore, NPC and LCOE trends are influenced by a combination of cost and performance parameters. The storage options vary not only in installation cost, but also in energy to power ratio, decay rates, efficiencies, lifetime, and O&M costs, all of which are factors in the annualized investment costs minimized when determining optimal storage capacity. Given this, it is unsurprising that NPC and LCOE trends do not correlate to storage power capacity alone.

A greater impact on system economics, including NPC and LCOE, is the market participation option. For the three military bases that provided data on RTP and ancillary service prices, participation in the wholesale market improves project financials compared to continuing with existing utility agreements and providing ancillary services behind the meter. The impact of market participation is illustrated in Figure 12 for Westover and Patuxent. Wholesale market participation at these locations has much more of an impact than addition of storage at these locations, accounting for over 90% of the reduction in annual electricity costs.

When comparing the baseline microgrid and the optimized microgrid, the NPC and LCOE are reduced, primarily as a result of reducing the number of required gensets, while still providing adequate critical load coverage, reducing annualized costs.

For Ft. Bliss, significant reductions in NPC can be provided by installing a small amount of energy storage and by improving dispatch algorithms to utilize storage as well as existing assets to improve behind the meter peak shaving operations and reduce demand charges.

When incentives are considered, and storage is specified at all installations, with the addition of storage to the PV and diesel generators, LCOE reduction of roughly 1% to 4% from the baseline microgrid and the optimized energy storage enabled microgrid without incentives.

Westover provides a unique case when incentives are considered. In this case, as a result of the large amount of PV installed relative to peak load, and access to wholesale markets and incentives, a large amount of energy storage is specified. This storage, in conjunction with PV is utilized to massively increase the market participation, resulting in a nearly 10x increase in revenues from ancillary services and wholesale market participation when compared to savings from behind the meter activities such as demand reduction via peak shaving.

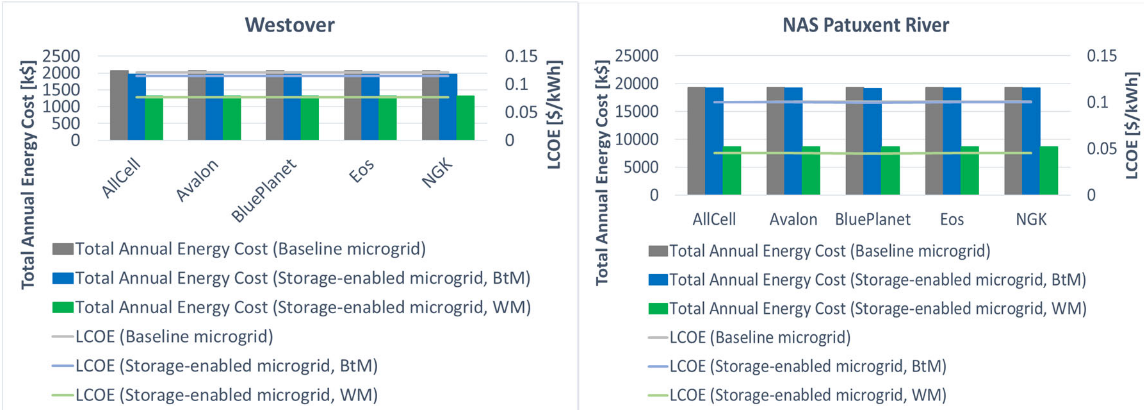


Figure 12. Total Annual Energy Cost Reduction Comparing Baseline Microgrid to Storage-enabled Microgrid – No Incentives – With and Without Wholesale Market Participation.

7.1.1 Impact to Installation Electricity Charges

A few common trends can be observed across all bases. Addition of storage provides some degree of demand charge reduction across each of the bases. Note, however, that for those installations with significant market participation potential (i.e. Westover), utilization of storage to enable market participation provides significantly more benefit than potential demand reduction, directing the dispatch algorithm to focus on market participation to the detriment of utility charge reduction.

For the optimized microgrid without incentives, since little or no energy storage is specified, there are negligible changes in annual energy costs associated with the implementation of the microgrid. In some cases, for certain technologies, the annual energy costs actually increase very slightly in the microgrid (Figure 13). The reasoning for the increase in annual utility energy charges is due primarily to the poor round trip efficiency, and large self-discharge losses. With these large losses, the microgrid must allot more solar PV to battery charging, which requires greater utility purchases to meet the load. Increased utility bills could also result from utilization of grid electricity for storage charging in certain scenarios. These technologies would not be selected for the optimized energy storage enabled microgrid unless other factors drove their selection (such as capital cost, operating cost, or lifetime benefits). ***It is worth noting, though, that despite the increases in energy charges, the storage devices still produce utility cost savings.***

Another cause of increase energy charges is the selection of fewer generators in combination with the selection of low storage capacity. As the generators may provide peak shaving, fixing the number of generator units to the number specified by ESTCP for the baseline modeling increases the overall costs, which is mitigated through frequent dispatch of generators to offset utility charges. When the DERs are sized for reliability and for economics, fewer generators are required to meet the modeled outage demand, resulting in an increase in utility charges compared to the baseline. This increase is only somewhat (or not at all) offset by a small storage selection, which, as noted above, is further constrained in dispatch abilities by the small PV capacity available. Charging from the utility (only permitted in scenarios when ITC or MACRS incentives are not modeled) or from the generators is energy inefficient, and therefore not a primary driver in the optimized storage operation and sizing.

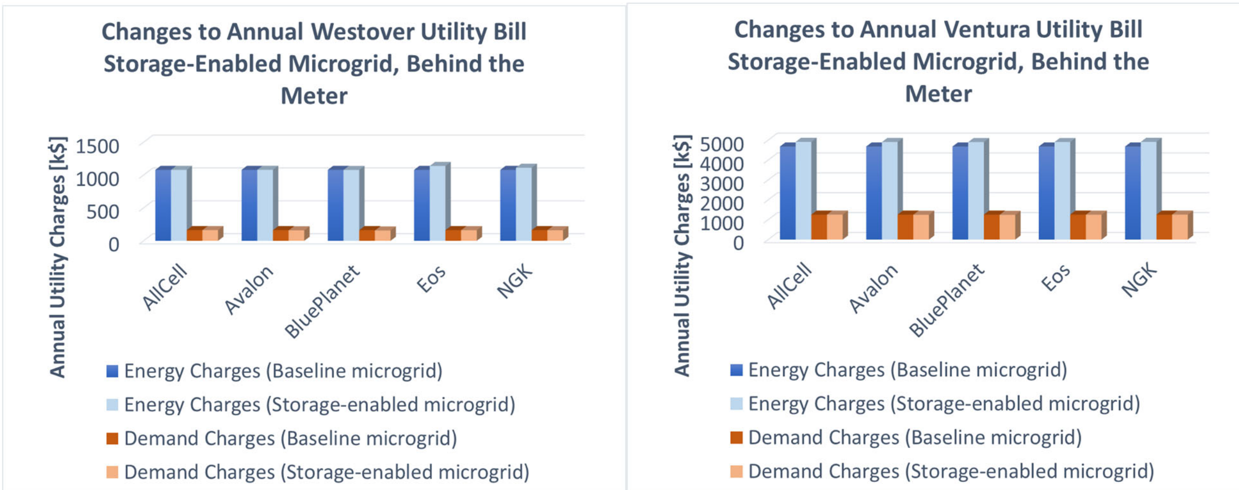


Figure 13. Example of Impact of Storage-enabled Microgrid on Annual Utility Bills, Illustrating Potential Increase in Utility Bills When Storage Is Included Due to Efficiency, Self-discharge, or Utilization of Grid for Charging.

7.1.2 Impact to Operation and Maintenance Costs

The O&M of each installation in the base case is due to the maintenance required to up-keep the backup generators and the UPS systems. In the optimized microgrid, for each location, the number of generators was reduced, with or without storage. As illustrated in Figure 14, this provides a reduced O&M cost associated with the reduction in gensets. This illustration is for Westover, but all locations show a similar impact under the optimized microgrid scenario with no incentives.

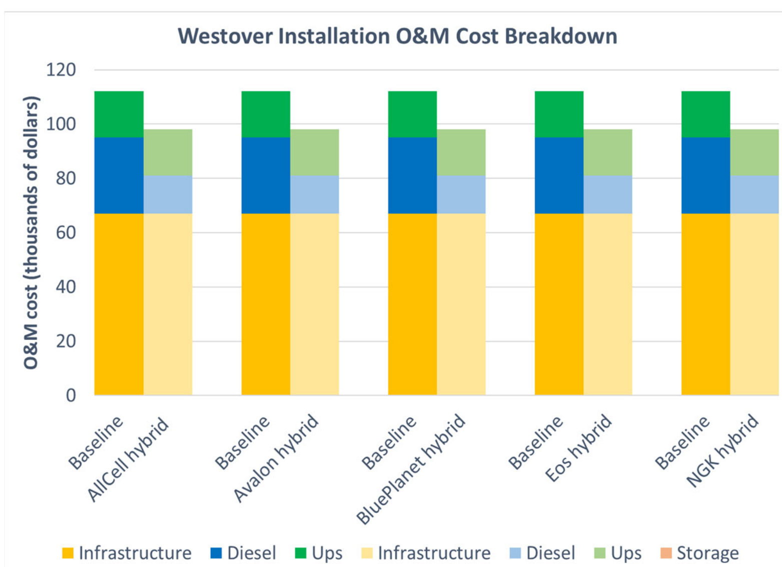
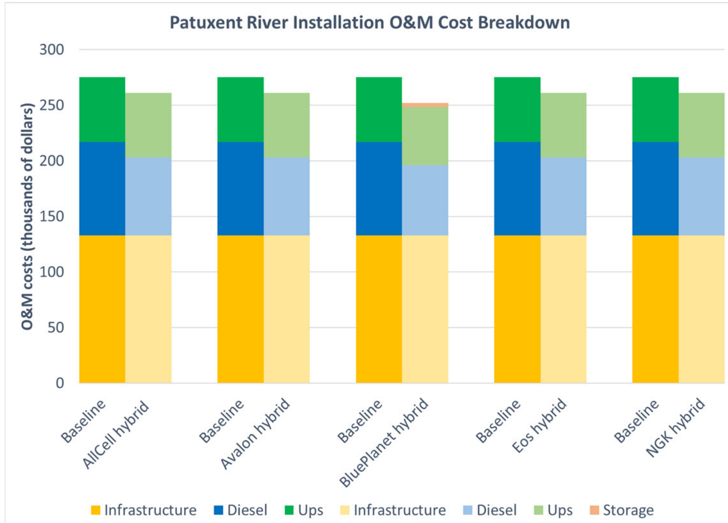


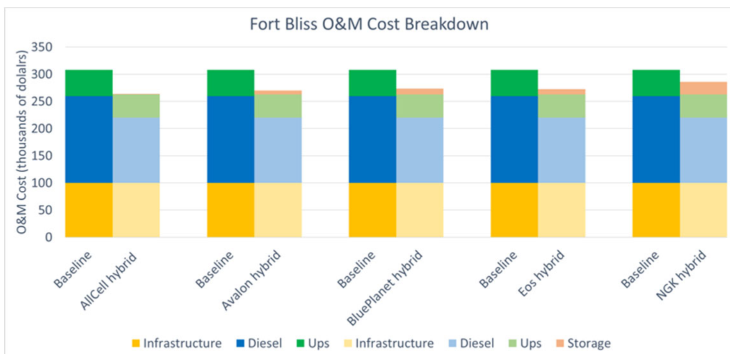
Figure 14. Modeled O&M Costs for Westover ARB for an Optimized Microgrid with No ITC or MACRS Incentives - Illustrating a Reduction in Genset O&M and No Addition of Energy Storage.

When considering hybrid-storage systems, the number of generators can also be reduced, potentially more, due to the storage providing backup power. Further, since the system is a hybrid, composed of storage and ultra-capacitors, the burden on the UPS system is lessened. For this work, we approximate a 10% annual savings in UPS system O&M costs. However, the O&M associated with the storage devices typically makes up for this reduction.

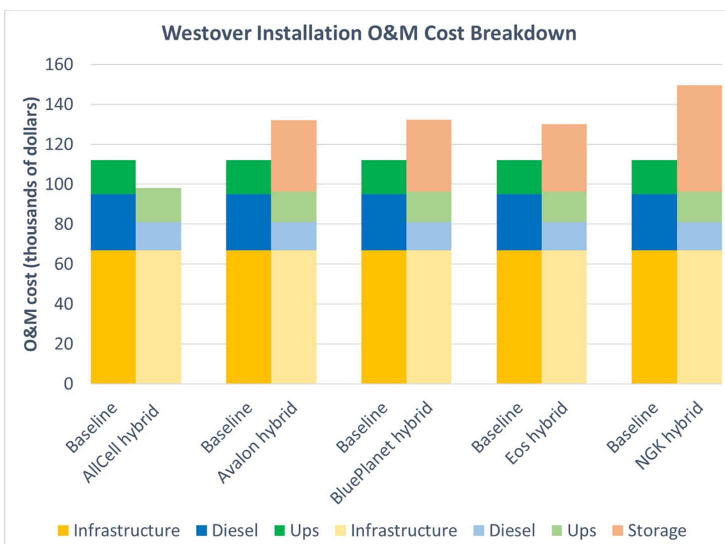
For all storage technologies and all bases, except Westover, similar trends are observed. O&M costs are reduced in the optimized microgrid, regardless of scenario – incentives, market participation, current or future volatile pricing, due to a reduction in diesel gensets at each location. At Westover, due to the potential for large storage installations modeled for four of the five technologies, significant additional costs for storage system O&M are included, resulting in overall increased O&M costs (Figure 15-C). However, the increase in O&M costs does not inhibit the economic performance at Westover or the NPC improvements (Table 23).



(A)



(B)



(C)

Figure 15. Impact of Storage-enabled Microgrid on Annual O&M Costs for Ft. Bliss (A) and Patuxent (B) with No Incentives – Illustrating Minimal Impact of Storage on O&M. Impact of Significant Quantity of Storage at Westover (C) When Incentives Are Included Demonstrates Potentially Significant O&M Costs of Storage, While Still Providing Improved Economics.

7.1.3 Ancillary Services as a Revenue Stream

Only three installations (NAS Patuxent River, Ventura, and Westover) considered ancillary services as a potential revenue stream. Of these three installations, ESTCP provided a "volatile" scenario for the wholesale participation model. However, only Westover provided a "volatile" scenario for the behind-the-meter case. These "volatile" scenarios provide insight into the relationship between project evaluation metrics (e.g. economics) and different wholesale market scenarios. Understanding these relationships enables a more informed investment decision to be made when evaluating microgrid portfolios.

Westover provided the greatest potential for AS revenue of all the bases, with NGK, EOS, and Avalon hybrid technologies providing the majority of the revenue. On each base, EOS generally provides the greatest AS potential, which is in-line with the fact that it also invests in the greatest capacity, thus having the most energy to reserve. We also observe the LCOE is directly correlated with AS revenue, where larger shares of AS revenue produce the solutions with the lowest overall LCOE. For the Wholesale Market cases, low RTP rates drive down storage sizing, which in turn drives down AS revenue.

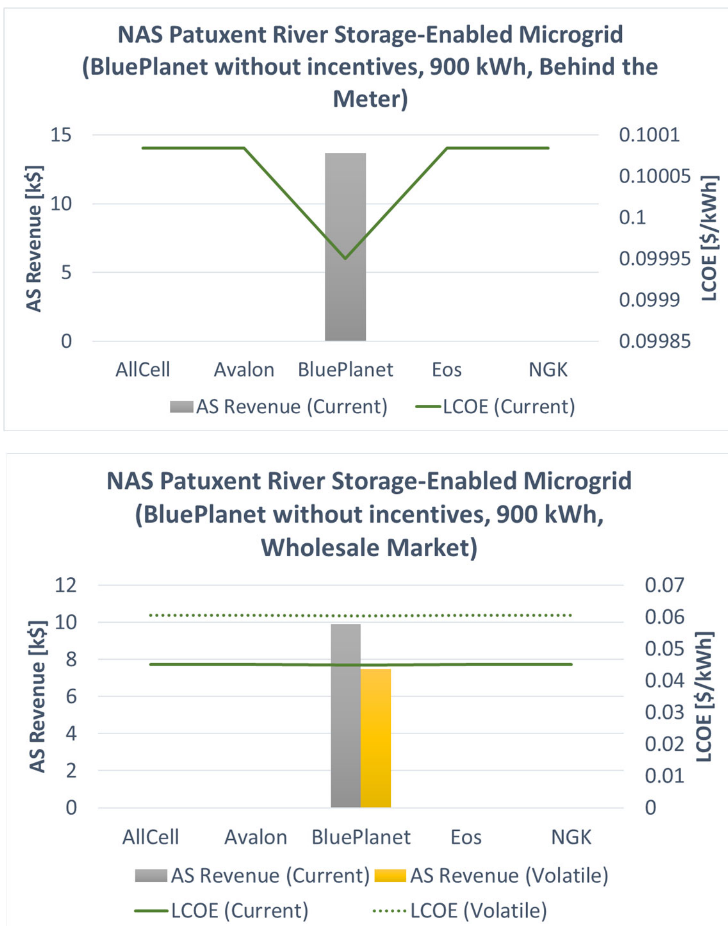


Figure 16. Potential Annual Revenues from Ancillary Services with Storage-enabled Microgrid with No ITC or MACRS Incentives.

Only NAS Patuxent River specified energy storage asset inclusion in the optimized microgrid.

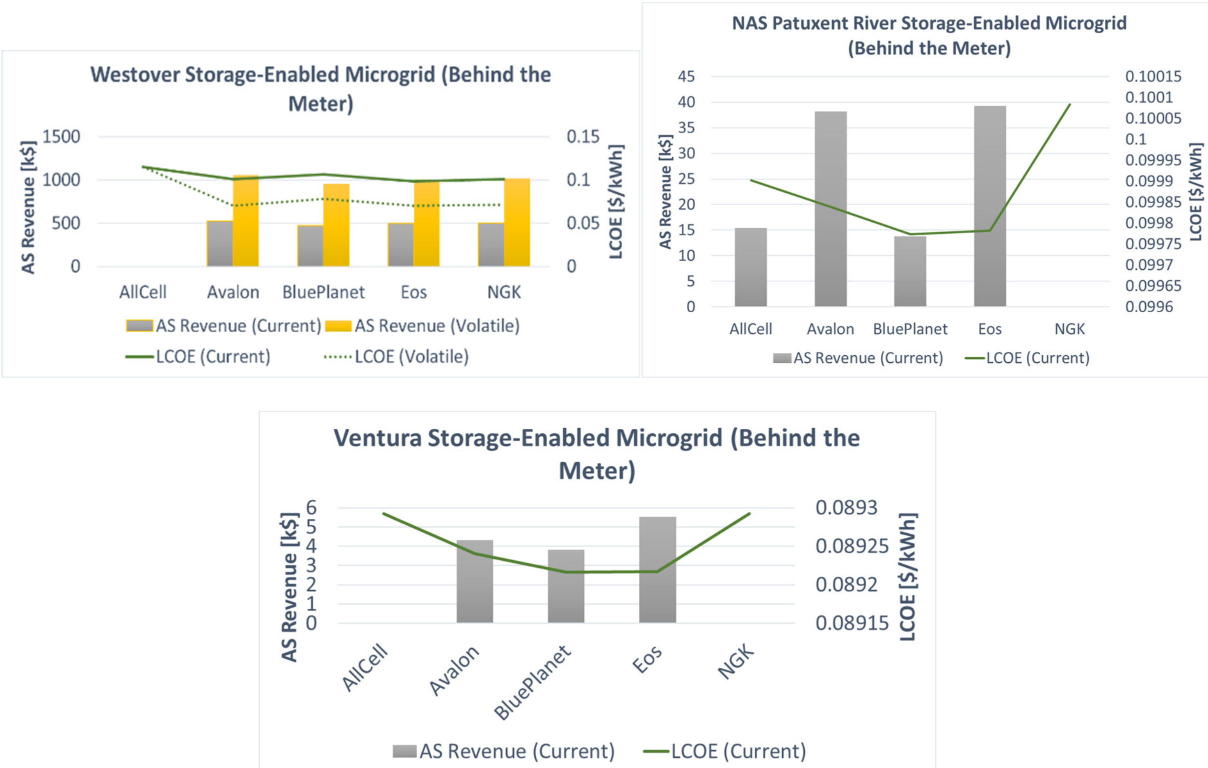


Figure 17. Potential Annual Revenues from Ancillary Services with Storage-enabled Microgrid – ITC and MACRS Incentives Applied.

7.2 COST DRIVERS AND COST OPTIMAL SIZING OF ALL ASSETS

PV system size relative to total load is a primary driver in storage sizing and operation. To assess the potential benefit of installing additional PV at a military base with a small ratio of PV array capacity to peak load, we repeated the Storage Sizing for Outages modeling for Ventura, this time allowing PV as well as storage and diesel generators to be sized by XENDEE. All technology capacities were sized to minimize total annual energy costs while meeting critical load during outages. PV installation costs were set at a $/kW value that captured the value of PV power production if assumed to be equal to utility purchases, as directed by ESTCP. The calculation of the installation costs are described in section 5.2.1.

The resulting optimal technology portfolio was used to repeat the storage sizing for economics modeling for Ventura. The sizing and financial results for both the planned PV (830) and the PV sized by XENDEE are shown for the Behind the Meter market participation case, assuming current ancillary service prices. Also shown is the LCOE calculated for a year of normal operation (without outages), with load met by a combination of DER generation and utility purchases.

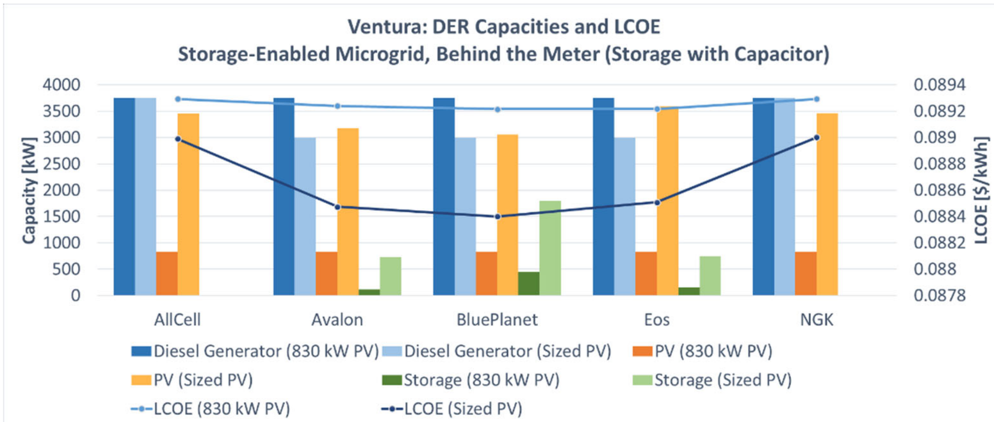


Figure 18. Optimal Sizing of All Assets (PV, Generators, Storage) for Ventura.

When all three technologies are optimally sized, rather than restricting the PV array capacity to the pre-planned 830 kW, the optimal technology portfolio includes a much greater amount of PV and storage. The increase in PV and storage capacity improves microgrid ability to meet critical loads through renewable generation and storage, and fewer diesel generators are needed for backup power.

7.2.1 Impact of Sizing All Assets on Performance

The critical load coverage probability dispatch analysis and five scenario simulations were performed using the optimal microgrid portfolio of Ventura when all energy assets were sized. The 168-hour outage scenarios in Table 24 and Figure 19 indicate:

- The Sized PV microgrid portfolio exceeds the generator only microgrid design when serving 100% critical load for a 7-day outage. The 830 kW PV microgrid portfolio produced a lower CLCP than the baseline microgrid but still meets the required CLCP.

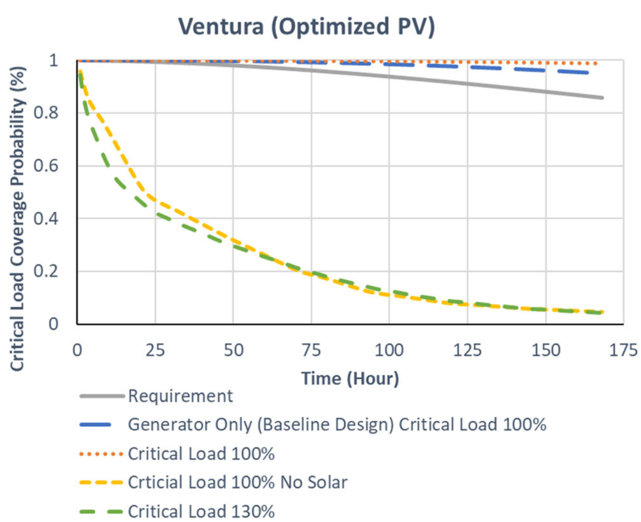


Figure 19. Annual average critical load coverage probability for a 168-hour grid outage event for facility with fully optimized microgrid assets, including increase in quantity of on-site PV from 830kW to 3593 kW.

- There is a significant fuel savings during the 100% critical load scenario using the Sized PV microgrid portfolio when compared to the baseline design and the 830 kW PV microgrid portfolio.
- The Sized PV microgrid portfolio is less likely to meet the critical load when no solar is available due to installing less generators and being more reliant on solar PV generation stored in the larger battery stack.
- There is similar behavior for both the 830 kW PV and Sized PV microgrid portfolios when serving a 130% critical load due to the sizing of the total generation assets being optimal for a 100% load profile.

Table 24. Summary of Fuel Consumption and Proportion of Critical Load Served for 168-hour Outages.

Base	Generator Only Average Fuel Consumption (gal)	Critical Load 100% Average Fuel Consumption (gal)	Critical Load 100% No Solar Average Fuel Consumption (gal)	Critical Load 130% Average Fuel Consumption (gal)	Critical Load 130% Average Proportion of Critical Load Served (%)
Naval Base Ventura Co.	38,299	27,654	37,758	37,932	98.0

The 24-hour outage scenarios summarized in Table 25 indicate that the Sized PV microgrid portfolio outperforms the 830 kW PV microgrid portfolio when meeting a 30% and 10% critical load profile with no fuel due to having sufficient battery capacity to serve the load until the larger solar PV array can begin to generation power to serve the load and recharge the battery stack. The Sized PV microgrid portfolio also significantly exceeds the average proportion of the critical load served for these scenarios when compared to the 830 kW PV microgrid portfolio. However, the Sized PV microgrid portfolio produces a lower CLCP curve and serves a lower average proportion of the critical load when serving a 130% critical load profile due to being more reliant on variable generation sources.

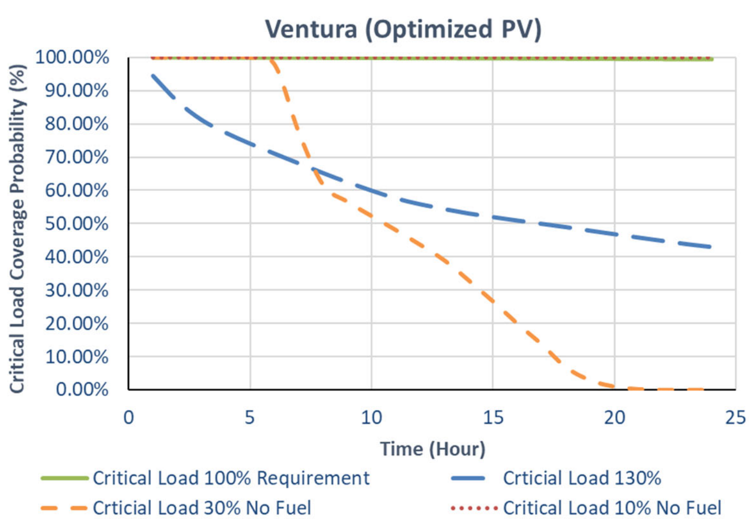


Figure 20. Annual Average Critical Load Coverage Probability for a 24-hour Grid Outage Event

Table 25. Annual Average Critical Load Coverage Probability for a 24-hour Grid Outage Event.

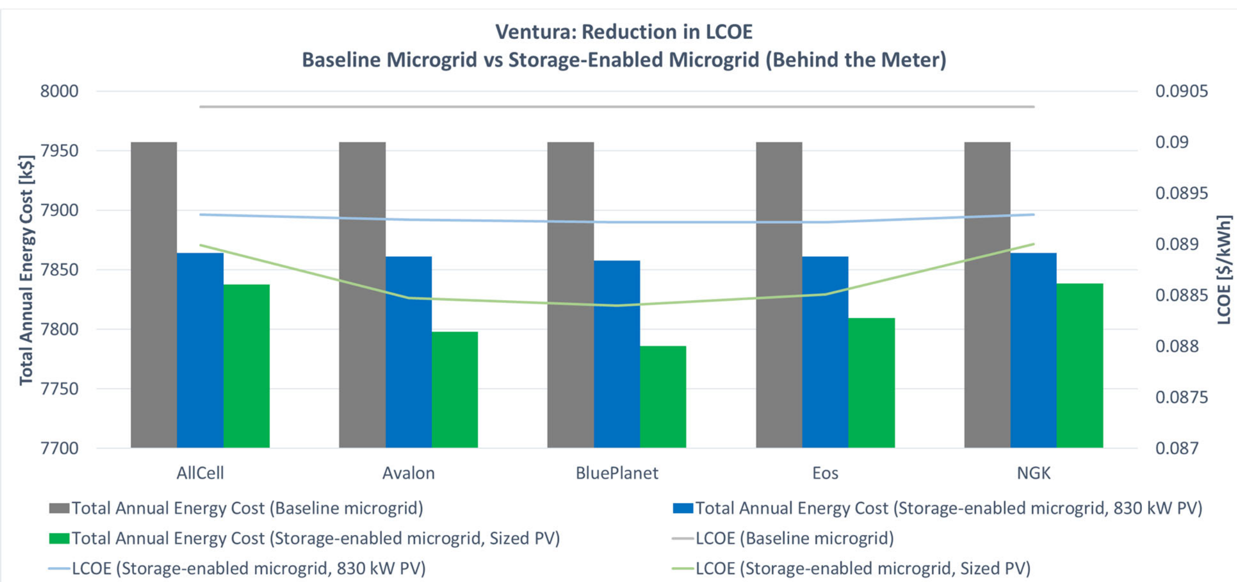
Base	Critical Load 130 Average Fuel Consumption (gal)	Critical Load 130% Average Proportion of Critical Load Served (%)	Critical Load 30% No Diesel Fuel Average Proportion of Critical Load Served (%)	Critical Load 10% No Diesel Fuel Average Proportion of Critical Load Served (%)
Naval Base Ventura Co.	5,435	98.2	72.8	100.0

7.2.2 Impact of Sizing All Assets on Economics

A significant reduction in both LCOE and total annual energy cost can be achieved with additional PV and storage, with more opportunities for demand charge reduction and price arbitrage during normal operation. Both utility energy purchases and demand charges are significantly reduced when the microgrid is sized without the 830kW array capacity restriction. Total annual energy cost is a year-one value and includes all O&M and annualized capital expenses from distributed energy resources.

Total technology O&M costs for Avalon and Eos increase, primarily from the additional investment in storage and PV. The increase in technology O&M costs is offset by the value provided through energy and demand charge reduction, as well as greatly increased revenue from ancillary services.

Additional PV capacity should be considered as an option to improve project financials. Roughly 0.1 square kilometer is required to accommodate the cost-optimal PV array capacity, compared to roughly 5,600 square meters for 830 kW PV. Therefore, space limitations will need to be taken into consideration.



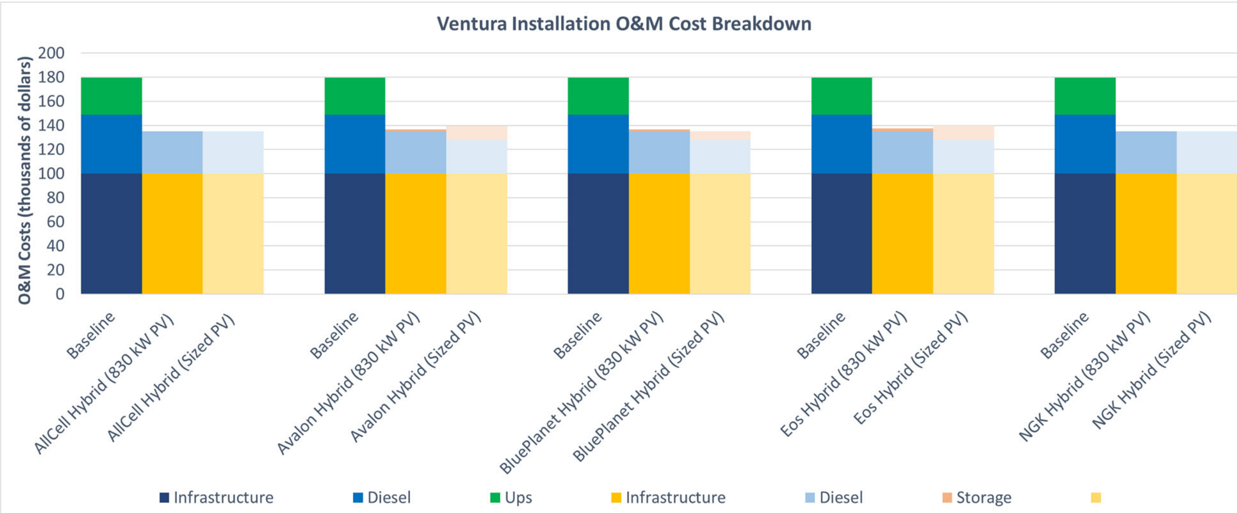


Figure 21. Impacts of Optimal Sizing of All Assets on LCOE and O&M Costs.

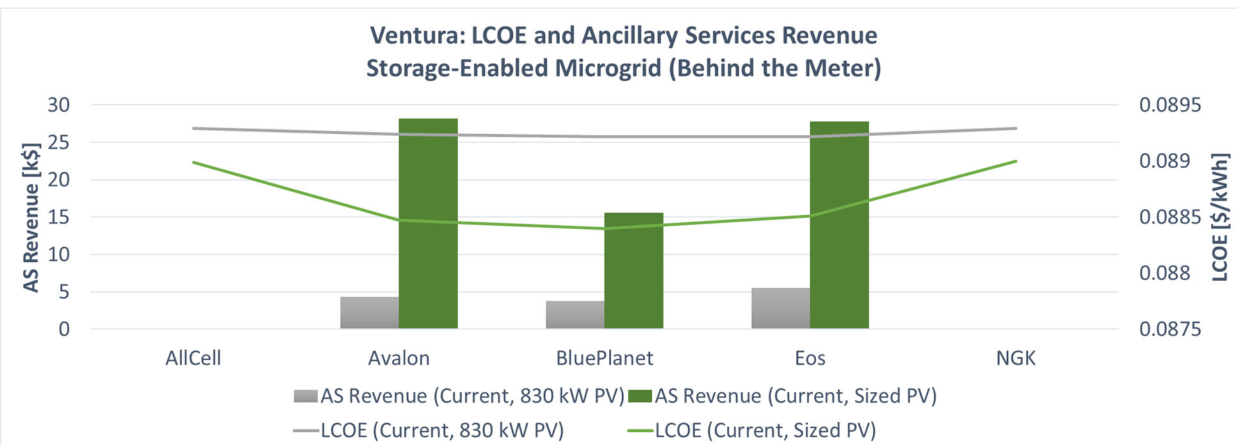


Figure 22. Potential Revenues for Ancillary Services with Optimized Asset Portfolio.

Table 26. Physical space required for optimized PV assets at Ventura.

Storage Technology	Capacity [kW]	Space [square meters]
AllCell	3450	23000
Avalon	3180	21200
BluePlanet	3059	20393
Eos	3593	23953
NGK	3458	23053

8.0 STUDY CONCLUSIONS AND OUTCOMES

The below findings demonstrate how the effort led by Southern Research using the ASU-XENDEE HESS microgrid modeling approach provide generalized findings and site-specific findings for the set of five DoD installation microgrids identified by ESTCP. Additional interpretations and suggested topics for future research are also discussed.

Topic	Finding
Asset selection and sizing	• Demonstrated financial benefits of improving the lifetime of long-duration storage by 20% using ultracapacitors modeled after secondary data from manufacturer and published studies (a conservative estimate from the range of 10% to 80% that can be quantitatively assessed in Phase II). The financial benefit of ultracaps was observed for installations that installed more storage and actively used storage, such as Westover which reduced generator count from 4 units to 2 units when including storage for on-grid economic dispatch and islanded security dispatch. • Demonstrated that permitting solar PV array size to be a design variable, rather than a fixed constraint, improved the financial and technical performance metrics of storage-enabled microgrids. The increase in solar PV led to an increase in storage capacity for the cost-optimal solution and reduced annual energy costs by up to 13% and improved survivability by up to 6% for a 7-day outage. Additional generators could also be removed with the increased provision of solar PV and storage. • BluePlanet showed the most consistent financial benefit for installations to reduce cost and increase ancillary service revenue across all cases: with and without incentives, behind and in front of the meter, and all installations. The slightly higher cost of BluePlanet, relative to other technologies evaluated, was offset by the benefit of a long-duration battery with 22-year lifetime, 99% efficiency, and low self-discharge rate. Storage from Avalon and Eos were a second-tier, nearly equal solution and provided lower costs in certain cases for Westover. • Relaxing assumptions on generator behavior (non-constant heat rate, minimum loading) are expected to influence performance and financial calculations. The effect of such changes are recommended for quantitative evaluation in Phase II.
Performance	• The Energy Security Model (ESM) developed in this work improved reliability an average of 0.3% and 8.4% over 24-hour and 168-hour time horizons, respectively, as measured by the critical load coverage probability curve (CLCPC) for optimal microgrid with ITC and MACRS incentives considered. • Hybrid storage-enabled microgrids could exceed critical load requirements and serve 127 - 130% of the critical load for a 168-hour outage. • The variability of solar PV had a significant effect on microgrid survivability, with three of the five storage-enabled microgrids not meeting CLCPC requirements when solar PV generation was unavailable. This suggests further study of solar PV uncertainty be added to Phase II to assess how solar PV edge cases (clear sky and no sun) and the probabilities in between will affect survivability. Further, a control feedback loop could be added to allow a human-machine team to make decisions on if curtailing load could allow the microgrid to survive days with minimal to no sun. • Quantified the reduction in survivability for scenarios with no fuel, and identified bases with increased solar and storage (Westover ARB, Holloman AFB) had greater survivability. Such findings can be used to create manual or automated load control to maintain a minimum desirable CLCPC during time periods with mission needs and critical loads that change in real-time and fuel availability that may be extinguished or replenished. • The cost-optimal solar PV and battery sizes permitted 56.8% and 86.1% of the 30%-critical load to be served over 24-hours in the no-fuel scenario for NAS Patuxent River and Westover ARB. This indicates that allowing more solar PV to be installed improves survivability. This scenario permitted ITC to be applied to storage when noting that additional solar PV would be installed in a new contract. • Reduced fuel use by 8.1 - 33.5% during 7-day outages at all bases, thereby increasing mission autonomy in case of fuel supply shortage. Holloman AFB and Fort Bliss showed greatest reductions in fuel use by using more storage to meet additional capacity requirements for CLCP that permitted generators to be turned off (or idle with no fuel use).

Topic	Finding
Financial	• A verification step was completed of XENDEE financial modeling to the actual recorded data with the modest 3.5% average discrepancy resulting from use of design days and assumptions made in consultation with ESTCP on how to reflect electricity bill components in an optimization framework. • Excluding ITC and MARCS incentives greatly decreased the financial efficacy of storage. For the behind-the-meter scenario, only two of the five installations would a modest amount of batteries, with Fort Bliss installing 900-2400 kWh across four battery vendors and Patuxent River installing 900 kW of BluePlanet batteries. When moving to a wholesale market the value of batteries dropped and only Patuxent River maintained energy storage. Minor changes in LCOE were observed. • Net Protection Costs can be reduced at all locations by optimizing the microgrid for economics. This is primarily achieved via reduction in number of diesel generators, which reduces probability of critical load coverage while still meeting requirements. • When evaluating scenarios where significant energy storage is deployed, such as including ITC/MACRS incentives and wholesale market participation, Net Protection Cost (NPC) can be further reduced. The most significant reductions in NPC occur at Westover, where significant quantities of PV match with large quantities of energy storage, enabling significant participation in the wholesale market. This results in a drastic reduction in NPC, from \$166/kW to \$19/kW, due almost entirely to revenues from wholesale market and ancillary services participation of over \$230/kW. • If including ITC and MARCS incentives, each installation can benefit financially from adding energy storage. The cost-optimal storage technology varied by base with respect to dispatch characteristics at the installation. BluePlanet was the cost-optimal solution for Holloman and Fort Bliss. Similar LCOE was observed for Avalon, EOS, and NGK at Westover, with any battery system providing similar annualized costs at Patuxent River and Ventura. • These financial results identify the optimal storage technology is case-specific, a finding that underscores the importance of the controls solution being vendor agnostic and adaptable to various storage technologies. Further, given the sensitivity of the optimized result depends on battery financial data, this optimization must be re-run for projects under planning given that battery costs are declining (25% by 2020 for one vendor) and international tariffs could negatively affect other vendors (10% increase for one vendor). • Demonstrated that front-of-the-meter microgrids could reduce annual energy costs by 33 - 55% relative to behind-the-meter microgrids by participating in the wholesale energy market. This structure would be more easily available if the microgrid is wholly owned or jointly owned by the local utility or grid operator with access to energy markets. Further, such ownership by a third-party would reduce capital and O&M costs to the installation. • Integrated on-grid economic optimization with off-grid reliability to provide resilience with an ROI that yielded payback periods of as low as 3 years for in-front-of-the-meter microgrids. ▪ Microgrid economics were improved by obtaining ancillary services revenues using BluePlanet technology for the Patuxent River case and no incentives. If including incentives, Patuxent River, Ventura, and Westover could gain ancillary services revenue using Avalon, BluePlanet, or Eos technology, with Avalon or Eos bringing the most revenue for two installations and the third installation receiving negligible change in revenue across vendors. • Modest differences in diesel fuel prices affected microgrid cash flow but do not affect the selection of assets and system sizing.

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APPENDIX A1. ENERGY STORAGE TECHNOLOGY CHARACTERISTICS

Table A-1. Energy Storage Technology Specifications

Characteristic (system block)	Maxwell Technologies	AllCell	EOS	NGK	Blue Planet	Avalon
Technology	Ultracapacitor	Li-ion	Aqueous Zn	NaS	LiFePO4	Flow
Capacity (power), kW	1300	480	150	200	450	7.5
Maximum energy, kWh	165	320	600	1,200	450	30
Round trip efficiency, %	85-95	90	75	75	98	80
Discharge rate, c-rate	BoP Limited	3C/2	C/4	C/6	1C	C/4
Response time and ramp rate, ms	< 1	TBD	< 5	100		
Self-discharge rate/ stdby energy loss, %.day	15	<1	0.67	<12	1% / mo	1% / hr
Expected calendar life, yrs	15	5	15-20	15	21	25
Expected Cycle Life	1,000,000	2,200	5,500	>4,500	8,000	20,000
Avg. Installed Footprint, ft2/block	7 (w/o BOP)	32 (w/o BOP)	159	200 kW / 381 800 kW / 696		
Avg. Installed Footprint per MWh, ft2/MWh	42.4	98.4	318	200 kW / 317 800 kW / 145		
Reliability	10-15 years with minimal O&M costs; anticipate 20y life within 5y.	Availability >99%. (4 down days per year)	Availability of 98%	Availability > 98%. Anticipate lifetime improvement 20y within 5y.	99% uptime	
Capital costs in $ per kWh of storage capacity, current and projected out 5 years (not including BOS)	$150/kW anticipate $100/kW in 5 years	$350/kWh to $280/kWh in 5 years	$240/kWh to $180/kWh in 5 years	Current: $317.66/kWh 5 years: $180.55/kWh	Current = $650/kWh +1 Year = $600/kWh; future years TBD	$563/kWh @ 250kW or less, $398 kWh @ 5MW or less
Fixed O&M costs in $ per kWh of storage capacity per year		$1-$10/kWh/y for 100kW to 1MW.	1 MW: $4/kWh/y; >20 MW: $2.75/kWh/y	$6.34/kWh/y	$4/kWh/y	$4/kWh/y
The self-discharge rate / standby energy loss discussion if applicable	15% / day	Self-discharge is of the order of 1% / mo.	1%/hr @ 100% SOC	No self-discharge. Heater use is 6kW for 200kW/1200kWh (20 ft container)	Discharge rate <1% per month	

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APPENDIX A2. INTEGRATED MODELING APPROACH

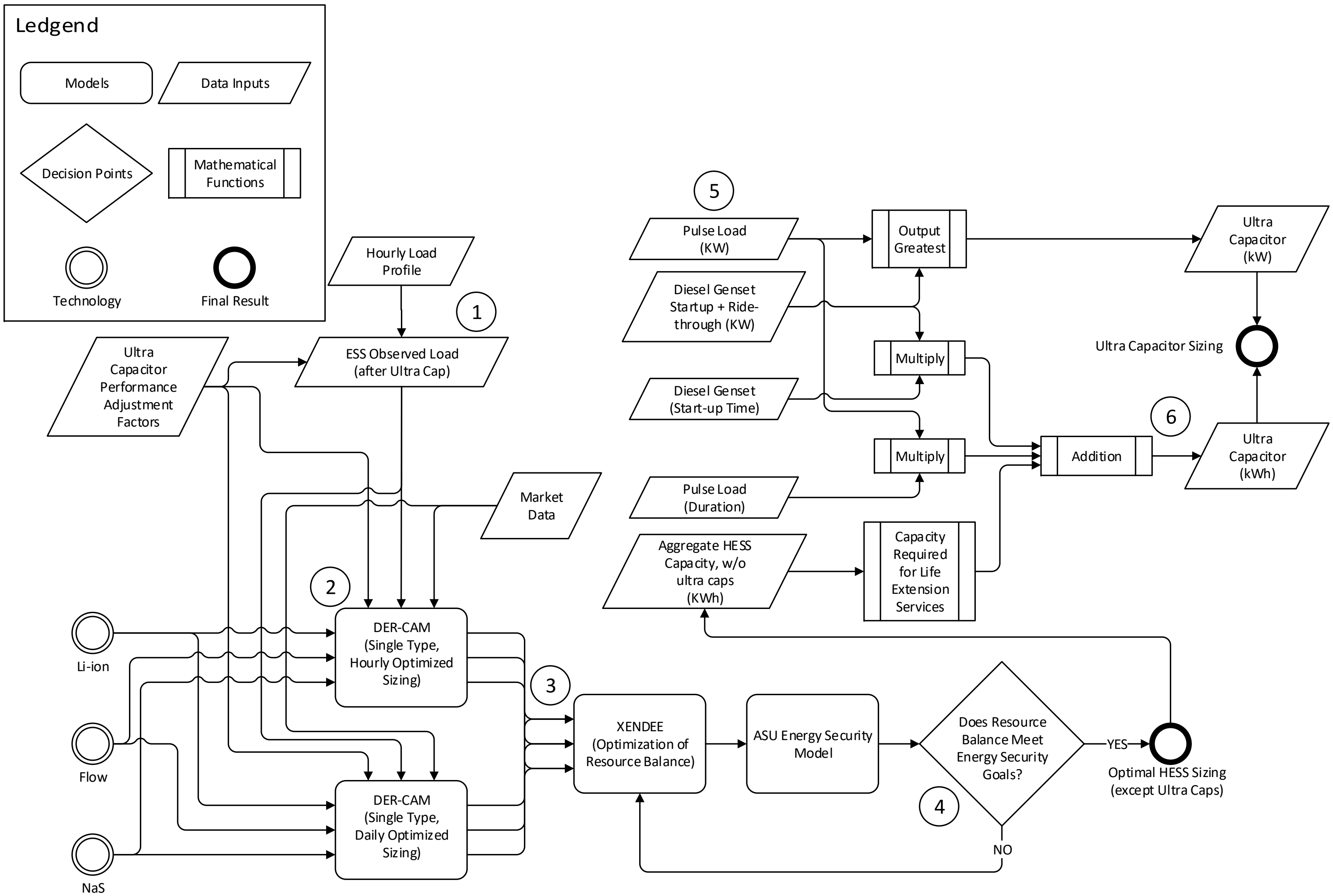

Figure A-1. SR-ASU-XENDEE Microgrid Modeling, Design, and Controls Optimization Process

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APPENDIX A3. OPTIMIZED MICROGRID DESIGN AND COST RESULTS

Highlight indicates lowest cost selection used for energy security modeling

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacity [kW]	Storage [number of units]	Total Storage Capacity [kWh]
Fort Bliss	**Microgrid O&M Costs [k$]**					
no ITC/MACRS	**100**					
FortBliss_Scenario2c_Current_AvgMonthlyPV_AllCellNoInc100	0.065763867	6	12000	6200	3	960
FortBliss_Scenario2c_Current_AvgMonthlyPV_AllCellNoInc120	0.065682763	6	12000	6200	3	960
FortBliss_Scenario2c_Current_AvgMonthlyPV_AvalonNoInc100	0.065699228	6	12000	6200	60	1800
FortBliss_Scenario2c_Current_AvgMonthlyPV_AvalonNoInc120	0.065658193	6	12000	6200	60	1800
FortBliss_Scenario2c_Current_AvgMonthlyPV_BluePlanetNoInc100	0.065529745	6	12000	6200	2	900
FortBliss_Scenario2c_Current_AvgMonthlyPV_BluePlanetNoInc120	0.065496961	6	12000	6200	2	900
FortBliss_Scenario2c_Current_AvgMonthlyPV_EosNoInc100	0.065729275	6	12000	6200	4	2400
FortBliss_Scenario2c_Current_AvgMonthlyPV_EosNoInc120	0.065671261	6	12000	6200	4	2400
FortBliss_Scenario2c_Current_AvgMonthlyPV_NGKNoInc100	0.06576399	7	14000	6200	0	0
FortBliss_Scenario2c_Current_AvgMonthlyPV_NGKNoInc120	0.06576399	7	14000	6200	0	0
Fort Bliss						
with ITC/MACRS						
FortBliss_Scenario2c_Current_AvgMonthlyPV_AllCellInc100	0.065486576	6	12000	6200	3	960
FortBliss_Scenario2c_Current_AvgMonthlyPV_AllCellInc120	0.065443615	6	12000	6200	3	960
FortBliss_Scenario2c_Current_AvgMonthlyPV_AvalonInc100	0.065496176	6	12000	6200	60	1800
FortBliss_Scenario2c_Current_AvgMonthlyPV_AvalonInc120	0.06547046	6	12000	6200	60	1800
FortBliss_Scenario2c_Current_AvgMonthlyPV_BluePlanetInc100	0.06551207	6	12000	6200	5	2250
FortBliss_Scenario2c_Current_AvgMonthlyPV_BluePlanetInc120	0.065518498	6	12000	6200	6	2700
FortBliss_Scenario2c_Current_AvgMonthlyPV_EosInc100	0.065475869	6	12000	6200	4	2400
FortBliss_Scenario2c_Current_AvgMonthlyPV_EosInc120	0.06544285	6	12000	6200	4	2400
FortBliss_Scenario2c_Current_AvgMonthlyPV_NGKInc100	0.065638795	6	12000	6200	3	3600
FortBliss_Scenario2c_Current_AvgMonthlyPV_NGKInc120	0.065592566	6	12000	6200	3	3600
Holloman	**Microgrid O&M Costs [k$]**					
no ITC/MACRS	**100**					
Holloman_Scenario2c_Current_AvgMonthlyPV_AllCellNoInc100	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_AllCellNoInc120	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_AvalonNoInc100	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_AvalonNoInc120	0.084639481	7	5250	5000	0	0

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacity [kW]	Storage [number of units]	Total Storage Capacity [kWh]
Holloman_Scenario2c_Current_AvgMonthlyPV_BluePlanetNoInc100	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_BluePlanetNoInc120	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_EosNoInc100	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_EosNoInc120	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_NGKNoInc100	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_NGKNoInc120	0.084639481	7	5250	5000	0	0
Holloman						
with ITC/MACRS						
Holloman_Scenario2c_Current_AvgMonthlyPV_AllCellInc100	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_AllCellInc120	0.084573793	6	4500	5000	5	1600
Holloman_Scenario2c_Current_AvgMonthlyPV_AvalonInc100	0.0845213	6	4500	5000	104	3120
Holloman_Scenario2c_Current_AvgMonthlyPV_AvalonInc120	0.084382007	6	4500	5000	104	3120
Holloman_Scenario2c_Current_AvgMonthlyPV_BluePlanetInc100	0.084259943	6	4500	5000	4	1800
Holloman_Scenario2c_Current_AvgMonthlyPV_BluePlanetInc120	0.084137384	6	4500	5000	4	1800
Holloman_Scenario2c_Current_AvgMonthlyPV_EosInc100	0.084451993	6	4500	5000	6	3600
Holloman_Scenario2c_Current_AvgMonthlyPV_EosInc120	0.084278151	6	4500	5000	6	3600
Holloman_Scenario2c_Current_AvgMonthlyPV_NGKInc100	0.084639481	7	5250	5000	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_NGKInc120	0.084639481	7	5250	5000	0	0
Patuxent	**Microgrid O&M Costs [k$]**					
no ITC/MACRS	**133**					
Behind the Meter						
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc100	0.100084067	10	7500	2000	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc120	0.100084067	10	7500	2000	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc100	0.100084067	10	7500	2000	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc120	0.100084067	10	7500	2000	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc100	0.100013355	9	6750	2000	2	900
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc120	0.099950221	9	6750	2000	2	900
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc100	0.100084067	10	7500	2000	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc120	0.100084067	10	7500	2000	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc100	0.100084067	10	7500	2000	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc120	0.100084067	10	7500	2000	0	0
Patuxent						
with ITC/MACRS						
Behind the Meter						
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc100	0.099983619	9	6750	2000	3	960
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc120	0.099902534	9	6750	2000	3	960

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacity [kW]	Storage [number of units]	Total Storage Capacity [kWh]
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc100	0.099894381	9	6750	2000	73	2190
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc120	0.099839279	9	6750	2000	73	2190
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc100	0.099817397	9	6750	2000	2	900
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc120	0.099772985	9	6750	2000	2	900
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc100	0.099845585	9	6750	2000	4	2400
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc120	0.099782083	9	6750	2000	4	2400
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc100	0.100084067	10	7500	2000	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc120	0.100084067	10	7500	2000	0	0
Patuxent						
no ITC/MACRS						
Wholesale Market (Current)						
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc100	0.045158049	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc120	0.045158049	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc100	0.045158049	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc120	0.045158049	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc100	0.0451051	9	6750	2000	2	900
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc120	0.045041968	9	6750	2000	2	900
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc100	0.045158049	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc120	0.045158049	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc100	0.045158049	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc120	0.045158049	10	7500	2000	0	0
Patuxent						
with ITC/MACRS						
Wholesale Market (Current)						
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc100	0.045103347	9	6750	2000	3	960
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc120	0.04502227	9	6750	2000	3	960
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc100	0.045021074	9	6750	2000	73	2190
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc120	0.044965979	9	6750	2000	73	2190
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc100	0.044936232	9	6750	2000	2	900
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc120	0.044891817	9	6750	2000	2	900
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc100	0.044965116	9	6750	2000	4	2400
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc120	0.044901622	9	6750	2000	4	2400
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc100	0.045158049	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc120	0.045158049	10	7500	2000	0	0
Patuxent						
no ITC/MACRS						

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacity [kW]	Storage [number of units]	Total Storage Capacity [kWh]
Wholesale Market (Volatile)						
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellNoInc120	0.060477286	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonNoInc120	0.060477286	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetNoInc120	0.060283363	9	6750	2000	2	900
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosNoInc120	0.060477286	10	7500	2000	0	0
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKNoInc120	0.060477286	10	7500	2000	0	0
Patuxent						
with ITC/MACRS						
Wholesale Market (Volatile)						
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellInc120	0.060322334	9	6750	2000	3	960
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonInc120	0.06024639	9	6750	2000	73	2190
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetInc120	0.0601867	9	6750	2000	2	900
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosInc120	0.06018003	9	6750	2000	4	2400
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKInc120	0.060477286	10	7500	2000	0	0
Ventura	**Microgrid O&M Costs [k$]**					
no ITC/MACRS	**100**					
Behind the Meter						
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc100	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc120	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc100	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc120	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc100	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc120	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc100	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc120	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc100	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc120	0.089292564	5	3750	830	0	0
Ventura						
with ITC/MACRS						
Behind the Meter						
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc100	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc120	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc100	0.089285866	5	3750	830	10	300
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc120	0.089240216	5	3750	830	15	450
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc100	0.089266596	5	3750	830	1	450
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc120	0.089216299	5	3750	830	1	450

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacity [kW]	Storage [number of units]	Total Storage Capacity [kWh]
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc100	0.089269791	5	3750	830	1	600
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc120	0.089216791	5	3750	830	1	600
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc100	0.089292564	5	3750	830	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc120	0.089292564	5	3750	830	0	0
Ventura						
no ITC/MACRS						
Wholesale Market (Current)						
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc100	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc120	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc100	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc120	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc100	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc120	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc100	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc120	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc100	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc120	0.05523212	5	3750	830	0	0
Ventura						
with ITC/MACRS						
Wholesale Market (Current)						
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc100	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc120	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc100	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc120	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc100	0.054796853	5	3750	830	5	2250
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc120	0.054554946	5	3750	830	7	3150
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc100	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc120	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc100	0.05523212	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc120	0.05523212	5	3750	830	0	0
Ventura						
no ITC/MACRS						
Wholesale Market (Volatile)						
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellNoInc120	0.073862224	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonNoInc120	0.073862224	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetNoInc120	0.073862224	5	3750	830	0	0

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacity [kW]	Storage [number of units]	Total Storage Capacity [kWh]
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosNoInc120	0.073862224	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKNoInc120	0.073862224	5	3750	830	0	0
Ventura						
with ITC/MACRS						
Wholesale Market (Volatile)						
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellInc120	0.073862224	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonInc120	0.073862224	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetInc120	0.071595192	5	3750	830	7	3150
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosInc120	0.073862224	5	3750	830	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKInc120	0.073862224	5	3750	830	0	0
Westover	**Microgrid O&M Costs [k$]**					
no ITC/MACRS	**67**					
Behind the Meter (Current)						
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc100	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc100	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc100	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc100	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc100	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc120	0.114858747	2	1500	2000	0	0
Westover						
with ITC/MACRS						
Behind the Meter (Current)						
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc100	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc100	0.102051829	2	1500	2000	298	8940
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc120	0.100813724	2	1500	2000	298	8940
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc100	0.108265639	2	1500	2000	19	8550
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc120	0.106242828	2	1500	2000	20	9000
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc100	0.099727652	2	1500	2000	14	8400
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc120	0.098377282	2	1500	2000	14	8400
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc100	0.10224614	2	1500	2000	7	8400
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc120	0.100699542	2	1500	2000	7	8400

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacit y [kW]	Storage [numbe r of units]	Total Storage Capacity [kWh]
Westover						
no ITC/MACRS						
Wholesale Market (Current)						
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc100	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc120	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc100	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc120	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc100	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc120	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc100	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc120	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc100	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc120	0.077108371	2	1500	2000	0	0
Westover						
with ITC/MACRS						
Wholesale Market (Current)						
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc100	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc120	0.077108371	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc100	0.064384525	2	1500	2000	298	8940
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc120	0.063146622	2	1500	2000	298	8940
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc100	0.070593255	2	1500	2000	19	8550
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc120	0.06898425	2	1500	2000	19	8550
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc100	0.060917626	2	1500	2000	15	9000
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc120	0.059486057	2	1500	2000	15	9000
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc100	0.064497397	2	1500	2000	7	8400
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc120	0.062950595	2	1500	2000	7	8400
Westover						
no ITC/MACRS						
Behind the Meter (Volatile)						
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_AllCellNoInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_AvalonNoInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_BluePlanetNoInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_EosNoInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_NGKNoInc120	0.114858747	2	1500	2000	0	0
Westover						
with ITC/MACRS						

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Number Diesel Generator Units	Total Diesel Generator Capacity [kW]	PV Capacity [kW]	Storage [number of units]	Total Storage Capacity [kWh]
Behind the Meter (Volatile)						
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_AllCellInc120	0.114858747	2	1500	2000	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_AvalonInc120	0.06986408	2	1500	2000	298	8940
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_BluePlanetInc120	0.078147282	2	1500	2000	20	9000
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_EosInc120	0.070002042	2	1500	2000	14	8400
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_NGKInc120	0.071598456	2	1500	2000	7	8400
Westover						
no ITC/MACRS						
Wholesale Market (Volatile)						
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellNoInc120	0.093721011	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonNoInc120	0.093721011	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetNoInc120	0.093721011	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosNoInc120	0.093721011	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKNoInc120	0.093721011	2	1500	2000	0	0
Westover						
with ITC/MACRS						
Wholesale Market (Volatile)						
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellInc120	0.093721011	2	1500	2000	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonInc120	0.047561314	2	1500	2000	298	8940
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetInc120	0.05709062	2	1500	2000	19	8550
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosInc120	0.04547408	2	1500	2000	15	9000
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKInc120	0.04944521	2	1500	2000	7	8400

APPENDIX A4. CAPITAL COSTS

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Total Upfront CAPEX [k$] [with Infrastructure]	UPS Upfront CAPEX [k$]	Total Diesel Generator Upfront CAPEX [k$]	Total Storage Upfront CAPEX [k$]	Total BOS Hardware Cost [k$]	Total Storage Unit Cost [k$]
Fort Bliss	**Microgrid O&M Costs [k$]**						
no ITC/MACRS	**100**						
FortBliss_Scenario2c_Current_AvgMonthlyPV_AllCellNoInc100	0.065763867	12015.11393	3888	7200	665.56026	329.5602576	336.0000024
FortBliss_Scenario2c_Current_AvgMonthlyPV_AllCellNoInc120	0.065682763	12015.11393	3888	7200	665.56026	329.5602576	336.0000024
FortBliss_Scenario2c_Current_AvgMonthlyPV_AvalonNoInc100	0.065699228	12980.87915	3888	7200	1631.32548	617.9254831	1013.399997
FortBliss_Scenario2c_Current_AvgMonthlyPV_AvalonNoInc120	0.065658193	12980.87915	3888	7200	1631.32548	617.9254831	1013.399997
FortBliss_Scenario2c_Current_AvgMonthlyPV_BluePlanetNoInc100	0.065529745	12243.51641	3888	7200	893.96274	308.9627415	584.9999985
FortBliss_Scenario2c_Current_AvgMonthlyPV_BluePlanetNoInc120	0.065496961	12243.51641	3888	7200	893.96274	308.9627415	584.9999985
FortBliss_Scenario2c_Current_AvgMonthlyPV_EosNoInc100	0.065729275	12749.45431	3888	7200	1399.90064	823.9006441	575.9999959
FortBliss_Scenario2c_Current_AvgMonthlyPV_EosNoInc120	0.065671261	12749.45431	3888	7200	1399.90064	823.9006441	575.9999959
FortBliss_Scenario2c_Current_AvgMonthlyPV_NGKNoInc100	0.06576399	12549.55367	3888	8400	0	0	0
FortBliss_Scenario2c_Current_AvgMonthlyPV_NGKNoInc120	0.06576399	12549.55367	3888	8400	0	0	0
Fort Bliss							
with ITC/MACRS							
FortBliss_Scenario2c_Current_AvgMonthlyPV_AllCellInc100	0.065486576	11635.96136	3888	7200	286.40769	141.8182494	144.5894406
FortBliss_Scenario2c_Current_AvgMonthlyPV_AllCellInc120	0.065443615	11635.96136	3888	7200	286.40769	141.8182494	144.5894406
FortBliss_Scenario2c_Current_AvgMonthlyPV_AvalonInc100	0.065496176	12051.55495	3888	7200	702.00128	265.9092175	436.0920625
FortBliss_Scenario2c_Current_AvgMonthlyPV_AvalonInc120	0.06547046	12051.55495	3888	7200	702.00128	265.9092175	436.0920625
FortBliss_Scenario2c_Current_AvgMonthlyPV_BluePlanetInc100	0.06551207	12311.29153	3888	7200	961.73786	332.3865219	629.3513381
FortBliss_Scenario2c_Current_AvgMonthlyPV_BluePlanetInc120	0.065518498	12503.6391	3888	7200	1154.08543	398.8638263	755.2216037
FortBliss_Scenario2c_Current_AvgMonthlyPV_EosInc100	0.065475869	11951.9669	3888	7200	602.41323	354.5456234	247.8676066
FortBliss_Scenario2c_Current_AvgMonthlyPV_EosInc120	0.06544285	11951.9669	3888	7200	602.41323	354.5456234	247.8676066
FortBliss_Scenario2c_Current_AvgMonthlyPV_NGKInc100	0.065638795	12373.48225	3888	7200	1023.92858	531.8184351	492.1101449
FortBliss_Scenario2c_Current_AvgMonthlyPV_NGKInc120	0.065592566	12373.48225	3888	7200	1023.92858	531.8184351	492.1101449
Holloman	**Microgrid O&M Costs [k$]**						
no ITC/MACRS	**100**						
Holloman_Scenario2c_Current_AvgMonthlyPV_AllCellNoInc100	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_AllCellNoInc120	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_AvalonNoInc100	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_AvalonNoInc120	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_BluePlanetNoInc100	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_BluePlanetNoInc120	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_EosNoInc100	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_EosNoInc120	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_NGKNoInc100	0.084639481	6301.803671	2102.75	3937.5	0	0	0

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Total Upfront CAPEX [k$] [with Infrastructure]	UPS Upfront CAPEX [k$]	Total Diesel Generator Upfront CAPEX [k$]	Total Storage Upfront CAPEX [k$]	Total BOS Hardware Cost [k$]	Total Storage Unit Cost [k$]
Holloman_Scenario2c_Current_AvgMonthlyPV_NGKNoInc120	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman							
with ITC/MACRS							
Holloman_Scenario2c_Current_AvgMonthlyPV_AllCellInc100	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_AllCellInc120	0.084573793	6216.649811	2102.75	3375	477.34614	236.3637489	240.9823911
Holloman_Scenario2c_Current_AvgMonthlyPV_AvalonInc100	0.0845213	6956.105901	2102.75	3375	1216.80223	460.9093104	755.8929196
Holloman_Scenario2c_Current_AvgMonthlyPV_AvalonInc120	0.084382007	6956.105901	2102.75	3375	1216.80223	460.9093104	755.8929196
Holloman_Scenario2c_Current_AvgMonthlyPV_BluePlanetInc100	0.084259943	6508.693961	2102.75	3375	769.39029	265.9092175	503.4810725
Holloman_Scenario2c_Current_AvgMonthlyPV_BluePlanetInc120	0.084137384	6508.693961	2102.75	3375	769.39029	265.9092175	503.4810725
Holloman_Scenario2c_Current_AvgMonthlyPV_EosInc100	0.084451993	6642.923511	2102.75	3375	903.61984	531.8184351	371.8014049
Holloman_Scenario2c_Current_AvgMonthlyPV_EosInc120	0.084278151	6642.923511	2102.75	3375	903.61984	531.8184351	371.8014049
Holloman_Scenario2c_Current_AvgMonthlyPV_NGKInc100	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Holloman_Scenario2c_Current_AvgMonthlyPV_NGKInc120	0.084639481	6301.803671	2102.75	3937.5	0	0	0
Patuxent	**Microgrid O&M Costs [k$]**						
no ITC/MACRS	**133**						
Behind the Meter							
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc100	0.100084067	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc120	0.100084067	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc100	0.100084067	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc120	0.100084067	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc100	0.100013355	9054.950968	2749.75	5062.5	893.96274	308.9627415	584.9999985
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc120	0.099950221	9054.950968	2749.75	5062.5	893.96274	308.9627415	584.9999985
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc100	0.100084067	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc120	0.100084067	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc100	0.100084067	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc120	0.100084067	8723.488228	2749.75	5625	0	0	0
Patuxent							
with ITC/MACRS							
Behind the Meter							
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc100	0.099983619	8447.395918	2749.75	5062.5	286.40769	141.8182494	144.5894406
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc120	0.099902534	8447.395918	2749.75	5062.5	286.40769	141.8182494	144.5894406
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc100	0.099894381	9015.089788	2749.75	5062.5	854.10156	323.5228813	530.5786787
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc120	0.099839279	9015.089788	2749.75	5062.5	854.10156	323.5228813	530.5786787
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc100	0.099817397	8545.683368	2749.75	5062.5	384.69514	132.9546088	251.7405312
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc120	0.099772985	8545.683368	2749.75	5062.5	384.69514	132.9546088	251.7405312
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc100	0.099845585	8763.401458	2749.75	5062.5	602.41323	354.5456234	247.8676066
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc120	0.099782083	8763.401458	2749.75	5062.5	602.41323	354.5456234	247.8676066
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc100	0.100084067	8723.488228	2749.75	5625	0	0	0

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Total Upfront CAPEX [k$] [with Infrastructure]	UPS Upfront CAPEX [k$]	Total Diesel Generator Upfront CAPEX [k$]	Total Storage Upfront CAPEX [k$]	Total BOS Hardware Cost [k$]	Total Storage Unit Cost [k$]
Patuxent_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc120	0.100084067	8723.488228	2749.75	5625	0	0	0
Patuxent							
no ITC/MACRS							
Wholesale Market (Current)							
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc100	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc120	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc100	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc120	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc100	0.0451051	9054.950968	2749.75	5062.5	893.96274	308.9627415	584.9999985
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc120	0.045041968	9054.950968	2749.75	5062.5	893.96274	308.9627415	584.9999985
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc100	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc120	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc100	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc120	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent							
with ITC/MACRS							
Wholesale Market (Current)							
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc100	0.045103347	8447.395918	2749.75	5062.5	286.40769	141.8182494	144.5894406
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc120	0.04502227	8447.395918	2749.75	5062.5	286.40769	141.8182494	144.5894406
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc100	0.045021074	9015.089788	2749.75	5062.5	854.10156	323.5228813	530.5786787
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc120	0.044965979	9015.089788	2749.75	5062.5	854.10156	323.5228813	530.5786787
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc100	0.044936232	8545.683368	2749.75	5062.5	384.69514	132.9546088	251.7405312
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc120	0.044891817	8545.683368	2749.75	5062.5	384.69514	132.9546088	251.7405312
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc100	0.044965116	8763.401458	2749.75	5062.5	602.41323	354.5456234	247.8676066
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc120	0.044901622	8763.401458	2749.75	5062.5	602.41323	354.5456234	247.8676066
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc100	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc120	0.045158049	8723.488228	2749.75	5625	0	0	0
Patuxent							
no ITC/MACRS							
Wholesale Market (Volatile)							
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellNoInc120	0.060477286	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonNoInc120	0.060477286	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetNoInc120	0.060283363	9054.950968	2749.75	5062.5	893.96274	308.9627415	584.9999985
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosNoInc120	0.060477286	8723.488228	2749.75	5625	0	0	0
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKNoInc120	0.060477286	8723.488228	2749.75	5625	0	0	0
Patuxent							
with ITC/MACRS							
Wholesale Market (Volatile)							

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Total Upfront CAPEX [k$] [with Infrastructure]	UPS Upfront CAPEX [k$]	Total Diesel Generator Upfront CAPEX [k$]	Total Storage Upfront CAPEX [k$]	Total BOS Hardware Cost [k$]	Total Storage Unit Cost [k$]
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellInc120	0.060322334	8447.395918	2749.75	5062.5	286.40769	141.8182494	144.5894406
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonInc120	0.06024639	9015.089788	2749.75	5062.5	854.10156	323.5228813	530.5786787
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetInc120	0.0601867	8545.683368	2749.75	5062.5	384.69514	132.9546088	251.7405312
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosInc120	0.06018003	8763.401458	2749.75	5062.5	602.41323	354.5456234	247.8676066
Patuxent_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKInc120	0.060477286	8723.488228	2749.75	5625	0	0	0
Ventura	**Microgrid O&M Costs [k$]**						
no ITC/MACRS	**100**						
Behind the Meter							
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc100	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc120	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc100	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc120	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc100	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc120	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc100	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc120	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc100	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc120	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura							
with ITC/MACRS							
Behind the Meter							
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc100	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc120	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc100	0.089285866	4646.803881	1455.75	2812.5	117.00021	44.31820292	72.68200708
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc120	0.089240216	4705.303991	1455.75	2812.5	175.50032	66.47730438	109.0230156
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc100	0.089266596	4722.151241	1455.75	2812.5	192.34757	66.47730438	125.8702656
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc120	0.089216299	4722.151241	1455.75	2812.5	192.34757	66.47730438	125.8702656
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc100	0.089269791	4680.406981	1455.75	2812.5	150.60331	88.63640584	61.96690416
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc120	0.089216791	4680.406981	1455.75	2812.5	150.60331	88.63640584	61.96690416
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc100	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc120	0.089292564	4529.803671	1455.75	2812.5	0	0	0
Ventura							
no ITC/MACRS							
Wholesale Market (Current)							
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc100	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc120	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc100	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc120	0.05523212	4529.803671	1455.75	2812.5	0	0	0

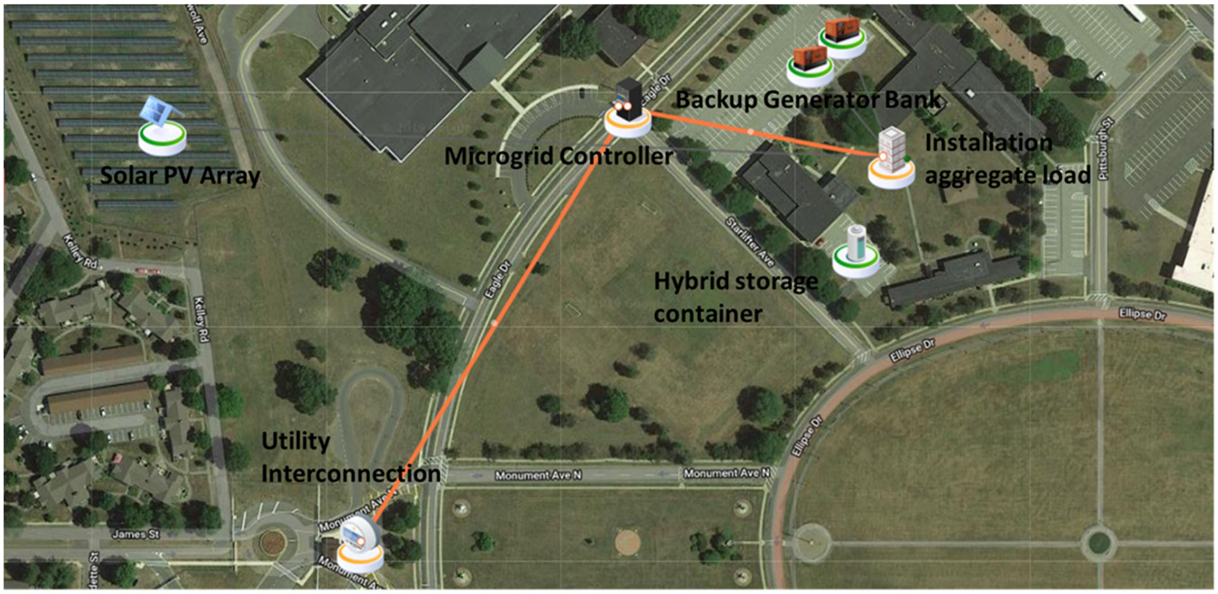
Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Total Upfront CAPEX [k$] [with Infrastructure]	UPS Upfront CAPEX [k$]	Total Diesel Generator Upfront CAPEX [k$]	Total Storage Upfront CAPEX [k$]	Total BOS Hardware Cost [k$]	Total Storage Unit Cost [k$]
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc100	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc120	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc100	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc120	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc100	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc120	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura							
with ITC/MACRS							
Wholesale Market (Current)							
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc100	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc120	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc100	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc120	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc100	0.054796853	5491.541531	1455.75	2812.5	961.73786	332.3865219	629.3513381
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc120	0.054554946	5876.236681	1455.75	2812.5	1346.43301	465.3411307	881.0918793
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc100	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc120	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc100	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc120	0.05523212	4529.803671	1455.75	2812.5	0	0	0
Ventura							
no ITC/MACRS							
Wholesale Market (Volatile)							
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellNoInc120	0.073862224	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonNoInc120	0.073862224	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetNoInc120	0.073862224	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosNoInc120	0.073862224	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKNoInc120	0.073862224	4529.803671	1455.75	2812.5	0	0	0
Ventura							
with ITC/MACRS							
Wholesale Market (Volatile)							
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellInc120	0.073862224	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonInc120	0.073862224	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetInc120	0.071595192	5876.236681	1455.75	2812.5	1346.43301	465.3411307	881.0918793
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosInc120	0.073862224	4529.803671	1455.75	2812.5	0	0	0
Ventura_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKInc120	0.073862224	4529.803671	1455.75	2812.5	0	0	0
Westover	**Microgrid O&M Costs [k$]**						
no ITC/MACRS	**67**						
Behind the Meter (Current)							

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Total Upfront CAPEX [k$] [with Infrastructure]	UPS Upfront CAPEX [k$]	Total Diesel Generator Upfront CAPEX [k$]	Total Storage Upfront CAPEX [k$]	Total BOS Hardware Cost [k$]	Total Storage Unit Cost [k$]
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc100	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc100	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc100	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc100	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc100	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover							
with ITC/MACRS							
Behind the Meter (Current)							
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc100	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AllCellInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc100	0.102051829	5594.725494	808.75	1125	3486.60638	1320.682447	2165.923933
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_AvalonInc120	0.100813724	5594.725494	808.75	1125	3486.60638	1320.682447	2165.923933
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc100	0.108265639	5762.722984	808.75	1125	3654.60387	1263.068783	2391.535087
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_BluePlanetInc120	0.106242828	5955.070564	808.75	1125	3846.95145	1329.546088	2517.405362
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc100	0.099727652	4216.565414	808.75	1125	2108.4463	1240.909682	867.5366182
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_EosInc120	0.098377282	4216.565414	808.75	1125	2108.4463	1240.909682	867.5366182
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc100	0.10224614	4497.285804	808.75	1125	2389.16669	1240.909682	1148.257008
Westover_Scenario2c_BehindMeter_Current_AvgMonthlyPV_NGKInc120	0.100699542	4497.285804	808.75	1125	2389.16669	1240.909682	1148.257008
Westover							
no ITC/MACRS							
Wholesale Market (Current)							
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc100	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellNoInc120	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc100	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonNoInc120	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc100	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetNoInc120	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc100	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosNoInc120	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc100	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKNoInc120	0.077108371	2108.119114	808.75	1125	0	0	0
Westover							
with ITC/MACRS							

Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Total Upfront CAPEX [k$] [with Infrastructure]	UPS Upfront CAPEX [k$]	Total Diesel Generator Upfront CAPEX [k$]	Total Storage Upfront CAPEX [k$]	Total BOS Hardware Cost [k$]	Total Storage Unit Cost [k$]
Wholesale Market (Current)							
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc100	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AllCellInc120	0.077108371	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc100	0.064384525	5594.725494	808.75	1125	3486.60638	1320.682447	2165.923933
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_AvalonInc120	0.063146622	5594.725494	808.75	1125	3486.60638	1320.682447	2165.923933
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc100	0.070593255	5762.722984	808.75	1125	3654.60387	1263.068783	2391.535087
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_BluePlanetInc120	0.06898425	5762.722984	808.75	1125	3654.60387	1263.068783	2391.535087
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc100	0.060917626	4367.168714	808.75	1125	2259.0496	1329.546088	929.5035123
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_EosInc120	0.059486057	4367.168714	808.75	1125	2259.0496	1329.546088	929.5035123
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc100	0.064497397	4497.285804	808.75	1125	2389.16669	1240.909682	1148.257008
Westover_Scenario2c_Wholesale_Current_AvgMonthlyPV_NGKInc120	0.062950595	4497.285804	808.75	1125	2389.16669	1240.909682	1148.257008
Westover							
no ITC/MACRS							
Behind the Meter (Volatile)							
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_AllCellNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_AvalonNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_BluePlanetNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_EosNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_NGKNoInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover							
with ITC/MACRS							
Behind the Meter (Volatile)							
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_AllCellInc120	0.114858747	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_AvalonInc120	0.06986408	5594.725494	808.75	1125	3486.60638	1320.682447	2165.923933
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_BluePlanetInc120	0.078147282	5955.070564	808.75	1125	3846.95145	1329.546088	2517.405362
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_EosInc120	0.070002042	4216.565414	808.75	1125	2108.4463	1240.909682	867.5366182
Westover_Scenario2c_BehindMeter_Volatile_AvgMonthlyPV_NGKInc120	0.071598456	4497.285804	808.75	1125	2389.16669	1240.909682	1148.257008
Westover							
no ITC/MACRS							
Wholesale Market (Volatile)							
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellNoInc120	0.093721011	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonNoInc120	0.093721011	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetNoInc120	0.093721011	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosNoInc120	0.093721011	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKNoInc120	0.093721011	2108.119114	808.75	1125	0	0	0
Westover							
with ITC/MACRS							

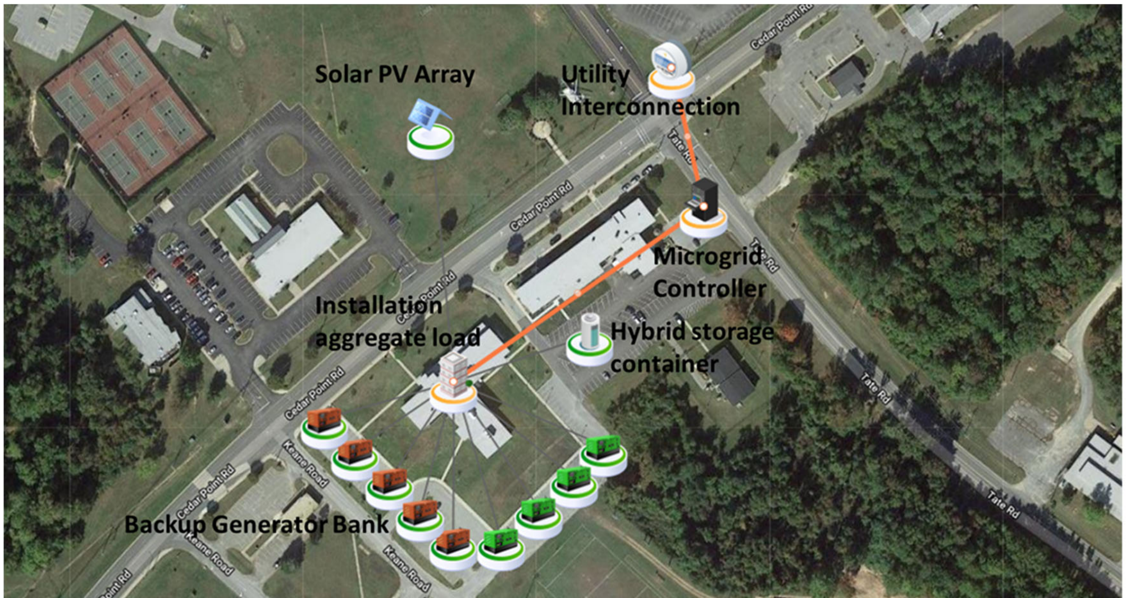
Scenario	LCOE [$/kWh] (with infrastructure AND correct demand charges)	Total Upfront CAPEX [k$] [with Infrastructure]	UPS Upfront CAPEX [k$]	Total Diesel Generator Upfront CAPEX [k$]	Total Storage Upfront CAPEX [k$]	Total BOS Hardware Cost [k$]	Total Storage Unit Cost [k$]
Wholesale Market (Volatile)							
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AllCellInc120	0.093721011	2108.119114	808.75	1125	0	0	0
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_AvalonInc120	0.047561314	5594.725494	808.75	1125	3486.60638	1320.682447	2165.923933
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_BluePlanetInc120	0.05709062	5762.722984	808.75	1125	3654.60387	1263.068783	2391.535087
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_EosInc120	0.04547408	4367.168714	808.75	1125	2259.0496	1329.546088	929.5035123
Westover_Scenario2c_Wholesale_Volatile_AvgMonthlyPV_NGKInc120	0.04944521	4497.285804	808.75	1125	2389.16669	1240.909682	1148.257008

APPENDIX A5. SIMPLIFIED FACILITY MICROGRID SCHEMATICS



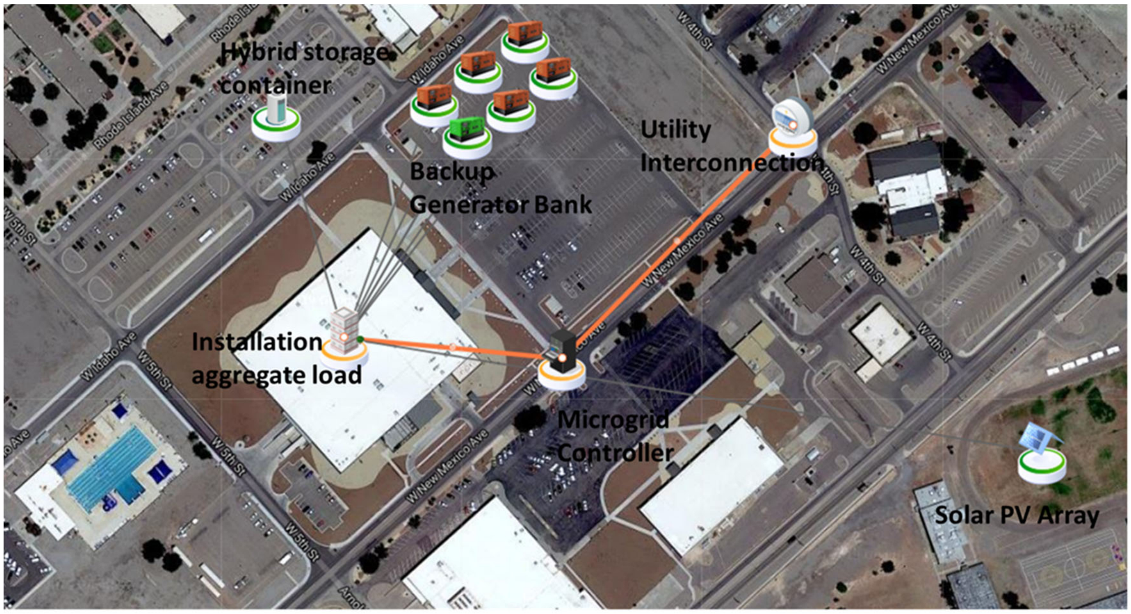
Westover simplified microgrid

Fort Bliss simplified microgrid



NAS Patuxent River simplified microgrid

Ventura simplified microgrid



Holloman simplified microgrid