Application of Joint Exelon Utilities for Approval of Energy Storage Pilot Projects

Case No. 9619

Exelon Utilities
April 15, 2020

Contents

1.0 Energy Storage Projects Filing

1.1 Overview

Contained herein for consideration and approval by the Public Service Commission of Maryland (the "Commission") are six Maryland energy storage project proposals developed by Baltimore Gas and Electric Company ("BGE"), Delmarva Power & Light Company ("Delmarva Power"), and Potomac Electric Power Company ("Pepco") (and collectively with BGE and Delmarva Power, the "the Joint Exelon Utilities" or "the Companies"). These energy storage project proposals were developed in compliance with the Maryland Energy Storage Pilot Project Act (the "Act"), SB573, signed into law by Governor Hogan on May 13, 2019. The Act created Section 7-216 of the Public Utilities Article, Annotated Code of Maryland, and requires the Commission to establish an energy storage pilot program. On August 23, 2019, the Commission issued Order No. 89240, docketing Case No. 9619, establishing the Commission's Energy Storage Pilot Program, and directing each Maryland investor-owned electric utility ("IOU") to solicit offers to develop energy storage projects and submit applications for those projects to the Commission for consideration and approval. Each of BGE, Delmarva Power, and Pepco are hereby submitting two energy storage project proposals for a total of six project applications.

The Joint Exelon Utilities are submitting applications for all six projects simultaneously to provide sufficient time for Commission review and, if approved, project construction and implementation to meet the Act's February 28, 2022, deadline for having all projects operational. The Joint Exelon Utilities respectfully request that the Commission issue an order on these applications no later than September 1, 2020. This would enable the implementation of each energy storage project to begin no later than the fourth quarter of 2021 and be operational by the February 28, 2022, deadline. The Act allows the Commission to extend the start date due to unforeseen delays. Approval after September 1, 2020, could result in later operational dates for the storage projects.

1.2 Policy Background

The Act and Commission Order No. 89240 require that each Maryland IOU submit at least two energy storage projects to the Commission in 2020, one of which may not be owned by the IOU. The collective total capacity across all four Maryland IOUs and battery energy storage system ("BESS") projects must be between 5 and 10 megawatts ("MW") with at least 15 megawatt-hours ("MWh") of energy storage capability.

The Act describes four Commercial and Regulatory Models ("Models") and requires that all IOUs issue solicitations (but not necessarily procure) under all the Models. See Table 1 below for descriptions of the ownership, placement, and operations characteristics of each of the Models.

Table 1: Commercial and Regulatory Models

Models	**BTM or FTM**[1]	**BESS Owner**	**Storage Control for Grid Reliability**	**Operation in Wholesale Markets or Other Applications**
1. IOU Only	FTM	IOU	IOU	IOU
2. IOU and 3rd Party Operation	FTM	IOU	IOU	3rd Party
3. 3rd Party Ownership	BTM or FTM	3rd Party	IOU contract with 3rd Party	3rd Party
4. Virtual Power Plant (VPP)	BTM	Customer(s) or 3rd Party	IOU or contract with 3rd Party Aggregator	3rd Party, Customer(s) or IOU Aggregation

[1] "BTM" stands for behind-the-meter and "FTM" stands for front-of-meter.

The Act describes the four Models as follows:

Model 1:

> A "UTILITY–ONLY" MODEL UNDER WHICH THE ELECTRIC COMPANY WOULD OWN THE PROJECT, CONTROL THE PROJECT FOR GRID RELIABILITY, AND OPERATE THE PROJECT IN WHOLESALE MARKETS OR OTHER APPLICATIONS WHEN NOT PROVIDING GRID SERVICES.

Model 2:

> A "UTILITY AND THIRD–PARTY" MODEL UNDER WHICH THE ELECTRIC COMPANY WOULD OWN THE PROJECT AND CONTROL THE PROJECT FOR GRID RELIABILITY, AND A THIRD PARTY WOULD OPERATE THE PROJECT IN WHOLESALE MARKETS OR OTHER APPLICATIONS WHEN THE PROJECT IS NOT PROVIDING GRID SERVICES.

Model 3:

> A "THIRD–PARTY OWNERSHIP" MODEL UNDER WHICH THE ELECTRIC COMPANY WOULD CONTRACT WITH A PROJECT OWNED BY A THIRD PARTY FOR GRID RELIABILITY; AND ALLOW THE THIRD PARTY TO OPERATE THE PROJECT IN WHOLESALE MARKETS OR OTHER APPLICATIONS WHEN THE PROJECT IS NOT PROVIDING GRID SERVICES.

Model 4:

> A "VIRTUAL POWER PLANT" MODEL UNDER WHICH THE ELECTRIC COMPANY WOULD AGGREGATE OR USE A THIRD–PARTY AGGREGATOR TO RECEIVE GRID SERVICES FROM DISTRIBUTED ENERGY STORAGE PROJECTS OWNED BY CUSTOMERS OR A THIRD PARTY; AND THE PROJECTS WOULD BE USED BY THE CUSTOMERS OR THIRD PARTY FOR OTHER APPLICATIONS WHEN THE PROJECTS ARE NOT PROVIDING GRID SERVICES.

1.3 Project Selection and Size

BGE, Delmarva Power, and Pepco each identified potential projects based upon the expected benefits from each project, including utility distribution cost savings, system reliability improvements, conformance with the requirements of the Act and Commission Order 89240, potential business model, and learnings benefits. BGE identified a distribution system constraint in its electric distribution system territory south of Annapolis, Maryland, and pursued two projects in that geographic area: the Chesapeake Beach Project ("Chesapeake Beach") and the BESS at BGE's Fairhaven Substation ("Fairhaven"). Pepco selected projects at National Harbor/Livingston Road in Prince George's County and the Montgomery County Electric Bus Depot. Delmarva Power pursued projects at Elk Neck State Park in Cecil County and in Ocean City, Maryland.

The Companies also worked with The Potomac Edison Company to ensure that the total size of statewide BESS projects does not exceed the Act's statewide capacity ceiling of 10 MW while meeting or exceeding the minimum required energy duration of 15 MWh. Please see Table 2 below for the capacities of the six energy storage projects proposed by the Joint Exelon Utilities. The six projects have an aggregate requirement of 7 MW and 16 MWh of guaranteed capacity over a 10-year period. Please refer to each IOU's section of this document for a description of each proposed project, the rationale for the project, the expected project vendor, project cost estimates, and the expected quantified and unquantified benefits from the project.

Table 2: Proposed Joint Exelon Utilities Projects

	BGE		Delmarva Power		PEPCO		
Project Description	**Chesapeake Beach Project**	**BESS at Fairhaven Substation Project**	**Elk Neck, Maryland Project**	**Ocean City, Maryland Project**	**National Harbor/ Livingston Road Project**	**Montgomery County Electric Bus Depot Project**	**Total**
Capacity	1.0 MW	2.5 MW	0.5 MW	1.0 MW	1.0 MW	1.0 MW	7.0 MW
Guaranteed End of Life Usable Capacity	1.5MWh	4.0 MWh	1.5 MWh	3.0 MWh	3.0 MWh	3.0 MWh	16.0 MWh
Initial Usable Capacity	2.0 MWh	7.1 MWh	2.2 MWh	3.6 MWh	4.3 MWh	4.3 MWh	23.5 MWh
Model 1: Utility Owned and Utility Operated		X		X			2
Model 2: Utility Owned and Third Party Operated					X		1
Model 3: Third Party Owned and Third Party Operated	X					X	2
Model 4: Virtual Power Plant			X				1

1.4 Timeline Implications

The Joint Exelon Utilities acknowledge that timelines for the energy storage pilot program are set forth in the Act. However, in the process of soliciting energy storage project offers, speaking to storage developers, and creating internal development timelines, the Joint Exelon Utilities note the possibility that the energy storage projects may not be operational by the February 28, 2022, deadline specified in the Act absent Commission approval by September 1, 2020. Proposals received by the Joint Exelon Utilities highlighted the uncertainty related to site permitting, procurement of the battery system, PJM interconnection, commissioning and testing.

The Joint Exelon Utilities want to provide adequate time to install safe, reliable and effective systems by the deadlines imposed by the Act and the Commission.

Consequently, the Joint Exelon Utilities expect that 18 months are needed to progress from vendor contract execution to project operational date. This means that for all projects to meet the February 28, 2022, statutory deadline, the Commission would need to provide approval of the projects by September 1, 2020, to avoid risking delay to operational deadlines. The Joint Exelon Utilities therefore propose that a Commission order be issued by September 1, 2020, or that any Commission approval beyond September 1, 2020, be followed by an extension of the February 22, 2022, operational deadline equal to the number of months beyond September 1, 2020, that the approval is issued. The Joint Exelon Utilities respectfully propose the timeline for the Commission's energy storage pilot program set forth in Table 3 below.

Table 3: Proposed Timeline to Meet Operational Deadlines

Date	Milestone
April 15, 2020	Four IOUs file 8 Storage Pilot Projects with the Commission
April 24, 2020	Commission issues notice for Stakeholder Comments
June 1, 2020	Stakeholder Comments are due
June 19, 2020	Utilities Response to Intervener Comments
July 2, 2020	Legislative-Style Hearing on Project Applications
September 1, 2020	Commission Decision

2.0 Solicitation Process

2.1 Request for Information (RFI) Development and Response

The Joint Exelon Utilities' first step in the vendor solicitation process for the energy storage projects was the preparation and issuance of a Request for Information ("RFI") to identify vendor interest in energy storage pilot projects, recommendations, and capabilities. The Joint Exelon Utilities issued a joint RFI on October 2, 2019, to 65 potential energy storage vendors. The list of vendors invited to participate was prepared in consultation with the Energy Storage Association ("ESA") to help ensure that a wide variety of vendors would have an opportunity to propose projects. The type of energy storage technology was not specified in the RFI to allow respondents the largest possible latitude to recommend alternative storage technologies. Seven (7) vendors responded to the RFI and shared their interest, capabilities, and recommended approaches.

2.2 Request for Proposal (RFP) Development and Response

After receipt of the RFI responses, the Companies developed and issued two Requests for Proposals ("RFPs") soliciting energy storage project proposals from eighty-seven (87) vendors. The RFPs were designed to include project installation, energy storage technology, and project maintenance/operation over a 10-year operational period beginning in 2022. The Companies consulted again with ESA to develop a comprehensive list of energy storage vendors to invite to respond to the RFP.

The Joint Exelon Utilities released a joint RFP for Delmarva Power's two projects, Pepco's two projects, and BGE's Fairhaven project. Due to the size and complexity of this solicitation, the Joint Exelon Utilities retained consulting firm Sargent & Lundy to assist in the creation of the RFP. BGE released a separate RFP for the Chesapeake Beach project.

Table 4 below provides a summary of the vendor responses to the issued RFPs. Seventeen (17) vendors submitted seventy-three (73) bids for BGE, Delmarva Power, and Pepco's respective technical teams and the Exelon Sourcing Group team reviewed the bid proposals, requested additional proposal information, and conducted vendor interviews as needed. Proposal selection was determined by the following criteria: 1) technical qualifications; 2) project experience; 3) commercial financial viability; 4) project timeline; 5) proposal characteristics; 6) project cost; and 7) the proposed business model. After final bid selection, the Exelon Sourcing Group will negotiate revised project pricing. As set forth in the PC44 Energy Storage Working Group's August 1, 2019, filing with the Commission, final contracts with selected vendors will be entered into by each respective utility following Commission approval of each specific project.

Table 4: Vendor Responses to the Joint Exelon Utilities' RFPs

	BGE		Delmarva Power		Pepco	
Vendor	**Chesapeake Beach Project**	**BESS at Fairhaven Substation Project**	**Elk Neck, Maryland PROJECT**	**Ocean City, Maryland PROJECT**	**National Harbor/ Livingston Road Project**	**Montgomery County Electric Bus Depot Project**
Project Vendor Count[2]	**5**	**8**	**5**	**11**	**9**	**11**
Project Proposal Count	**5**	**11**	**5**	**17**	**15**	**20**

[2] Vendor counts are not additive as counts represent unique vendors per project. Seventeen (17) unique vendors bid on the Joint Exelon Utilities projects as part of this storage pilot.

3.0 Baltimore Gas and Electric Company Projects

BGE investigated several locations within the BGE service territory to site a project. The constraint identified in Section 3.1 below proved the best-suited for storage because (a) there was a clearly identifiable traditional distribution system project that could be avoided with a viable energy storage alternative, (b) the peak shaving application allowed for a MW to MWh ratio that was favorable for battery pricing, (c) BGE's Fairhaven Substation provided a suitable location to host a utility-owned BESS, and (d) the large constrained area would allow locational flexibility for a third-party project and the ability to host two separate pilot BESS projects.

3.0.1 Communication

BGE will work with local government officials, non-profits and customers to explain the benefits of energy storage technology and share information regarding the purposes of the Commission's energy storage pilot program. Specifically, BGE plans to engage directly with county and state-level leaders, and work together to craft a communication program that educates local customers and stakeholders about the project and its benefits, as well as address any concerns. BGE will also mail project letters to customers near construction. Depending on what local leaders would like, this could include communication through virtual town-halls as well as targeted bill inserts and emails.

3.0.2 Project Model Selection

For the Fairhaven project, BGE sought responses for Model 1 and Model 2 in their RFP, given that the project would be sited on utility-owned land inside a BGE substation. Of the eight vendors who submitted proposals, six submitted Model 1 proposals. BGE pursued a Model 1 project primarily for the reasons that there were relatively few proposals for Model 2, and the Model 1 proposals scored stronger on technical grounds.

BGE's second RFP sought responses for Model 3 and Model 4 for a third-party or customer-owned project, sited not on BGE property but still within the identified constrained geographical area. Of the five vendor proposals received by BGE, three fell under Model 3, one offered a Model 4, and one submitted a hybrid of Model 3 and Model 4. The greatest factor in

BGE pursuing a Model 3 project was cost, as the Model 3 projects provided superior economics. In addition, the chosen Model 3 project presented a superior technical configuration that could deliver the capacity reliably.[3]

3.1 Overview of Constraint

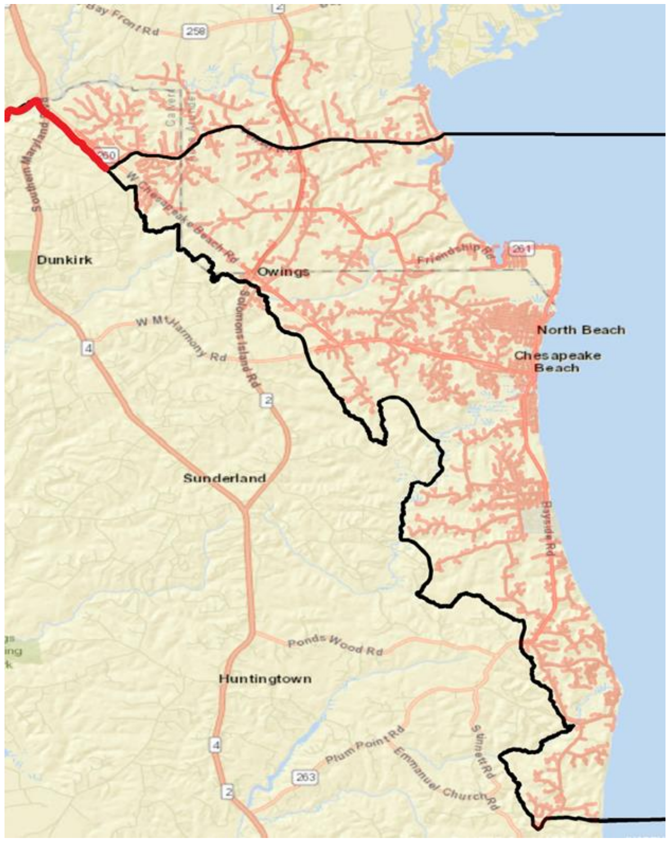
BGE has identified a 34kV feeder in southern Anne Arundel County that could experience a winter post-contingency overload of up to 3.5MW. Specifically, if BGE were to lose two of its Marriott Hill sub-transmission circuits, both on a single right-of-way and shared pole-line, customer load at three BGE substations would be transferred to an alternate Marriott Hill circuit. At peak load, this would result in the Marriott Hill alternate circuit exceeding its emergency rating. In February 2015, this contingency resulted in rotating customer load shed.

To address this overload, BGE considered possibly undergrounding approximately ten miles of one of the Marriott Hill circuits in order to separate the 34kV circuits on the shared pole-line. However, upgrades to the alternate Marriott Hill circuit and installing 3.5 MW/5.5 MWh of battery storage would allow BGE to eliminate the overload and the need for the undergrounding project. The required capacity was divided into two separate BESS projects that solve the same contingency overload. Accordingly, BGE is presenting both the Fairhaven and Chesapeake Beach projects to the Commission as a joint solution to the contingency overload.

The geographic area impacted by the contingency comprises three (3) BGE 34kV – 13kV substations and ten (10) 13kV feeders fed from those substations at the southern end of BGE's electric distribution service territory. The area has more than 9,000 customers and is enclosed in the black line in Figure 1 below. Spanning across portions of both Anne Arundel County and Calvert County, the area is bounded by Maryland Route 423 and the southern terminus of BGE's electric distribution service territory as shown.

[3] Note that BGE is still considering the possibility of offering a Model 4 Virtual Power Plant as a potential third energy storage project submission. Please see Section 3.4 below for more details.

Figure 1: Map of Constrained Area Outlined in Black



3.2 BESS at Fairhaven Substation Project

BGE is proposing the BESS at Fairhaven project sited at the Fairhaven Substation, to solve a 2.5 MW/4.0 MWh constraint. This project will be implemented as a BGE-owned, BGE-operated BESS under Model 1 of the pilot program. When not putting the facility into distribution grid reliability service, BGE will provide PJM services (see Section 3.2.2 below for additional details). ABB has been identified as the proposed developer for the project.

The BESS would be located inside the fence at BGE's Fairhaven Substation. Fairhaven is a 34kV – 13kV substation on Fairhaven Road in Tracy's Landing, Anne Arundel County, Maryland. The BESS would tie in to one of the 13kV feeders at the Fairhaven Substation via a medium voltage switchgear for protection.

To guarantee the required output during a peak shaving event through BESS end-of-life and allow participation in the PJM frequency regulation market, the system provides 2.5MW/ 7.1 MWh of usable capacity. This initial size considers battery degradation over the years due to planned operation while still meeting peak shaving requirements through the 10-year project term.

The BESS would include a Lithium Ion battery system with 7.1 MWhs of usable capacity stored in two (2) 48' x 8' battery containers, four (4) inverters, two (2) step-up transformers, controls and communication necessary to operate the BESS. Equipment listed above is based on a preliminary assessment and would be finalized during detailed design of the project. Set forth below in Table 5 is the key information related to the Fairhaven project.

Table 5: Key Information for BGE BESS at Fairhaven Project

Category	Project Information
Required Capacity for Grid Reliability through the 10-year project term	2.5 MW/4.0 MWh
Initial Usable Capacity	2.5 MW/7.1 MWh
Business Model	Model 1: Utility Only; BGE operates in grid reliability and in PJM, Front of the Meter (FTM)
Project Developer	ABB is the proposed developer
Energy Storage Technology	NMC Lithium Ion BESS
Primary Application	Grid Reliability and distribution infrastructure avoidance
Secondary Application	PJM Wholesale Services (Frequency Regulation, Energy Arbitrage, others)
Primary Location(s)	Fairhaven Substation in Southern Anne Arundel County
Expected Cost	$9.8 million ($9.0 million present value) for the 10-year term. For more detail, see section 3.2.5
Expected Net Savings (Cost)	On a Net Present Value Basis, Fairhaven will result in a net benefit of $3.8 million. For more detail, see Section 3.5.

3.2.1 Operations Description

BGE seeks discharge capacity during winter peak load times to mitigate contingency overload conditions. For grid reliability service, BGE will communicate with the control system of the BESS and send a signal to discharge during a potential contingency overload event. The

BESS will follow an interval kW signal from BGE during the full duration of the discharge event until the event is completed. The kW signal will not exceed 2.5 MW during the discharge event.

BGE expects to install a site-level BGE-owned remote terminal unit ("RTU") to enable communication between BGE's operations systems and the BESS controller. BGE plans to communicate with the RTU through wireless networks. BGE will connect the RTU to the BESS controller through a method to be negotiated with the project development vendor.

3.2.2 Other Applications

The primary purpose of the Fairhaven BESS is to enhance distribution system reliability. When not providing grid reliability services or undergoing maintenance, the BESS will participate in PJM market(s). Market participation will include frequency regulation service, and possibly other markets if the opportunities arise. This project will follow Model 1, where BGE will own the project, operate the project primarily for grid reliability purposes, and offer the project into applicable PJM wholesale markets when otherwise available.

3.2.3 Contract Description

The selected developer will act as a turnkey developer, providing engineering, procurement, and construction services to BGE. Most of the cost will be spread between 2020, 2021, and 2022 to pay for the containerized lithium ion battery as well as the inverter, switchgear, and 10-year warranty and performance guarantee. There will be an annual preventative maintenance contract in place as well.

3.2.4 Proposed Developer Information

ABB is the proposed developer for the Fairhaven project. ABB is a leading international industrial business, specializing in power and electrical markets, as well as robotics and automation. ABB operates in more than 100 countries and employs approximately 110,000 people. ABB's Grid Edge North American division is headquartered in Raleigh, North Carolina and is part of ABB's Power Grids Grid Automation team, which also houses the company's substation automation and wireless communications product groups. ABB's Power Grids group consists of 37,000 employees, 6,000 of whom are part of the Grid Automation team.

3.2.5 Cost Information

This section provides incremental cost estimates from two different perspectives. In Table 6 below, the estimates are presented on a cash flow cost basis over a 10-year term, and exclude complexities related to the project's effect on BGE's tax liability, amortization and other elements. On this basis, the total incremental cost of the Fairhaven project is expected to be $9.8 million or $9.0 million on a present value basis.[4] Of that total, approximately $6.9 million of the total cost over the 10-year term would be paid to the developer as part of this project, excluding contingency. Table 7 below estimates the revenue requirement calculation, which translates to actual costs to the end customer and necessarily includes tax, depreciation and amortization effects over a 15-year timeframe. Indirect costs such as general and administrative are excluded in both tables. The Benefit Cost Analysis ("BCA") for the project in Section 3.5 will provide all the savings and benefits as well, to provide a holistic, longer-term view of the broader economics of the project.

[4] The discount rate used is BGE's net of tax weighted average cost of capital ("WACC") of 6.42%.

Table 6: Incremental Costs for BESS at Fairhaven Project[5]

$000's	Total Costs (2020-2031)	Total Costs (Present Value)
Capital		
Contractor (Developer)	$6,046	$5,684
Contractor (Other)	$171	$160
Internal Labor	$237	$223
Materials	$35	$33
Interconnection/Permitting	$107	$101
Contingency (@25%)	$1,649	$1,550
Total	$8,243	$7,751
O&M		
Contractor (Developer)	$885	$729
Contractor (Wholesale Operations)	$350	$237
Internal Labor	$43	$29
Materials	$0	$0
Contingency (@25%)	$320	$249
Total	$1,598	$1,244
Grand Total	$9,841	$8,994

Table 7: Revenue Requirement for BESS at Fairhaven Project[5]

$000's	Cumulative Costs	Present Value
Revenue Requirement Costs (15 years)	$17,528	$9,994

As a part of its planning process, BGE includes contingency to account for costs that typically arise in a first-of-its-kind project such as Fairhaven. The cost figures above add a 25% contingency separately, to account for project risks including but not limited to scope, engineering, design, and construction risks and the fact that the contract terms and costs with the leading vendor are still under negotiation and subject to uncertainty. For more information on contingency calculations, please refer to Appendix B.

[5] Figures may not add due to rounding.

3.3 Chesapeake Beach BESS Project

BGE is proposing the Chesapeake Beach project under the "Third-Party Ownership" Model 3. BGE will not own this project. Ameresco has been identified as the proposed vendor for the development of the Chesapeake Beach project. The Chesapeake Beach project will include a single lithium ion BESS that solves a 1.0 MW/1.5 MWh capacity constraint over a 10-year period. In order to account for degradation over the life of the BESS, the project will be oversized to 2.0 MWh at the outset. The design has initially proposed installing the Tesla MegaPack 1001 kW/2023 MWh as the BESS manufacturer and model. Other equipment has to date not been identified.

The primary responsibility of the Chesapeake Beach project will be to provide grid reliability to BGE, by discharging during peak load times during the Winter Event Period (December 1 – March 31 excluding weekends and holidays) upon a communication from BGE to provide additional capacity for the distribution system in the constrained area. BGE will pay for this grid reliability service through a 10-year performance-based contract. When not called upon by BGE, the Chesapeake Beach project will participate in PJM wholesale services markets. The PJM Frequency Regulation D market is expected to be the primary PJM service with energy arbitrage as a tertiary application. More information on contract details are explained in Section 3.3.3 below.

Chesapeake Beach will be located within the identified constrained area and will connect directly to a 13 or 34 kV feeder within BGE's electric distribution system as an FTM project. Four possible locations have been identified by the developer, all of which all have been submitted for pre-application in BGE's Connect the Grid web application[6]. BGE and Ameresco will work together to select a final site for project construction. Set forth below in Table 8 is key information for the Chesapeake Beach project.

[6] Connect the Grid is BGE's web application for customers to apply for connecting generation in BGE's service territory (https://bge.connectthegrid.com/).

Table 8: Key Project Information for Chesapeake Beach Project

Category	Project Information
Required Capacity for Grid Reliability through the 10-year project term	1.0 MW/1.5 MWh
Initial Usable Capacity	1.0 MW/2.0 MWh
Business Model	Model 3: Third-Party Ownership that is Front-of-the-Meter (FTM)
Project Developer	Ameresco is the proposed developer
Energy Storage Technology	Lithium Ion BESS; Proposed Tesla MegaPack (1001 kW 2023 kWh
Primary Application	Grid Reliability
Secondary Application	PJM Wholesale Services (Frequency Regulation D, Energy Arbitrage)
Primary Location(s)	Southern Anne Arundel County and portions of Calvert County; Four possible locations have been identified.
Expected Cost	$2.5 million ($1.9 million in present value) for the 10-year term. For more detail, see section 3.3.5.
Expected Net Savings	On a Net Present Value Basis, Chesapeake Beach will result in a net benefit of $2.5 million. For more detail, see Section 3.5.

3.3.1 Operations Description

BGE seeks discharge capacity during peak load times during the winter to mitigate contingency overload conditions. The grid reliability service is based on BGE sending a series of 15-minute kW signals to the BESS, and then measuring how the BESS performs against that signal. Over the course of a 10-year contract, BGE will have the right (but not the obligation) to initiate an event day ten times during the winter season.

BGE expects to install a site-level BGE-owned RTU to enable communication from BGE's operations systems and the BESS Controller. BGE plans to communicate with the RTU through wireless data. BGE will connect the RTU to the BESS controller through a method to be negotiated with the development vendor. The vendor's initial concept is direct fiber connection.

3.3.2 Other Applications

When not called upon for grid reliability services, the BESS will be deployed in PJM applications. The developer is looking to pursue Frequency Regulation and Energy Arbitrage services. The PJM revenue will be under the vendor's account and they would keep that revenue. However, under a revenue-share construct, BGE would receive a percent of PJM revenue above a certain annual threshold.

3.3.3 Contract Description

For the Chesapeake Beach project, BGE will set up a 10 year pay-for-performance contract for grid reliability services. This contract is expected to include two separate payments for storage capacity and software licensing. The capacity payment compensates the vendor for the development, financing, and operation of the BESS. The software payment compensates the developer for the development, installation, and operation of a software platform that can provide BGE with all the data and application capabilities. For both capacity and software licensing, there will be an upfront payment and a series of annual payments during the 10-year life of the contract.

3.3.4 Proposed Developer Information

Ameresco, the proposed developer for the Chesapeake Beach project, is a leading independent full-service provider of comprehensive energy services for clients globally. Ameresco has developed over $6 billion in energy projects inclusive of approximately 700 MW of clean and renewable generation facilities and 21 MW/46 MWh of battery energy storage systems. With over $1 billion in assets, Ameresco owns and operates many energy projects and provides operations and maintenance support for projects that are client owned.

3.3.5 Cost Information

This section provides incremental cost estimates from two different perspectives. In Table 9 below, the estimates are presented on a cash flow cost basis over a 10-year term, and exclude complexities related to the project's effect on BGE's tax liability**,** amortization and other elements. On this basis, the total incremental cost is expected to be $2.5 million or $1.9 million on a present value basis.[7] The expected contract is an annual performance-based contract expected to be a cumulative total of $1.9 million, excluding contingency. Table 10 below

[7] The discount rate used is BGE's net of tax WACC of 6.42%.

estimates the revenue requirement calculation, which translates to actual costs to the end customer and necessarily includes tax, depreciation and amortization effects over a 15-year timeframe. Indirect costs such as general and administrative are excluded in both tables. The BCA for the project in Section 3.5 will provide all the savings and benefits as well, to provide a holistic, longer-term view of the broader economics of the project.

Table 9: Incremental Costs for Chesapeake Beach Project[8]

$000's	Total Costs (2020-2031)	Total Costs (Present Value)
Capital		
Contractor (Other)	$66	$62
Internal Labor	$0	$0
Materials	$0	$0
Interconnection/Permitting	$200	$188
Contingency (@15%)	$40	$37
Total	$305	$287
O&M		
Contractor (Developer)	$1,923	$1,393
Internal Labor	$7	$4
Materials	$0	$0
Contingency (@15%)	$289	$210
Total	$2,219	$1,607
Grand Total	$2,524	$1,894

Table 10: Revenue Requirement for Chesapeake Beach Project[9]

$000's	Cumulative Costs	Present Value
Revenue Requirement Costs (15 years)	$3,353	$2,037

The cost figures in Table 9 above add a 15% contingency separately, to account for the fact that the contract terms and costs are still under negotiation. The nature of third-party

[8] Figures may not add due to rounding.
[9] Figures may not add due to rounding.

service contracts places more risk on the developer/owner and therefore the contingency is less than the 25% contingency calculated for the Fairhaven project. For more information on contingency calculations, please refer to Appendix B.

3.4 Virtual Power Plant ("VPP") Opportunity

BGE continues to see value in implementing a VPP project, even though the solicitation in the fall of 2019 did not yield a viable VPP solution. Following the April 15, 2020, filing, BGE will investigate the possibility of developing a small VPP project as a potential third project to propose as part of the Commission's energy storage pilot program. If investigation into the VPP option shows it to be implementable, technically effective, and of reasonable cost, BGE would plan to file a VPP project application with the Commission by June 2020. Though details will need to be developed, an early possible design would include hosting a limited number of behind-the-meter residential batteries in the constrained area south of Annapolis in Anne Arundel and Calvert counties. A VPP project would also potentially allow BGE to negotiate down the initial MWh size of its Fairhaven and Chesapeake Beach project proposals, and gradually ramp up VPP MWh capacity at the same time to maintain required capacity. Like the other two BGE projects, the VPP would be provide discharge capacity for the distribution grid during peak periods of load, in addition to other applications.

3.5 Benefit Cost Analysis ("BCA") of BGE Projects

Both the Act and Commission Order Number 89240 note the importance of weighing quantifiable costs against the benefits derived from the implementation of the projects. Accordingly, BGE includes herein a BCA for the two proposed BGE projects. BGE plans to present an economic view that incorporates quantifiable savings metrics such as avoidance of traditional distribution investments as well as unquantifiable metrics such as learnings. The bulk of this section focuses on quantifiable metrics, assumptions, and calculations, although BGE also describes the unquantifiable metrics. Consistent with the December 31, 2019 PC44 Energy Storage Working Group Filing on Value Streams, BGE performed a BCA for the quantifiable value streams, and calculated a present value of benefits versus a present value of costs. The results indicate a net value to customers. The Fairhaven and Chesapeake Beach projects provided present value benefits of \$3.8 million and \$2.5 million, respectively. The benefits and costs for both projects are shown below in Table 11.

As required by the Act, this BCA describes how the project addresses state goals. For environmental and clean energy goals, please review the following benefits: Air Emissions Reduction; Public Health Benefits; NOx Emissions Reductions; Enhancement of Electric Vehicle Charging Infrastructure; and Distributed Generation Hosting Capacity. The support of retail energy markets can be evaluated by reviewing the following benefits: Non-Utility Participation and Third-Party Supplier Participation.

Table 11: Benefit Cost Summary for BGE Fairhaven and Chesapeake Beach Projects[10]

	$000's	BESS at Fairhaven Project		Chesapeake Beach Project	
	Benefit Description	**Present Value**	**Cumulative Benefits**	**Present Value**	**Cumulative Benefits**
Environmental & Public Health					
EPH 01	Air Emissions Reduction	$1.0	$2.5	$0.3	$0.9
EPH 02	Public Health Benefits	$1.0	$2.5	$0.3	$0.9
	Total	$1.9	$5.0	$0.7	$1.9
Distribution Grid Value					
DGV 01	Avoidance of Utility Distribution Costs	$12,631	$29,553	$4,737	$11,082
DGV 02	Optionality	$1,256	$4,939	$271	$1,080
	Total	$13,887	$34,491	$5,007	$12,162
Peak Demand Reductions - Capacity & Energy					
PDR 01	Energy Conservation During Time of Peak	$0	$0	$0	$0
PDR 02	Peak Shaving	$0	$0	$0	$0
	Total	$0	$0	$0	$0
PJM Market Activities					
PJM 01	Black Start	$0	$0	$0	$0
PJM 02	Capacity Price Earnings	$0	$0	$0	$0
PJM 03	Demand Response	$0	$0	$0	$0
PJM 04	Emergency Operations	$0	$0	$0	$0
PJM 05	Energy Arbitrage	$0	$0	$0	$0
PJM 06	Regulation	$2,387	$5,923	$0	$0
PJM 07	Reserves	$0	$0	$0	$0
	Total	$2,387	$5,923	$0	$0
	Total Benefits	**$16,276**	**$40,419**	**$5,008**	**$12,164**
	Total Costs (Revenue Requirements)	**($12,515)**	**($28,284)**	**($2,533)**	**($5,542)**
	Net Benefit / (Cost)	**$3,761**	**$12,135**	**$2,475**	**$6,622**
	Benefit-Cost Ratio	**1.30**		**1.98**	

[10] Figures may not add due to rounding.

3.5.1 Quantifiable Metrics: Global Assumptions

In this section, BGE details the key assumptions that are cross-cutting among the different benefits and costs:

- **Discounting:** BGE utilizes an internal calculation of its current WACC based on the weighted average of the authorized debt and equity rates, with the percent ratio conforming to BGE's authorized capital structure. The current WACC net of tax is 6.42%. All benefits and costs will be discounted to 2020.
- **Charge Discharge Profile:** For the purposes of this analysis, both BGE projects are expected to participate primarily in the PJM Frequency Regulation D ("Reg D") markets when not performing distribution grid services. When the BESS is participating in Reg D, it is typically neutral over any given hour and therefore would not exhibit any load shifting from peak- to off-peak hours. Load shifting therefore would only occur during the expected 10 discharge events annually for distribution grid reliability.
- **Term of the Benefit Value Streams:** All benefit value streams include 33 years of cash flows (2020-2052), to allow for any upfront expenses and 30-year economic lives of the investments.
- **Cash Flow Assumptions:** For the purposes of this analysis, the Avoidance of Utility Distribution Costs, Optionality and Total Costs are calculated on a revenue requirements basis. This therefore incorporates the effects of income tax, depreciation, amortization and other elements that come into play when calculating the revenue requirement impact. Indirect costs such as general and administrative are excluded. All other benefits are included on a straight cash flow basis, and do not include those elements described above.

3.5.2 Quantifiable Metrics: Avoidance of Utility Distribution Upgrades and Total Costs

The method for comparing distribution investment avoidance is distinct from the other value categories in several respects. First, the analysis compares the cost of the proposed projects to a traditional undergrounding investment which has a 30-year useful life. In order to keep the economic alternatives on the same economic timeframe, both the avoided traditional investment and the battery storage approach will be evaluated on a 30-year basis. This results in a 30-year cost timeframe for the proposed BESS projects that includes reinvestments in capacity in years 11 and 16. Table 12 below sets forth key aspects of this calculation:

Table 12: Key Aspects of the Avoided Distribution Investment Calculation

Calculation Parameter	Traditional Approach	Proposed Approach
Project Description	Undergrounding approximately 10 miles of a 34kV feeder	Upgrade portions of a 34kV feeder and install two BESS with combined 3.5 MW/5.5 MWhs in the constrained area
Timeframe of Investments	30-year investment	Upgrades of the 34kV feeder are a 30-year investment. The BESS systems will have an initial 10-year term. The economic analysis assumes reinvestment in MWh capacity in year 11 to account for degradation, and then implementation of a new BESS project in year 16 with 3.5 MW/5.5 MWh capacity requirements for the remaining 15 years.
Forecasted Changes in Cost	Investments made in 2021 and 2022 forecasted from BGE	Storage investments made in year 11 (2032) and year 16 (2037) will be 50% and 59% less expensive on a per MWh basis, per Bloomberg New Energy Finance's forecast.[11]

[11] Bloomberg New Energy Finance, Energy Storage System Costs Survey 2019, October 2019.

The quantified savings for Avoided Utility Distribution as presented in Table 12 above are therefore the cost of the traditional approach after subtracting the upgrades to the 34kV feeder investments in the BESS approach.

As a consequence of the methodology described above, the Total Cost figures will differ from the project costs shown in Sections 3.2.5 and 3.3.5 for Fairhaven and Chesapeake Beach, respectively, which track direct costs incurred over the 10 and 15-year terms of the project that is proposed for approval.

3.5.3 Quantifiable Metrics: Optionality

Storage investments are unique in that they are modular. Modularity allows the investor to build the systems via an "on demand" basis, and potentially break up investments along multiple time increments, as more information is known. This reduces the likelihood that these assets will become stranded or provide reduced value. For the Fairhaven and Chesapeake Beach projects, a key investment decision is being made after 10 years where BGE must decide to reinvest in 2032 to maintain guaranteed capacity. In year 16, BGE will also decide to pursue the installation of a new 3.5 MW/5.5 MWh BESS to continue to provide that long-term required capacity. The Total Cost calculations in the BCA (described in Section 3.5 above) presume that the year 11 and 16 investments occur.

However, there is a likelihood that load forecasts will have changed by that point and the additional investments may no longer be needed. Therefore, the Optionality benefit first calculates the reduction in Total Cost of the battery approach if the investments in both years 11 and 16 are not needed, and then secondly multiplies that savings by the probability of that scenario occurring. Leveraging the assumptions laid out in New York's Energy Storage Roadmap[12]

[12] New York Storage Roadmap, June 2018, pgs. 42-43, available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b2A1BFBC9-85B4-4DAE-BCAE-164B21B0DC3D%7d.

and as was described in the December 31, 2019 PC44 Energy Storage Working Group filing, BGE assumes a 50% probability that investments in year 11 and 16 are not required.[13]

In this analysis, BGE does not attempt to quantify the financial benefit in the ability to move the battery to another constrained location, if there is a greater need elsewhere. However, that is another tangible benefit that could be explored in future projects and filings.

3.5.4 Quantifiable Metrics: Other Category-Specific Assumptions

In Table 13 below, BGE provides some calculation details for other quantifiable benefits. As noted in Section 3.5.1 above, the projects are not expected to load shift between peak and off-peak periods except for the approximately 10 times per year when grid reliability is needed, which does place limits on the benefits for several value streams.

[13] The year 11 and 16 investments would not be needed in several scenarios. For instance, load forecasts for the constrained area could change or decrease versus current expectation. Also, natural gas service could be extended to that area of BGE's territory where there is no natural gas service, alleviating some of the winter peak load.

Table 13: Quantifiable Benefit Assumptions

Benefit	Methodology
Air Emissions Reduction Value	Consistent with the December 31, 2019 Storage Working Group Filing
Values for Public Health Benefits from Load Shifting	Consistent with the December 31, 2019 Storage Working Group Filing
Avoided Distribution System Upgrades	See Section 3.5.2
Optionality	See Section 3.5.3
Energy Conservation During Time of Peak	Consistent with the December 31, 2019 PC44 Storage Working Group Filing
Peak Shaving (Reduction of Zonal Capacity Obligation/Transmission Obligation)	Consistent with the December 31, 2019 PC44 Storage Working Group Filing
PJM Market Activities	When not engaged in grid reliability services, BGE assumes for the purposes of this analysis that the Fairhaven project participates in the PJM Frequency Regulation D market. The forecast of PJM revenue is based on analysis provided by Customized Energy Solutions (CES). For the purposes of this analysis, no revenues are forecasted for the Chesapeake Beach project.

3.5.5 Unquantified Metrics

In this section, BGE provides qualitative assessments of benefits that were outlined in the December 31, 2019 PC44 Energy Storage Working Group filing. Note that although these value streams do not have dollars associated with them, that should not discount the importance and value that they drive for Maryland electric customers. For more information on these value streams, please refer to Maillog # 229020, the Submission of the PC44 Energy Storage Working

Group on December 31, 2019, in Case No. 9619. Please refer to Table 14 below for a summary of the unquantifiable benefits of both the Fairhaven and Chesapeake Beach projects.

Table 14: Unquantifiable Benefits of BGE's Fairhaven and Chesapeake Beach Projects

Benefit	**Assessment**
Learnings	The projects will provide BGE with the following key learnings: (a) greater experience in dealing with battery storage technologies and integrating those technologies into BGE's control systems; (b) expertise in executing third party contracts for grid reliability and PJM applications; and (c) creating regulatory templates that allow third-party owned technologies to compete on an even playing field with BGE-owned investments from a utility financial return perspective.
NOx Emissions Reductions	Both projects will be shifting energy from high emissions to low emissions during the days BGE calls upon those assets for grid reliability (approximately 10 days a year). Based on the methodology outlined in the December 31, 2019, Value Streams filing, a total 14.4 lbs. and 5.4 lbs. of NOx would be avoided per year for Fairhaven and Chesapeake respectively.
Land Use / Avoidance of Impacts	The projects would avoid the development associated with undergrounding approximately 10 miles of electric cable.
Reliability and Resilience	The constrained area identified in Section 3.1 has been subject to customer load sheds when this contingency occurred in the past. These projects are expected to improve reliability versus the current state, though the direct benefit is difficult to quantify. These projects are not expected to be incorporated into any microgrids, but that is something that may be explored later. The Fairhaven BESS may be incorporated into customer auto-restoration plans, but that is not anticipated initially.
Power Quality / Grid Operational Flexibility	The Fairhaven project may be able to provide additional services to improve quality of electric service, though its predominate service will be to provide capacity to avoid post-contingency overload. Storage is a flexible electric asset that indeed will give BGE options if there is a need to redeploy elsewhere or dispatch for a different service.
Distributed Generation Hosting Capacity	Both BGE energy storage projects are not currently expected to improve hosting capacity for distributed generation, but that

	could be a future application if the constrained area requires more capacity for distributed generation.
Enhancement of Electric Vehicle Charging Infrastructure	BGE is investing in electric vehicle infrastructure across its territory as part of the EVsmart program. Both BGE energy storage projects currently do not enhance EV infrastructure, but the EV market and storage markets are closely aligned. Given the possibility of vehicle to grid applications in the future, BGE will continue to investigate opportunities to engage with EVs for grid reliability services.
Economic Development	These projects will help Maryland begin to develop the nascent local storage market and help solar developers incorporate storage, providing a potential positive effect on the Maryland economy.
Non-Utility Participation	This RFP solicitation reached 87 vendors, many of whom have never engaged in a contract with BGE or Exelon. This has helped BGE foster its relationship with the vendor community.
Third Party Supplier Participation	This project will help advance the discussion of the role of third parties in the operation of the grid, as part of a broader movement towards "Non-wires alternatives."

4.0 Delmarva Power & Light Company Projects

Delmarva Power's engineering team identified five potential energy storage site applications. Initially identified potential storage projects included: 1) storage to provide a reverse power buffer for Church Substation located at Church T3 on feeder MD 2232 to enhance distributed energy resources ("DER") hosting capacity; 2) storage to provide a reverse power buffer for Pocomoke Substation to enhance DER hosting capacity at Pocomoke T3 on feeder MD 0433; 3) storage to increase the capacity of the Centreville distributed automation ("DA") scheme for 3,025 customers fed from the Steele Substation; 4) the recommended Elk Neck residential storage project described below; and 5) the recommended Ocean City project described below. The projects designed to increase DER hosting capacity are not recommended at this time because of uncertainty regarding the number and size of DER projects that would be installed. as a result of the improvement. Due the absence of any significant forecasted load growth in the Delmarva Power Maryland service territory, no project provided opportunities to defer any significant construction of distribution or transmission capital upgrades.

4.0.1 Communications

Delmarva Power is undertaking a community outreach and engagement initiative to inform local public officials, customers, and the media of the benefits of energy storage technology and share information regarding the purposes of the Maryland Energy Storage Pilot Program. Delmarva Power is committed to working with local public officials and community leaders to coordinate outreach within each community. The initiative will keep members of the community informed throughout the process and provide timely updates as key milestones are reached. The company has developed talking points and collateral materials to support this outreach. Initial steps were taken prior to this filing to introduce the proposed projects to key stakeholders and answer questions. Following the filing, and as the projects move forward, broader outreach to media and community members will be undertaken to provide a summary of the benefits of the proposed projects in the Ocean City and Elk Neck communities.

4.0.2 Vendor Bids

Delmarva Power jointly issued an RFI with the other Joint Exelon Utilities as mentioned previously during October 2019. The RFI was sent to 67 storage vendors. The RFI stated the general size of requested storage projects, the alternative business models, and the timing of required installations. The RFI did not state a preference for a specific storage technology or a preferred business model. As noted earlier, six vendors responded to the RFI and provided their recommendations and capabilities.

Delmarva Power prepared and issued an RFP on January 17, 2020, that was included as part of an RFP solicitation package with the other Joint Exelon Utilities. Vendor responses were due by February 19, 2020. Similar to the other Joint Exelon Utilities, the Delmarva Power RFP sought a full requirement contract for BESS storage, including the battery, installation, and maintenance over a 10-year period. The RFP provided project site information, the planned use cases for the BESS at each site, and the detailed technical requirements of the utility. As noted earlier, the RFP was issued to 87 potential vendors. Eleven vendors responded to the Delmarva Power RFP and submitted 17 different proposals. Four vendors submitted 4 bid proposals for the Elk Neck Project and 9 vendors submitted 16 different proposals for the Ocean City Project. One vendor submitted a software proposal that was not responsive to the RFP request.

Table 15 : Delmarva Power Bid Proposal Summary

Business Model	Elk Neck	Ocean City	Total
Utility Owned/Utility Operated		7	**7**
Utility Owned/Third Party Operated		5	**5**
Third Party Owned/Third Party Operated		3	**3**
Virtual Power Plant	4	1	**5**
Software Platform	1	1	**2**
Total	**5**	**17**	**22**

4.0.3 Vendor Selection

Delmarva Power reviewed the technical components of each proposal, including the vendor's experience and the vendor's proposed business model. As discussed in the PC44 Energy Storage Working Group filing of August 1, 2019, final vendor contracts will be established for a

10-year period after the Commission approves each proposed project. Contract preparations are underway with each selected vendor. The timing of Commission approval will determine when project implementation will begin.

4.1 Elk Neck Virtual Power Plant Storage Proposal

Delmarva Power narrowed the list of potential energy storage projects to two based on the expected value (quantified and unquantified) of each application. This resulted in the selection of a storage opportunity at Elk Neck State Park in Cecil County, Maryland to enhance the reliability of service for an isolated residential community of 330 homes[14] located on a peninsula in the Chesapeake Bay. The residences at Elk Neck are served by a heavily forested four-mile long overhead and underground distribution feeder along Turkey Point Road that is partially located within Elk Neck State Park. The selected storage size at this location is recommended to be 0.5 MW capacity with 1.5 MWh of energy over the 10-year period. A summary of the project proposal is contained in

[14] These residential customers are located on Delmarva Power feeder Cecil MD 3487 downstream of recloser 37123/34934. Note that 270 customers are located south of Elk Neck State Park and the remaining customers are located north of the park.

Table **16**.

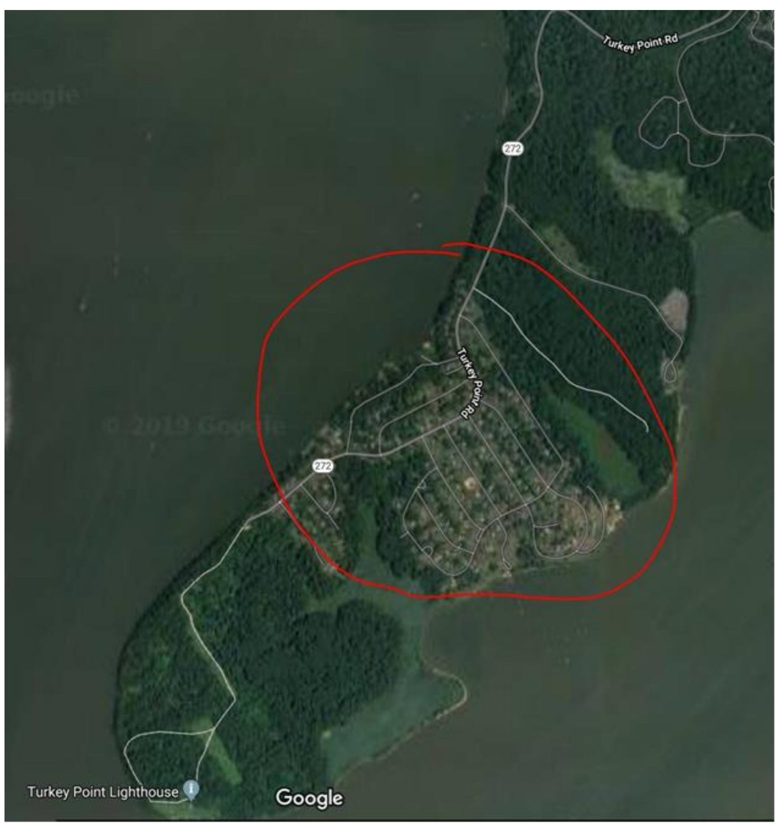
Table 16: Elk Neck Project Proposal Summary

Category	Project Information
Required Capacity for Grid Reliability through the 10-year project term	0.5 MW/1.5 MWh
Initial Usable Capacity	0.55 MW/2.2 MWh
Business Model	Model 4: Virtual Power Plant (VPP) - BTM
Project Developer	Sunverge Energy, Inc.
Energy Storage Technology	LG Electronics 5kW/19.6 kWh
Primary Application	Grid Reliability & Backup Power
Secondary Application	DER-Integration/Possible PJM Market Participation
Primary Location(s)	Elk Neck, Cecil County, MD
Expected Cost	$4.0 million ($3.5 million in present value) for 10-year term. $6.3 million ($4.0 million in present value) on a revenue requirement basis (15-year term).
Expected Benefits	$2.0 million ($1.2 million in present value) over a 15-year term and significant unquantified benefits.

It was expected that the most applicable storage business model would be a third-party owned BTM residential batteries that would be aggregated to support the electric grid – providing an example of a VPP business model. This model is recommended for Elk Neck for the following reasons: 1) to provide reliability support for individual residences; 2) to provide unique pilot program for all Joint Exelon Utilities that provides learnings from an aggregated residential behind-the-meter storage VPP project; 3) to develop potential PJM market opportunities for VPP projects; 4) to examine the practicalities of the use of behind-the-meter residential batteries; and 5) to explore the ability of residential batteries to help accommodate the increasing quantity of distributed generation. While other storage models are possible at this location, they would require modifications to Delmarva Power's electric distribution system.

The installed storage is expected to provide aggregated peak shaving capability to Delmarva Power during periods of high load or load reduction/load injection capability during emergency grid conditions in the Elk Neck area. The aggregated batteries can also provide voltage or volt-ampere reactive ("VAR") support to the grid when needed. Participating customers who receive batteries can realize various benefits that include a limited period of back-up power for essential residential loads during grid outages, an opportunity to store electricity from installed photovoltaic arrays for use at a later time, an opportunity to reduce electricity use from the grid during Peak Energy Savings Credit events (Delmarva Power's residential dynamic pricing program), and an opportunity to reduce grid supplied energy use in response to a Delmarva Power or third-party supplier time-of-use rates. Delmarva Power and Sunverge Energy, Inc. ("Sunverge"), the selected vendor, have agreed to work with PJM to determine whether a method for a VPP (VPP) energy storage model can be developed to participate in the PJM wholesale market to derive a wholesale electricity market revenue stream.

Figure 2: Elk Neck Site Location



4.1.1 Project Vendor

Delmarva Power's selected vendor for the Elk Neck project is Sunverge. Sunverge offers an intelligent residential energy storage DER control and aggregation software platform compatible with multiple energy storage hardware options. Sunverge's real-time control and aggregation platform is deployed in a variety of locations and electricity markets. The Sunverge platform can be used to integrate and manage energy storage, photovoltaics, smart home devices such as thermostats and hot water heaters, and EV chargers. Sunverge plans to deploy Sunverge Infinity + LG Electronics 5 kW/19.6 kWh energy storage systems BTM at 110 residential customer homes for the 0.5 MW/1.5 MWh Elk Neck project. The planned initial size of the project is 0.55 MW and 2.2 MWh to account for customer attrition and battery degradation over a 10-year period.

Sunverge provides a cloud-based dynamic distributed generation aggregation and control platform to aggregate the installed batteries as a VPP. The platform will allow Delmarva Power to control, manage, and orchestrate the use of the batteries for peak shaving, grid support, and potentially for PJM market purposes. In effect, the platform will act as a "nanogrid" controller for the installed residential batteries for Delmarva Power.

Sunverge has relevant experience through the following projects.

- Sacramento Municipal Utility District Project – Sunverge installed smart thermostats and smart storage systems. Sunverge integrated the installed equipment to reduce electric loads. This pilot program occurred during the 2013 to 2014 period.
- Tennessee Valley Authority Project – Sunverge installed energy storage at 168 homes and businesses to provide 1 MW of load reduction capability. The storage installation lowers customer demand charges on electric bills and provides reliable backup power. The Sunverge aggregation system permits energy delivery to the grid as a single VPP at the point of load, reducing line losses, and distribution upgrades.
- Powerhouse Project – Toronto, Ontario VPP for a municipal utility. This project includes distributed solar photovoltaic arrays. Each residential participant has a 11.4 kWh Sunverge storage unit that is aggregated into a VPP model.

- Sunverge is currently working on a residential BTM storage project with the New York ISO for day-ahead pricing to respond to dynamic energy and demand tariffs. This is part of the New York Public Service Commission's effort to establish more cost-reflective, transparent rates that can enhance the value of distributed energy resources and improve distribution system efficiency.

4.1.2 Project Specifics

Sunverge will recruit residential participation in the VPP at Elk Neck and install BTM, grid-aware residential energy storage systems and integrate the batteries into a VPP. The 110 residential customers who are recruited into the program will receive free installation of a battery and its use during periods when battery is not being used for peak shaving purposes, emergency grid conditions, or (if feasible) for PJM market purposes. The primary use of the battery for residential participants will be to avoid outages for critical loads. Market research will be conducted after the conclusion of the pilot program to determine what pilot participants would be willing to pay for the battery on a monthly basis. Any required electrical panel upgrades will be the responsibility of the homeowner. The batteries are expected to have a minimum life of 15 years. At the end of the 10-year contract period, ownership of the batteries will transfer from Sunverge to participating customers. If requested, Sunverge will assist participating customers in locating a qualified, appropriately certified service provider, to dispose of the battery if a participating customer elects to cease using the battery. After ownership transfers to the participating customer, responsibility for the removal and proper disposal of the system will be the responsibility of the customer.

Customer recruitment efforts will be led by CLEAResult. CLEAResult currently manages the lighting, appliance, and HVAC EmPOWER Maryland programs for Delmarva Power. If recruitment efforts are lagging after six months, Delmarva Power will expand the eligible number of residential customers beyond Elk Neck, but in the same geographic area, to reach the target of 110 residential participants. If the Elk Neck Project is approved by the Commission, Delmarva Power will enter into a 10-year contract for the VPP Project.

4.1.3 Project Costs

The incremental 10-year project costs for the Elk Neck VPP Project are shown in Table 17 below. Additionally, since the batteries are expected to operate for a 15-year period, the revenue requirements over 15 years are shown in Table 18 below (15-year costs are included in this table). A contingency of 20% of project costs is included due to the risk and uncertainties related to the implementation of a new residential BTM VPP system across multiple homes. For more information on how the Joint Exelon Utilities estimate the appropriate contingency, please see Appendix B.

Table 17: Elk Neck 10 Year Incremental Project Costs ($000's) [15]

	Deployment Phase Inception - 12.31.21	Operational Phase 1.1.22 - 12.31.31	Total Costs
Capital			
Contractor (Developer)	$0	$0	$0
Contractor (Other)	$0	$0	$0
Internal Labor	$0	$0	$0
Materials	$0	$0	$0
Interconnection/Permitting	$0	$0	$0
Contingency (@20%)	$0	$0	$0
Total	$0	$0	$0
O&M			
Contractor (Developer)	$2,074	$1,068	$3,142
Contractor (Wholesale Operations)	$0	$161	$161
Materials	$0	$0	$0
Interconnection/Permitting	$0	$0	$0
Contingency (@20%)	$415	$246	$661
Total	$2,489	$1,475	$3,964
Grand Total	**$2,489**	**$1,475**	**$3,964**
Present Value of Total Costs			**$3,525**

[15] Excludes non-incremental labor and overhead costs. Figures may not add due to rounding.

Table 18: Elk Neck Project 15 Year Revenue Requirements ($000's) [16]

	Present Value Inception - 12.31.36	Cumulative Inception - 12.31.36
Capital		
Contractor (Developer)	$0	$0
Contractor (Other)	$0	$0
Internal Labor	$0	$0
Materials	$0	$0
Interconnection/Permitting	$0	$0
Contingency (@20%)	$0	$0
Total	$0	$0
O&M		
Contractor (Developer)	$3,165	$5,001
Contractor (Wholesale Operations)	$154	$271
Materials	$0	$0
Interconnection/Permitting	$0	$0
Contingency (@20%)	$664	$1,054
Total	$3,983	$6,326
Grand Total	**$3,983**	**$6,326**

4.1.4 Project Benefits

The quantified project benefits over the expected 15-year life of the batteries are shown in Table 19 below and the unquantifiable benefits are shown in Table 20 below. Delmarva Power has listed each of the benefits/value streams identified in the PC44 Energy Storage Working Group December 31, 2019 report, and where possible estimated a benefit. The quantified benefits that have values for the Elk Neck project are briefly summarized below. Please refer to the PC44 Energy Storage Working Group Filing of December 31, 2019, for a description of the basis for the calculated value.

EPH 01 Air Emissions Reductions – Estimated dollar value of the net tons of greenhouse gas emissions reductions based on an assumption of 84 pounds per MWh of load shifted

[16] Figures may not add due to rounding.

from an on-peak hour to an off-peak hour. It was assumed that the residential batteries will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Delmarva Power's request. Discharges will take place during other days, but the timing of those events is uncertain.

EPJ 02 Public Health Benefits – Estimated dollar value of the public health benefits of shifting energy use from an on-peak hour to an off-peak hour in Maryland. The new U. S. Environmental Protection Agency ("EPA") public health quantification tool assigns a value of $1.30 for each MWh of load shifted from an on-peak hour to an off-peak hour in Maryland. The EPA tool financially quantifies the health benefits value of particulate reduction, which is distinct for the other environmental benefits that are included. It was assumed that the residential batteries will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Delmarva Power's request. Discharges will take place during other days, but the timing of those events is uncertain.

PDR 01 Energy Conservation during Time of Peak – By reducing the need to supply customers grid-sourced energy during periods of peak demand, the utilities reduce the cost of delivering energy to customers during periods of high demand. It was assumed that the residential batteries will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Delmarva Power's request.

PDR 02 Peak Shaving (Zonal Capacity Obligation) – By reducing loads at the time of peak, the capacity obligation in the Maryland portion of the Delmarva Power Zone is reduced. It was assumed that peak load discharges occur during the top 5 PJM Peak Load Contribution ("PLC") hours each year.

PJM 05 Energy Arbitrage – By exporting energy from the aggregated residential battery resource, the Elk Neck project may be able to benefit by selling energy into the market during high priced periods and consuming it during a low-priced period. At this time the rules regarding aggregated residential BTM battery storage in the wholesale electricity market are not resolved. As noted previously, Delmarva Power will work with PJM to determine the feasibility of this project to participate in the electric wholesale market. For this estimate it was assumed that VPP participation in the wholesale market is possible beginning in 2024 and that there is an energy arbitrage opportunity. The forecast of PJM revenue is based on analysis provided by CES.

PJM 06 Regulation – BESSs that are located in FTM applications are permitted to participate in the PJM regulation market. However, at this time the ability of aggregated residential BTM battery storage to participate in the wholesale markets are not resolved. As noted above, Delmarva Power will work with PJM to determine the feasibility of this project to participate in the electric wholesale market. For this estimate it was assumed that VPP participation in the wholesale market is possible beginning in 2024. The forecast of PJM revenue is based on analysis provided by CES.

Table 19: Elk Neck 15 Year Project Benefits ($000's)[17]

Benefit Identifier	Benefit Description	Present Value (PV) at 12.31.21	Cumulative Benefits
Enviornmental & Public Health			
EPH 01	Air Emissions Reduction	$0.2	$0.3
EPH 02	Public Health Benefits	$0.2	$0.3
	Total	$0.4	$0.6
Distribution Grid Value			
DGV 01	Deferral/Avoidance of Utility Distribution Costs	$0	$0
DGV 02	Optionality	$0	$0
	Total	$0	$0
Peak Demand Reductions - Capacity & Energy			
PDR 01	Energy Conservation During Time of Peak	$2	$3
PDR 02	Peak Shaving (Zonal Capacity/Transmission Obligation)	$563	$923
	Total	$565	$927
PJM Market Activities			
PJM 01	Black Start	$0	$0
PJM 02	Capacity Price Earnings	$0	$0
PJM 03	Demand Response	$0	$0
PJM 04	Emergency Operations	$0	$0
PJM 05	Energy Arbitrage	$85	$150
PJM 06	Regulation	$528	$930
PJM 07	Reserves	$0	$0
	Total	$614	$1,080
	Total Benefits	**$1,179**	**$2,007**
	Total Costs (Revenue Requirements)	**$3,983**	**$6,326**
	Benefit-Cost Ratio	**0.30**	

The unquantified benefit value streams for the Elk Neck project are shown in Table 20 below. These benefits include the following:

[17] Figures may not add due to rounding.

- Avoided residential outages in an isolated community with greater outage vulnerability due to the unique geography of the area. This benefit is included in the unquantified benefit section because of the difficulty of estimating the number of minutes of avoided outages.
- NOx emissions reductions from both the avoided use of backup residential fossil fueled generators during outage events, but also large power plant emissions that are avoided by use of the batteries during peak load periods.
- Noise avoidance by avoidance of the use of backup residential fossil fueled generators during outage events. (Benefit not identified in the PC44 Energy Storage Working Group Report of December 31, 2019).
- Improved land use by lessening the need for additional distribution, transmission, and generation equipment to meet higher peak loads and potential ability to avoid distribution line upgrades through Elk Neck State Park.
- Distribution hosting capacity improvement by permitting residential customers with batteries and solar photovoltaic arrays to store energy for use during periods when the sun is not shining. This reduces the export of solar photovoltaic energy on the distribution system, helping to increase Delmarva Power's ability to host additional solar photovoltaic arrays. Additionally, availability of volt/var support could help to increase distribution system solar photovoltaic array hosting capacity.
- EV transportation support by providing a source of energy for EV charging during grid outages and reducing the peak load impact of EV charging.
- Economic development by providing local Maryland jobs for marketing, installation, and maintenance of batteries. Individuals working out of home will be able to continue to work during outage events.
- Learnings by providing a Maryland pilot residential VPP business model that will explore the practicalities of aggregating residential BTM batteries for grid support purposes and potential integration into the PJM wholesale market. Additional learnings include: Maryland customer receptivity to BTM batteries; information

on the operation and maintenance of residential BTM batteries; and exploration of the use of batteries to support the increasing penetration of photovoltaic arrays.

- Non-utility participation – by allowing a third-party entity to develop a non-wires alternative to distribution system upgrades.
- Grid services to support operational flexibility for the delivery of electricity – the availability of an aggregation of residential BTM batteries provides another tool to utility distribution control centers to better manage the distribution of electricity. This is similar to Delmarva Power's tool of aggregated residential direct load control for residential air conditioner compressor cycling, the Energy Wise Rewards Program.
- Resilience – available residential batteries during wide-scale outages could permit the more efficient dispatch of utility crews if customers with critical health needs have battery systems. This could reduce the length of major outages and lessen the macroeconomic impact of those events in the region.
- Other societal benefits – support for residential customers on the Maryland Eastern Shore who live in an isolated community on a peninsula in the Chesapeake Bay.
- Third party supplier participation – all customers can participate regardless of their selected generation supplier, and the availability of batteries will encourage both suppliers and residential customers to embrace innovative time differentiated rates.
- Customer willingness-to-pay – by offering an opportunity to directly explore through market research the willingness/interest of residential customers to pay for BTM battery systems.

Table 20: Elk Neck Unquantified Benefits

No.	Value Streams	Project Applicability	Comments
1	NOx Emissions Reductions	●	Reduced PJM Generator Air Emissions and Use of Backup Generators
2	Noise Avoidance	●	Avoided Use of Residential Backup Generators
3	Land Use	●	Avoided Disturbance of Elk Neck State Park for Feeder Improvements and Distribution System Upgrades
4	Distributed Generation Hosting Capacity	●	Support for PV Arrays on Customer Homes
5	Electric Vehicle Transportation	●	Reduction in Demand during Charging and Support for Charging during Outages
6	Economic Development	●	Installation and Maintenance Jobs in Elk Neck Area/Reduced Outages for Individuals Working from Home
7	Learnings	●	Unique Maryland Exelon Utility Business Model -- Residential Virtual Power Plant
8	Non-Utility Participation	●	Third Party Ownership and Aggregated Operation
9	Offshore Wind		
10	Grid Service -- Operational Flexibility Related to the Delivery of Electricity	●	Available for Delmarva Power use -- Peak Shaving and Emergency Grid Conditions
11	Resilience	●	More Flexible Crew Restoration Work during Large-Scale Outages -- Reducing Length of Outages
12	Other Societal Benefits	●	Support for Eastern Shore Residential Customers
13	Third Party Supplier Participation	●	Customer Eligibility Regardless of Supplier + Support for Innovative Rate Design
14	Customer Willingness-to-Pay	●	Market Research to Quantify Customer Willingness-to Pay for Storage

4.1.5 Conclusion

While the Elk Neck project is not expected to have quantifiable benefits exceeding costs over the expected 15-year life of the BESS project, when combined with the unquantified benefits, this project is a critical part of exploring the opportunities for residential battery storage in Maryland. This will provide significant learnings for State policy makers regarding the aggregation, integration, and use of BTM batteries for Maryland customers, policymakers, and utilities. This pilot project is a critical component of the Maryland energy storage pilot program. The increasing use of solar photovoltaic arrays combined with declining battery prices underscores the importance of the Elk Neck project to Maryland policymakers, residential electricity consumers, and electricity suppliers. The use of BTM batteries will increase as prices decline and photovoltaics penetration expands.

4.2 Ocean City Storage Proposal

The second recommended pilot storage opportunity for Delmarva Power is located at Ocean City, Maryland, a beach community located on a barrier island in the Atlantic Ocean. The barrier island is subject to increasing storm risk and possible distribution system outages due to climate change. Ocean City is a significant area of economic activity for Maryland due to the number of annual beach visitors to this location. The selected storage size at this location is recommended to be a 1 MW BESS with 3 MWh of energy storage in FTM. The installed BESS would be located on utility-owned property on the bay side of the 10,000 block of Coastal Hwy in Ocean City. The location of the BESS site is north of the Worcester County Public Library at 100th Street. The selected business model for the site is a utility -owned and operated BESS. This selection was made because of the following factors: 1) selection of a third party owned VPP model at Elk Neck; 2) utility ownership of the Ocean City site location; 3) the sensitivity of the community to Delmarva Power installation and operation of electric distribution equipment at this location; 4) the ability to test utility operational management of a BESS; and 5) it provides Pepco and Delmarva Power an opportunity to test a unique storage business model that differs from the Companies' other project proposals.

The BESS is expected to provide peak shaving capability in this capacity constrained area to Delmarva Power during periods of high winter or summer load and during emergency grid conditions at Ocean City. Operation of the BESS during high load periods will reduce the thermal stress on distribution equipment, thereby extending the equipment's service life. High localized PJM Locational Marginal Prices of energy will be lowered during high demand periods. Availability of the BESS during outage events may reduce the length of time for outage restoration in the area by allowing the Automatic Sectionalizing and Restoration[18] ("ASR") scheme to operate at higher customer loading levels than the existing level. Reliability will be improved by supporting an expansion of the existing Ocean Bay - Maridel ASR and enhancing the operation of the existing ASR scheme during high load conditions on nearby feeders Ocean Bay MD0404 (2,866 customers), Ocean Bay 0405 (2,422 customers), and Ocean Bay MD0406 (2,122 customers). A future expansion of this ASR scheme is planned to occur prior to BESS installation

[18] ASR consists of automated switches, controllers, smart sensors, and substation electronic relays that are connected to electric distribution system, allowing for continuous visibility and remote control of the system. These devices work together to identify faults, automatically isolate identified problem areas and reconfigure the controlled feeders. This reduces the number and length of electric system outages and minimizes the impact to customers.

and will include 138th Street Feeder MD0432 (3,591 customers). Collectively the ASR feeders where reliability will be improved serve more than 11,000 residential and business customers. At other times, the BESS will be used to participate in the PJM wholesale market and is expected to provide ancillary market earnings opportunities that will help to partially offset project costs. Delmarva Power is exploring the possibility of improving the resiliency of an adjacent publicly owned library at the site by connecting the BESS in a manner that would directly serve the library during outage events. This could provide several days of electricity to the library depending on connected loads, which could potentially serve as an emergency site for the community. As summary of the project proposal is shown in Table 21 below.

Table 21: Summary of Ocean City Project Proposal

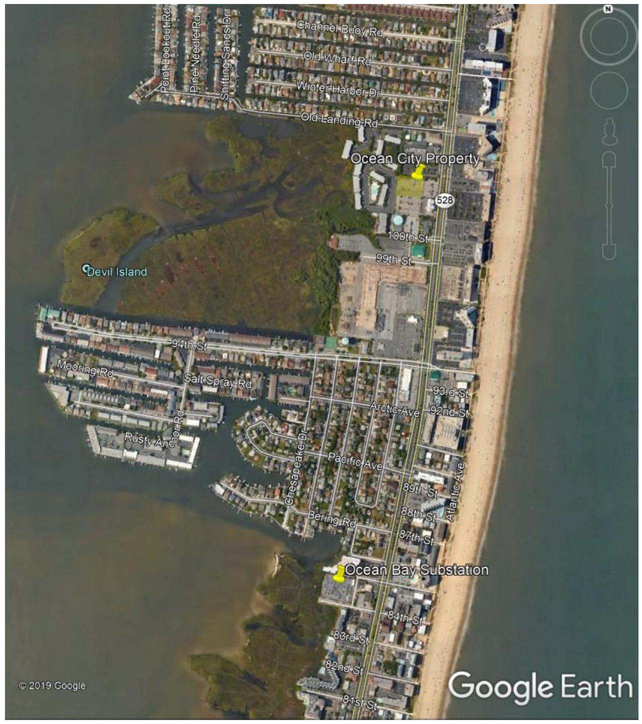
Category	Project Information
Required Capacity for Grid Reliability through the 10-year project term	1.0 MW/3.0 MWh
Initial Usable Capacity	1.0 MW/3.6 MWh
Business Model	Model 1: Utility Owned & Operated – FTM
Project Developer	MESA Veterans Power
Energy Storage Technology	Nickle Manganese Cobalt Lithium Ion
Primary Application	Peak Shaving, Grid Reliability, Resiliency
Secondary Application	PJM Wholesale Services (Frequency Regulation D, Energy Arbitrage)
Primary Location(s)	Ocean City, MD
Expected Cost	$5.9 million ($5.3 million in present value) for 10-year term. $9.5 million ($5.8 million in present value) on a revenue requirement basis (15-year term).
Expected Benefits	$4.3 million ($2.6 million in present value) over a 15-year and Significant Unquantified Benefits. For more detail, see Section 4.2.4 below.

Figure 3 and

Figure **4** below shows the site where the BESS will be located.

Figure 3: Ocean City Project Energy Storage Site

Figure 4: Ocean City Project Area



4.2.1 Project Vendor

Delmarva Power's selected vendor for the installation and ongoing maintenance of the 1 MW/3 MWh utility-owned BESS project is Mesa Veterans Power, LLC ("Mesa"). The BESS will be owned and operated by Delmarva Power under the selected business model for this project and will be connected to the distribution system in FTM. The installed BESS size will be 1 MW with 3.63 MWh of energy to meet the energy requirement of 3 MWh over the 10-year contract period.

4.2.2 Project Specifics

Mesa's plan includes delivery of one BESS system comprised of two 500 kW rated EPC Power "CAB500" PCS Inverters for a total power capacity of 1 MW. The BESS System is comprised of Nickel-Manganese Cobalt (NMC) chemistry Lithium Ion batteries configured in 33 each, 0.11 MWh Mark 1 BESS stacks from Kore Power, for a total energy capability of 3.630 MWh. The 1 MW Inverter system is supplied by two 500 kW AC inverter modules connected to BESS rack strings on the DC side. The Mesa energy storage system includes: the batteries; the supply and integration of two 500kw grid tie inverters in outdoor-rated enclosures; equipment enclosures; and environmental, operational, monitoring, and safety controls for the BESS system. The BESS

System and DC connections will be in an enclosure designed to meet National Fire Protection Association 855 and Underwriters Laboratories 9540 requirements for system safety and hazard mitigation. Enclosure features include external access to the batteries through fire-rated doors and compartmentalization of batteries in 250 kWh BESS units, each protected by 2-hour fire rated compartments, with autonomous HVAC, fire suppression, and Fire/Smoke/Off-Gas detection.

Mesa engineering and construction subcontractors will provide grid connection to the Delmarva Power distribution feeder. Site engineering, construction, and BESS integration to the distribution circuit will be conducted by Utility Lines Construction Services ("ULCS"), from their offices in Dundalk, Maryland, and American Engineering & Testing as a sub-supplier and partner to Mesa. Commissioning, testing, and training on site will be completed in a mutual effort by Mesa, ULCS, and Kore Power under the oversight of Mesa's Project Manager.

The round-trip efficiency of the Mesa installed BESS is 93%-98% measured at the AC side of the inverters. This excludes efficiency losses from the transformer and switchgear, which are less than 3%. Therefore, total roundtrip efficiency is greater than 90%.

The use case for the installed BESS includes the following:

- Utility controlled operations during emergency grid conditions;
- Utility controlled peak shaving;
- PJM market use;
- Support for local customer loads; and
- Engineered to support the future integration of renewable energy resources.

If the Ocean City Project is approved, Delmarva Power will enter into a 10-year contract with MESA for the installation and maintenance of the BESS.

4.2.3 Project Costs

The incremental 10-year project costs for the Ocean City project are shown below in Table 22. Additionally, since the batteries are expected to operate for a 15-year period, the revenue requirements are shown below in Table 23 for that period. (This table includes incremental costs for a 15-year period.) A contingency of 25% has been included due to the risks and uncertainties of the installation of a new non-wires alternative distribution system technology. For more information on how the Joint Exelon Utilities determine contingency, please see Appendix B.

Table 22: Ocean City 10 Year Project Cost

	Deployment Phase Inception - 12.31.21	Operational Phase 1.1.22 - 12.31.31	Total Costs
Capital			
Contractor (Developer)	$2,941	$0	$2,941
Contractor (Other)	$0	$0	$0
Internal Labor	$0	$0	$0
Materials	$170	$0	$170
Interconnection/Permitting	$40	$0	$40
Contingency (@25%)	$788	$0	$788
Total	$3,939	$0	$3,939
O&M			
Contractor (Developer)	$0	$1,150	$1,150
Contractor (Wholesale Operations)	$0	$405	$405
Internal Labor	$0	$0	$0
Materials	$0	$0	$0
Contingency (@25%)	$0	$389	$389
Total	$0	$1,943	$1,943
Grand Total	**$3,939**	**$1,943**	**$5,882**
Present Value of Total Costs			**$5,320**

Table 23: Ocean City 15 Year Project Revenue Requirements ($000's)[19]

	Present Value Inception - 12.31.36	Cumulative Inception - 12.31.36
Capital		
Contractor (Developer)	$3,009	$4,875
Contractor (Other)	$0	$0
Internal Labor	$0	$0
Materials	$174	$282
Interconnection/Permitting	$41	$66
Contingency (@25%)	$806	$1,306
Total	$4,030	$6,528
O&M		
Contractor (Developer)	$1,065	$1,725
Contractor (Wholesale Operations)	$385	$633
Internal Labor	$0	$0
Materials	$0	$0
Contingency (@25%)	$362	$590
Total	$1,812	$2,948
Grand Total	$5,842	$9,476

4.2.4 Project Benefits

The quantified project benefits over the expected 15-year life of the project are shown in Table 24 below and the unquantifiable benefits are shown in Table 25 below. Delmarva Power has listed each of the benefits identified in the PC44 Energy Storage Working Group's December 31, 2019 report, and where possible estimated a benefit. The quantified benefits that have values for the Ocean City project are briefly summarized below. Please refer to the PC44 Energy Storage Working Group Report for a description of the basis for the calculated value.

EPH 01 Air Emissions Reductions – Estimated dollar value of the net tons of greenhouse gas emissions reductions based on an assumption of 84 pounds per MWh of load shifted from an on-peak hour to an off-peak hour. It was assumed that the residential batteries

[19] Excludes non-incremental labor and overhead costs. Figures may not add due to rounding.

will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Delmarva Power's request.

EPJ 02 Public Health Benefits – Estimated dollar value of the public health benefits of shifting energy use from an on-peak hour to an off-peak hour in Maryland. The new EPA public health quantification tool assigns a value of $1.30 for each MWh of load shifted from an on-peak hour to an off-peak hour in Maryland. The EPA tool financially quantifies the health benefits value of particulate reduction, which is distinct for the other environmental benefits that are included. It was assumed that the residential batteries will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Delmarva Power's request.

PDR 01 Energy Conservation during Time of Peak – By reducing the need to supply customers during periods of peak demand, the utilities reduce the cost of delivering energy to customers during periods of high demand. The PC44 Energy Storage Working Group recommended using EmPOWER Maryland assumptions of the value of peak versus non-peak energy. It was assumed that the BESS will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Delmarva Power's request.

PDR 02 Peak Shaving (Zonal Capacity Obligation) – By reducing loads at the time of peak, the capacity obligation in the Maryland portion of the Delmarva Power Zone is reduced. It was assumed that load discharges occur during the top 5 PJM Peak Load Contribution ("PLC") hours each year.

PJM 05 Energy Arbitrage – By exporting energy from the BESS resource, the Ocean City project should benefit by selling energy into the market during high priced periods and consuming it during a low-priced period. The forecast of PJM revenue is based on analysis provided by CES.

PJM 06 Regulation – BESSs located in FTM are permitted to participate in the PJM regulation market. The Ocean City BESS will participate in the PJM Regulation D market when it is not needed for grid support or resiliency purposes, subject to the cycling capability of the BESS. The forecast of PJM revenue is based on analysis provided by CES.

Table 24: Ocean City Project Quantified Benefits ($000's)

Benefit Identifier	Benefit Description	Present Value (PV) at 12.31.21	Cumulative Benefits
Enviornmental & Public Health			
EPH 01	Air Emissions Reduction	$0.4	$0.6
EPH 02	Public Health Benefits	$0.3	$0.6
	Total	$0.7	$1.2
Distribution Grid Value			
DGV 01	Deferral/Avoidance of Utility Distribution Costs	$0	$0
DGV 02	Optionality	$0	$0
	Total	$0	$0
Peak Demand Reductions - Capacity & Energy			
PDR 01	Energy Conservation During Time of Peak	$4	$7
PDR 02	Peak Shaving (Zonal Capacity/Transmission Obligation)	$1,127	$1,847
	Total	$1,131	$1,853
PJM Market Activities			
PJM 01	Black Start	$0	$0
PJM 02	Capacity Price Earnings	$0	$0
PJM 03	Demand Response	$0	$0
PJM 04	Emergency Operations	$0	$0
PJM 05	Energy Arbitrage	$210	$344
PJM 06	Regulation	$1,302	$2,130
PJM 07	Reserves	$0	$0
	Total	$1,512	$2,474
	Total Benefits	**$2,644**	**$4,329**
	Total Costs (Revenue Requirements)	$5,842	$9,476
	Benefit-Cost Ratio	**0.45**	

The unquantified benefit value streams for the Ocean City project are shown in Table 25 below. These benefits include the following:

- NOx emissions reductions from both the avoided use of backup residential and commercial fossil fueled generators during outage events and large power plant emissions that are avoided by use of the batteries during peak load periods.

- Noise avoidance, which was not listed by the PC44 Energy Storage Working Group, by a reduction in the use of backup residential and commercial fossil fueled generators during outage events.
- Improved land use by lessening the need for additional distribution, transmission, and generation equipment to meet higher peak loads.
- Distribution hosting capacity improvement by supporting the ability to host additional photovoltaic arrays on the distribution system.
- Electric vehicle transportation support by potentially providing a source of energy for EV charging during grid outages through a direct connection to the public library facility and the charging loads it may support.
- Economic development by providing local Maryland jobs in Ocean City for installation and maintenance of the BESS.
- Learnings by providing a pilot utility owned/utility operated business model that will be used for peak shaving, emergency grid support, and participation in the PJM wholesale market. Learnings from the installation and operation of a BESS on a barrier island in an urban environment.
- Non-utility participation by using a competitively selected vendor and its subcontractors to install and operate the BESS.
- Grid services to support operational flexibility for the delivery of electricity – the availability of the BESS at Ocean City provides another tool to utility distribution control centers to manage the delivery of electricity by supporting the Delmarva Power ASR scheme.
- Resilience – availability to support outage restoration efforts in Ocean City and shorten their duration. Provides support for expanded use of the ASR scheme. Potential support for the adjacent library for community resiliency purposes.
- Other societal benefits – support for Ocean City beach community.
- Third party supplier participation – no impact on third-party suppliers.

Table 25: Ocean City Project Unquantified Benefits

No.	Value Streams	Project Applicability	Comments
1	NOx Emissions Reductions	●	Reduced PJM Generator Air Emissions and Use of Backup Generators
2	Land Use	●	Avoided Land Use for Distribution Upgrades to Serve Peak Loads
3	Distributed Generation Hosting Capacity		
4	Electric Vehicle Transportation	●	Possible Support for Nearby EV Chargers
5	Economic Development	●	Installation and Maintenance Services in Ocean City Area
6	Learnings	●	Unique PHI Business Model -- Utility Owned/Utility Operated
7	Non-Utility Participation	●	Third-Party Vendor and Subcontractors
8	Offshore Wind		
9	Grid Service -- Operational Flexibility Related to the Delivery of Electricity	●	Available for Delmarva Power use -- Peak Shaving and Emergency Grid Conditions. Support ASR Scheme and its Expansion
10	Resilience	●	Support Outage Restoration in Ocean City and Potential Support for Public Library Resiliency Center
11	Other Societal Benefits	●	Support for Ocean City Beach Community
12	Third Party Supplier Participation	●	No Impact
13	Customer Willingness-to-Pay		

4.2.5 Conclusion

The Ocean City project is not expected to have quantifiable benefits exceeding costs over the expected 15-year life of the BESS project. However, when combined with the unquantified benefits, this project will have benefits exceeding costs. The project will provide significant learnings for State policy makers regarding the integration and use of in FTM storage for Maryland customers and utilities on a barrier island in the Atlantic Ocean.

5.0 Pepco

The Pepco engineering planning team worked to identify energy storage project opportunities under the storage size constraints that would provide the most significant benefits to the its Maryland electric distribution system. The distribution benefits the engineers sought included: 1) deferral of new distribution or transmission investments at a lower cost than a traditional utility investment; 2) remedying an existing distribution system problem at a lower cost than a traditional utility investment; 3) improving distribution system reliability; 4) improving the DER hosting capacity of the distribution system; and 5) enhancing the resiliency of the distribution system. The Company's Utility of the Future team worked to identify additional project storage benefits for each proposed site that would improve the value of the storage installation at each identified location, including the uniqueness of the storage application and the potentially resulting business model that could provide unique and valuable learnings for Maryland electricity market stakeholders during the pilot period. The expected benefits of each project are provided below.

The engineering team identified twelve potential energy storage applications. These potential sites included: 1) a BESS located on Emory Grove Feeder No. 15257 to alleviate a 2 percent winter overload; 2) a BESS located on the Hunting Hill Feeder No. 15282 to alleviate a 2 percent summer overload; 3) a BESS located at the University of Maryland Campus Drive Substation to alleviate an overload that occurs when the University owned generation is off-line; 4) a BESS to improve DER hosting capacity at the Crain Highway Substation where the maximum generation threshold will be reached; 5) a BESS to improve DER hosting capacity at the St. Barnabas Substation where there is increasing potential for reverse power flow; 6) a BESS to improve DER hosting capacity by supporting St. Barnabas Feeder Nos. 15086 and 15082 due to restrictions caused by large existing DER generators; 7) a BESS to improve DER hosting capacity at Oak Grove Substation, where the reverse power buffer is being approached; 8) a BESS to improve DER hosting capacity near Crain Highway, where the reverse power buffer is being approached; 9) a BESS to improve DER hosting capacity that would be located at Beltsville Feeder 14470 to address the maximum large generation constraint; 10) a BESS to improve DER hosting capacity that would be located on Mt. Zion feeder MD 15901; 11) a BESS to defer a substation at

National Harbor in Prince George's County, Maryland; and, 12) a BESS to support a new Montgomery County Electric Bus Depot charging station. Pepco narrowed the list of potential energy storage projects to two based on the expected value (quantified and unquantified) of each application. This resulted in the selection of the storage opportunity at National Harbor to help defer the construction of a future planned substation and the selection of a storage opportunity at the Montgomery County Electric Bus Depot charging station to avoid the construction of an additional distribution feeder.

5.0.1 Communications

Pepco is undertaking a community outreach and engagement initiative to inform local public officials, customers, and the media of the benefits of energy storage technology and share information regarding the purposes of the Maryland Energy Storage Pilot Program. Pepco is committed to working with local public officials and community leaders to coordinate outreach within each community. The initiative will keep members of the community informed throughout the process and provide timely updates as key milestones are reached. Pepco has developed talking points and collateral materials to support this outreach. Initial steps were taken prior to the filing with the Commission to introduce the proposed projects to key stakeholders and answer questions. Following the filing, and as the projects move forward, broader outreach to media and community members will be undertaken to provide a summary of the benefits of the proposed projects in the National Harbor and the Electric Bus Depot communities.

5.0.2 Vendor Bids

As previously described, Pepco jointly issued an RFI with the other Joint Exelon Utilities. The RFI did not state a preference for a specific storage technology or a preferred business model. Six vendors responded to the RFI and provided their recommendations and capabilities.

Pepco prepared and issued an RFP on January 17, 2020, that was included as part of an RFP solicitation package with the other Joint Exelon Utilities. Vendor responses were due by February 19, 2020. Similar to the other Joint Exelon Utilities, the Pepco RFP sought a full requirements contract for BESS storage, installation, and maintenance over a 10-year period. The

RFP provided project site information, the planned use cases for the BESS at each site, and the detailed technical requirements of the utility. As noted earlier, the RFP was issued to 87 potential vendors. Thirteen vendors responded to the Pepco RFP and submitted 35 different proposals. Eight vendors submitted 14 bid proposals for the National Harbor Project and 11 vendors submitted 19 different proposals for the Montgomery County Electric Bus Depot Project. One vendor submitted a software proposal that was not responsive to the RFP request.

Table 26: Pepco Bid Proposal Summary

Business Model	National Harbor	Electric Bus Depot	Total
Utility Owned/Utility Operated	7	6	**13**
Utility Owned/Third Party Operated	2	3	**5**
Third Party Owned/Third Party Operated	4	9	**13**
Virtual Power Plant	1	1	**2**
Software Platform	1	1	**2**
Total	**15**	**20**	**35**

5.0.3 Vendor Selection

Pepco reviewed each proposal, the technical components of each proposal, and the vendor's experience and commercial capability. As discussed in the PC44 Energy Storage Working Group filing of August 1, 2019, final vendor contracts will be established for a 10-year period after the Commission approves each proposed project. The timing of Commission approval will determine when project implementation will begin and whether the targeted operational date of February 2022 will be met.

5.1 National Harbor Storage Proposal

Pepco has selected the National Harbor Storage Project to help defer the construction of a future distribution substation. Specifically, the existing Pepco Livingston Road Substation 151 is expected to have a 1 percent overload in 2027 and a 2 percent overload in 2028. The selected storage size at this location is recommended to be 1 MW with 3 MWH BESS in FTM. The BESS will be located on utility property. A utility owned/third party operated business model was selected for this site for the following reasons: 1) the property is owned by Pepco and is near the site of a future planned substation; 2) this is a unique storage project business model that has not been selected by any of the other three Pepco and Delmarva Power projects; and 3) it will offer pilot learnings regarding third party storage operation. The 1 MW/3 MWH BESS installed under the pilot program is expected to provide three hours of peak shaving capability to Pepco during periods of high load or emergency grid conditions in the National Harbor area, and to derive supporting revenue from the PJM wholesale electricity market for the third-party operator. The BESS will be located along the Pepco Right-of-Way near the Livingston Road substation. The BESS will be connected to Livingston Road Sub. 151 Feeder 14186. A picture of the expected location is shown below in Figure 5. Table 27 below provides a summary of the project.

Figure 5: National Harbor BESS Location

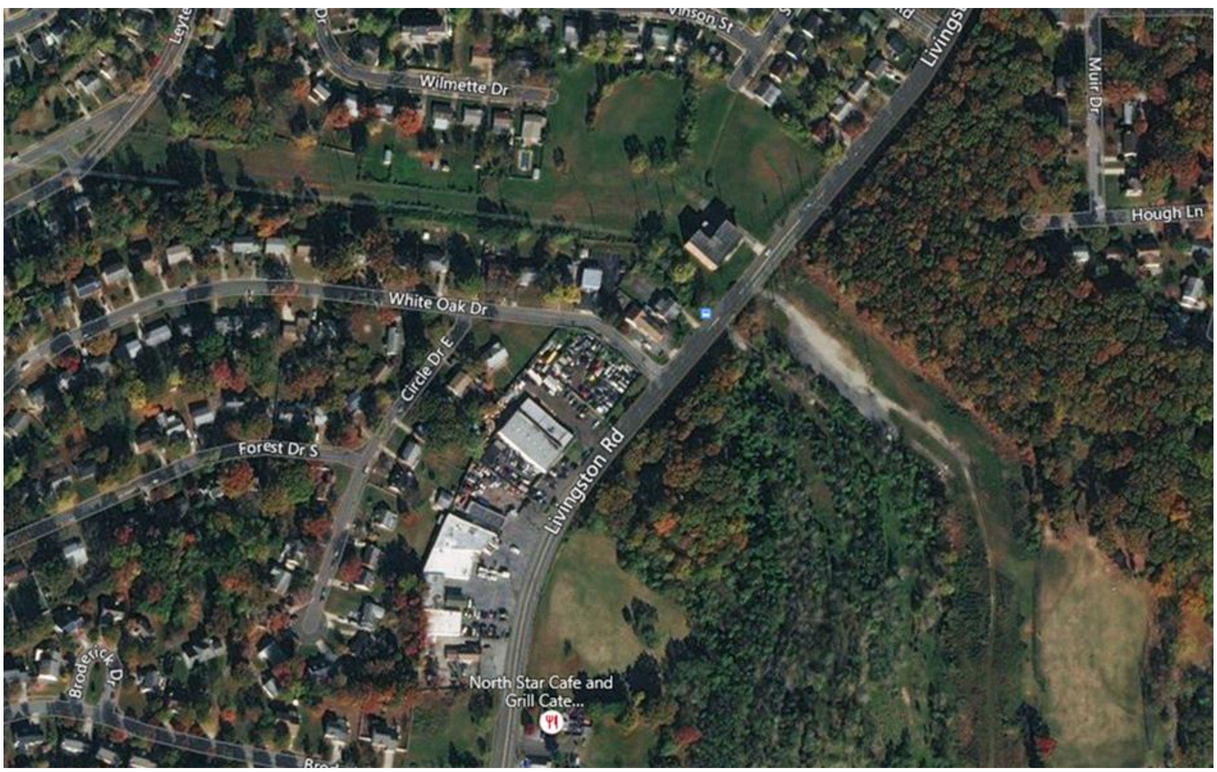


Table 27: National Harbor Project Summary

Category	Project Information
Required Capacity for Grid Reliability through the 10-year project term	1.0 MW/3.0 MWh
Initial Usable Capacity	1.05 MW/4.25 MWh
Business Model	Model 2: Utility Owned/3rd Party Operated – BTM
Project Developer	A.F. Mensah
Energy Storage Technology	Nickle Manganese Cobalt Lithium-Ion
Primary Application	Peak Shaving, Grid Reliability
Secondary Application	PJM Market Participation
Primary Location(s)	Livingston Road, MD
Expected Cost	\$4.6 million (\$4.4 million in present value) for 10-year term. \$8.1 million (\$4.7 million in present value) on a revenue requirement basis (15-year term).
Expected Benefits	\$15.4 million (\$11.1 million in present value) over a 15-year term and significant unquantified benefits.

5.1.1 Project Vendor

Pepco's proposed vendor for the installation and ongoing maintenance of the 1 MW/3 MWh is A. F. Mensah, Inc. ("AFM"), a minority business. The installed BESS will be a 1.05 MW BESS with 4.254 MWh of energy to meet the energy requirement of 1 MW/ 3 MWh over the 10-year period.

5.1.2 Project Specifics

AFM's plan for this project consists of installing modular BESS consisting of Lithium Iron Phosphate (LFP) battery modules and advanced battery inverters. Two racks will be installed consisting of 17 separate battery modules per modular BESS. The round-trip efficiency of the

BESS will be 96% initially and decline to 92% at the end of the 10-year period. AFM will rely on its strategic partnership with Kupper Engineering and Miller Brothers for project implementation. AFM will work as the third-party operator of the BESS under the 10-year period, and during this time will seek to maximize available earnings in the PJM market while meeting the peak shaving and grid reliability requirements of the utility contract. AFM will share market revenues above $100,000 annually on 60 AFM/40 Pepco split.

AFM has delivered eight battery systems to support the integration of DERs and is currently developing four battery projects, including the Baltimore Resiliency Hub Program, in partnership with Baltimore City Office of Sustainability (portfolio of 1 MW/1 MWh BESS) and a New Jersey battery farm composed of 14 MW/14 MWh BESS.

The use case for the installed BESS includes the following:

- Utility controlled operations during emergency grid conditions;
- Utility controlled peak shaving;
- PJM market use;
- Support for local customer loads; and
- Potential support for the integration of renewable technologies, if located at the site in the future.

5.1.3 Project Costs

The incremental 10-year project costs for the National Harbor Project are shown in Table 28 below. Additionally, since the batteries are expected to operate for a 15-year period, the revenue requirements are shown in Table 29 below for that period (this table includes incremental costs for a 15-year period). A contingency of 25% has been included due to the risks and uncertainties of the installation of a new non-wires alternative distribution system technology. For more information on how the Joint Exelon Utilities determine contingency, please see Appendix B below.

Table 28: National Harbor 10 Year Project Costs ($000's) [20]

	Deployment Phase Inception - 12.31.21	Operational Phase 1.1.22 - 12.31.31	Total Costs
Capital			
Contractor (Developer)	$2,914	$0	$2,914
Contractor (Other)	$0	$0	$0
Internal Labor	$0	$0	$0
Materials	$200	$0	$200
Interconnection/Permitting	$0	$0	$0
Contingency (@25%)	$779	$0	$779
Total	$3,893	$0	$3,893
O&M			
Contractor (Developer)	$0	$566	$566
Contractor (Wholesale Operations)	$0	$0	$0
Internal Labor	$0	$0	$0
Materials	$0	$0	$0
Contingency (@25%)	$0	$142	$142
Total	$0	$708	$708
Grand Total	**$3,893**	**$708**	**$4,600**
Present Value of Total Costs			**$4,366**

[20] Excludes non-incremental labor and overhead costs. Figures may not add due to rounding.

Table 29: National Harbor Project 15 Year Revenue Requirements ($000's)

	Present Value Inception - 12.31.36	Cumulative Inception - 12.31.36
Capital		
Contractor (Developer)	$3,045	$5,158
Contractor (Other)	$0	$0
Internal Labor	$0	$0
Materials	$209	$354
Interconnection/Permitting	$0	$0
Contingency (@25%)	$813	$1,378
Total	$4,067	$6,890
O&M		
Contractor (Developer)	$537	$971
Contractor (Wholesale Operations)	$0	$0
Internal Labor	$0	$0
Materials	$0	$0
Contingency (@25%)	$134	$243
Total	$671	$1,214
Grand Total	**$4,739**	**$8,104**

5.1.4 Project Benefits

The quantified project benefits over the expected 15-year life of the project are shown below and the unquantifiable benefits are shown in Table 30 below. Pepco has listed each of the benefits identified in the PC44 Energy Storage Working Group Report, and where possible estimated a benefit. Please refer to the Working Group for a description of the basis for the calculated value.

EPH 01 Air Emissions Reductions – Estimated dollar value of the net tons of greenhouse gas emissions reductions based on an assumption of 84 pounds per MWh of load shifted from an on-peak hour to an off-peak hour. It was assumed that the residential batteries will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Delmarva Power's request.

EPH 02 Public Health Benefits – Estimated dollar value of the public health benefits of shifting energy use from an on-peak hour to an off-peak hour in Maryland. The new EPA public health quantification tool assigns a value of $1.30 for each MWh of load shifted from an on-peak hour to an off-peak hour in Maryland. The EPA tool monetizes the health benefits value of particulate reduction, which is distinct for the other environmental benefits that are included. It was assumed that the residential batteries will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Pepco's request.

DGV 01 Deferral/Avoidance of Utility Distribution Costs – Value of BESS due to expected deferral of new substation.

DGV 02 Optionality – Value of BESS to potentially extend the substation deferral to a later time because of possible changes in load growth.

PDR 01 Energy Conservation during Time of Peak – By reducing the need to supply customers during periods of peak demand, the utilities reduce the cost of delivering energy to customers during periods of high demand. It was assumed that the BESS will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Delmarva Power's request.

PDR 02 Peak Shaving (Zonal Capacity Obligation) – By reducing loads at the time of peak, the capacity obligation in the Maryland portion of the Pepco Zone is reduced. It was assumed that peak load discharges occur during the top 5 PJM Peak Load Contribution ("PLC") hours each year.

PJM 05 Energy Arbitrage – By exporting energy from the BESS resource, the National Harbor project should benefit by selling energy into the market during high priced periods and consuming it during a low-priced period. The forecast of PJM revenue is based on analysis provided by CES.

PJM 06 Regulation – BESSs located in front-of-the-meter are permitted to participate in the PJM regulation market. The National Harbor BESS will participate in the PJM Regulation D market when it is not needed for grid support or resiliency purposes, subject to the cycling capability of the BESS. Because the business model is utility owned/third party operated a portion of the market earnings will be retained by the vendor as an operational incentive and a portion shared by Pepco. The figures shown here reflect the estimated quantity of revenue shared with Pepco.

Table 30: National Harbor Project Quantified Benefits ($000's) [21]

Benefit Identifier	Benefit Description	Present Value (PV) at 12.31.21	Cumulative Benefits
Enviornmental & Public Health			
EPH 01	Air Emissions Reduction	$0.4	$0.6
EPH 02	Public Health Benefits	$0.3	$0.6
	Total	$0.7	$1.2
Distribution Grid Value			
DGV 01	Deferral/Avoidance of Utility Distribution Costs	$7,761	$10,242
DGV 02	Optionality	$2,029	$2,919
	Total	$9,790	$13,161
Peak Demand Reductions - Capacity & Energy			
PDR 01	Energy Conservation During Time of Peak	$1	$2
PDR 02	Peak Shaving (Zonal Capacity/Transmission Obligation)	$1,061	$1,829
	Total	$1,063	$1,832
PJM Market Activities			
PJM 01	Black Start	$0	$0
PJM 02	Capacity Price Earnings	$0	$0
PJM 03	Demand Response	$0	$0
PJM 04	Emergency Operations	$0	$0
PJM 05	Energy Arbitrage	$0	$0
PJM 06	Regulation	$224	$390
PJM 07	Reserves	$0	$0
	Total	$224	$390
	Total Benefits	**$11,077**	**$15,383**
	Total Costs (Revenue Requirements)	**$4,739**	**$8,104**
	Benefit-Cost Ratio	**2.34**	

The unquantified benefit value streams for the National Harbor project are shown in Table 31 below. These benefits include the following:

- <u>NOx emissions reductions</u> from power plant emissions that are avoided by use of the batteries during peak load periods.

[21] Figures may not add due to rounding.

- Improved land use by lessening the need for additional distribution, transmission, and generation equipment to meet higher peak loads. Notably under the National Harbor the use of land for a future Pepco substation is deferred.
- Distribution hosting capacity improvement by supporting the ability to support additional local photovoltaic arrays on the distribution system.
- Economic development by providing local Maryland jobs for installation and maintenance of the BESS.
- Learnings by providing a pilot utility owned/third party operated business model that will be used for peak shaving, emergency grid support, and participation in the PJM wholesale market. Learnings from the installation and operation of a BESS to support the deferral of a planned distribution substation.
- Non-utility participation by using a competitively selected vendor and its subcontractors to install and operate the BESS.
- Grid services to support operational flexibility for the delivery of electricity – the availability of the BESS at National Harbor provides another tool to utility distribution control centers to manage the delivery of electricity.
- Resilience – availability to support outage restoration efforts in the National Harbor area and shorten duration.
- Other societal benefits – an electric distribution investment in Prince George's County using new technology for a non-wires grid solution.
- Third party supplier participation – no impact on third-party suppliers.

Table 31: National Harbor Unquantified Benefits

No.	Value Streams	Project Applicability	Comments
1	NOx Emissions Reductions	●	Reduced PJM Generation Emissions
2	Land Use	●	Deferral of Pepco Substation
3	Distributed Generation Hosting Capacity	●	Support for Regional PV Installations
4	Electric Vehicle Transportation		
5	Economic Development	●	Installation and Maintenance Services in Prince George's County
6	Learnings	●	Unique PHI Business Model -- Utility Owned and Operated
7	Non-Utility Participation	●	Use of Third Party Vendor for Project Implementation and Operation
8	Offshore Wind		
9	Grid Service -- Operational Flexibility Related to the Delivery of Electricity	●	Available for Pepco use -- Peak Shaving and Emergency Grid Conditions
10	Resilience	●	More Flexible Crew Restoration Work during Large-Scale Outages
11	Other Societal Benefits	●	Electric Distribution Investment in Prince George's County using new technology.
12	Third Party Supplier Participation	●	No impact.
13	Customer Willingness-to-Pay		

5.1.5 Conclusion

The National Harbor project is expected to have quantifiable benefits that are expected to exceed costs over the 15-year life of the BESS project. The benefit/cost of the project on a 15-year revenue requirements basis is estimated at 2.34. The project's unquantified benefits will further improve the cost-effectiveness of the National Harbor project. This project will also provide important learnings for Maryland electricity market stakeholders.

5.2 Montgomery County Bus Depot Storage Proposal

The second storage opportunity proposed is at the planned Montgomery County Electric Bus Depot in Silver Spring, Maryland. The installation of a BESS at this location provides an opportunity to help defer or avoid a feeder upgrade that will be necessary to serve the additional load resulting from electric bus charging, provide additional reliability support for bus charging during distribution system outage events, and to potentially be recharged by a solar array installed at the location.

The electric bus deployment schedule together with the annual charging station energy consumption is identified in Table 32. The selected energy storage size at this location is recommended to be a 1 MW BESS with 3 MWH of energy. The installed BTM BESS will be located at the transit bus depot on property owned by Montgomery County. The selected storage model for this project is third party owned and third party operated behind-the-meter storage. This model was selected for this site for the following reasons: 1) ownership and development of the Electric Bus Depot by the Montgomery County Government; 2) the use of the BESS to balance loads and energy supply in the planned microgrid at this site; and 3) the uniqueness of the business model for the four proposed Pepco and Delmarva Power storage projects.

Table 32: Montgomery County Electric Bus Deployment Schedule

Year	Electric Buses	Annual MWH
2021	14	3,700
2022	24	6,300
2023	34	9,000
2024	44	11,600
2025	57	15,000
2026	70	18,000

The installed BESS is expected to provide three hours of peak shaving capability to Pepco during periods of high load at the electric transit bus depot or emergency grid conditions in the Silver Spring area. During other periods the BESS will be used by the third-party owner to reduce peak electric demand, be potentially charged by solar photovoltaic arrays at the site or available on-site generation, and to support bus recharging during grid outage events. The installed BESS at the bus depot are expected to avoid the need to install an additional Pepco electric feeder to the station at a cost of $3.6 million.

The expected location of the installed BESS is on the Montgomery County Bus Depot property. Figure 6 below is a photograph of the anticipated location of the BESS. The planned point of interconnection to the Pepco distribution system is at the Linden Substation 156 Feeder 14264, which is located along Brookville Road. Table 33 below provides a summary of the project.

Figure 6: Electric Bus Depot BESS Location

Table 33: Electric Bus Depot Project Summary

Category	Project Information
Required Capacity for Grid Reliability through the 10-year project term	1.0 MW/3.0 MWh
Initial Usable Capacity	1.5MW/4.3 MWh
Business Model	Model 3: 3rd Owned/3rd Party Operated - BTM
Project Developer	AlphaStruxure
Energy Storage Technology	Nickel Metal Chloride Lithium-Ion
Primary Application	Peak Shaving, Grid Reliability
Secondary Application	Customer site demand management. Charging during outages. Microgrid integration with photovoltaic array
Primary Location(s)	Brookville Road, Silver Spring, MD
Expected Cost	\$2.6 million (\$1.9 million in present value) for 10-year term. \$4.3 million (\$2.5 million in present value) on a revenue requirement basis (15-year term).
Expected Benefits	\$8.1 million (\$4.8 million in present value) over a 15-year term and significant unquantified benefits.

5.2.1 Project Vendor

AlphaStruxure is the proposed third-party developer, operator, and owner of the bus depot BESS. AlphaStruxure is a joint venture of The Carlyle Group and Schneider Electric. The Montgomery County Government has also selected this vendor as the developer of a microgrid at the Brookville bus depot. The installed microgrid is designed to serve the electric bus charging equipment through a combination of solar photovoltaic arrays, gas generation, and lithium-ion batteries.

Schneider Electric is currently delivering two advanced microgrids that increase resiliency and sustainability at the Public Safety Headquarters and Montgomery County Correctional Facilities. Schneider Electric also developed a project at the Shedd Aquarium in Chicago. This installation included a 1MW/250 kWh lithium ion BESS energy storage solution that was designed by Schneider Electric. The installed BESS is also enrolled in an ancillary service program with Commonwealth Edison and provides PJM Regulation D frequency regulation services. The BESS serves as an energy supply for Shedd Aquarium to use during peak-load periods and can supply emergency back-up power.

The Carlyle Group is a global investment firm that has energy infrastructure investments that include more than 90 active energy, natural resource, and infrastructure investments. Carlyle's current North American portfolio of power investments consists of more than 20 assets with a total net capacity of 8,655 MW.

5.2.1 Project Specifics

The installed BESS system is expected to include three Schneider Electric nickel metal chloride lithium-ion 500 kW batteries each with 1,140 kWh of energy. In aggregate, 1.5 MW with 3.4 MWH of energy is expected to be installed at the site. Final BESS design characteristics may be revised prior to project implementation – revisions could include the number of distinct batteries, battery chemistry, and the battery supplier. As previously stated, Pepco will contract to use 1 MW and 3 MWh of the installed batteries over a 10-year period. An additional contract could be established between Pepco and AlphaStruxure for the remaining life of the batteries (estimated at 15 years) depending upon electric distribution system needs during that time period.

Pepco will notify AlphaStruxure 24 hours in advance of its planned use of the BESS. The BESS will then be operated to discharge 3 MWh of energy over a period that will not exceed 3 hours. Pepco will have the right to call up to 10 days for peak shaving and additional days for grid emergencies. The BESS will be used for multiple purposes in both grid-connected and islanded modes of operation. While grid connected, the system will help to offset peak demand as required. It will function as a backup for any unexpected loss of onsite generation with the capability of responding to any loss in under a second. While in islanded mode, the BESS can serve as an Electric Bus Depot energy resource and will be used for solar photovoltaic smoothing and helping with voltage and frequency sags and swells.

AlphaStruxure will have the right to operate the BESS during all other periods to support the electric bus charging depot as it deems appropriate. It will function as a backup for any unexpected loss of onsite generation with the capability of responding to any loss in under a second. While in islanded mode, the BESS can serve as an Electric Bus Depot energy resource and will be used for solar photovoltaic smoothing and helping with voltage and frequency sags and swells. The Pepco/AlphaStruxure contract will be established for a 10-year period after Commission approval of the project is received. The timing of Commission approval will determine the scheduled project completion date.

5.2.3 Project Costs

The incremental 10-year project costs for the Electric Bus Depot Project are shown in Table 34 below. Additionally, since the batteries are expected to operate for a 15-year period, the revenue requirements are shown below in Table 35 for that period (this table includes incremental costs for a 15-year period). A contingency of 15% has been included due to the risks and uncertainties of the installation of a new non-wires alternative technology by a third-party vendor under the overall direction of the Montgomery County Government. For more information on how the Joint Exelon Utilities determine contingency, please see Appendix B.

Table 34: Electric Bus Depot 10 Year Incremental Project Costs ($000's) [22]

	Deployment Phase Inception - 12.31.21	Operational Phase 1.1.22 - 12.31.31	Total Costs
Capital			
Contractor (Developer)	$0	$0	$0
Contractor (Other)	$0	$0	$0
Internal Labor	$0	$0	$0
Materials	$230	$0	$230
Interconnection/Permitting	$0	$0	$0
Contingency (@15%)	$35	$0	$35
Total	$265	$0	$265
O&M			
Contractor (Developer)	$0	$2,103	$2,103
Contractor (Wholesale Operations)	$0	$0	$0
Internal Labor	$0	$0	$0
Materials	$0	$0	$0
Contingency (@15%)	$0	$316	$316
			$0
Total	$0	$2,419	$2,419
Grand Total	**$265**	**$2,419**	$2,683
Present Value of Total Costs			**$1,911**

[22] Excludes non-incremental labor and overhead costs. Figures may not add due to rounding.

Table 35: Electric Bus Depot 15 Year Revenue Requirements Costs ($000's)[23]

	Present Value Inception - 12.31.36	Cumulative Inception - 12.31.36
Capital		
Contractor (Developer)	$0	$0
Contractor (Other)	$0	$0
Internal Labor	$0	$0
Materials	$249	$423
Interconnection/Permitting	$0	$0
Contingency (@15%)	$37	$63
Total	$287	$486
O&M		
Contractor (Developer)	$1,905	$3,304
Contractor (Wholesale Operations)	$0	$0
Internal Labor	$0	$0
Materials	$0	$0
Contingency (@15%)	$286	$496
Total	$2,191	$3,800
Grand Total	**$2,478**	**$4,286**

5.2.4 Project Benefits

The quantified project benefits over the expected life of the BESS are shown in Table 36 below and the unquantifiable benefits are shown in Table 37 below. Pepco has listed each of the benefits identified in the PC44 Energy Storage Working Group December 31, 2019 report, and where possible estimated a benefit. Please refer to the Working Group report for a description of the basis for the calculated value.

EPH 01 Air Emissions Reductions – Estimated dollar value of the net tons of greenhouse gas emissions reductions based on an assumption of 84 pounds per MWh of load shifted from an on-peak hour to an off-peak hour. It was assumed that the BESS will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Pepco's request. Other hours of BESS operation will be determined by the needs of the third-party owner/operator.

[23] Figures may not add due to rounding.

EPJ 02 Public Health Benefits – Estimated dollar value of the public health benefits of shifting energy use from an on-peak hour to an off-peak hour in Maryland. The new EPA public health quantification tool assigns a value of $1.30 for each MWh of load shifted from an on-peak hour to an off-peak hour in Maryland. The EPA tool monetizes the health benefits value of particulate reduction, which is distinct for the other environmental benefits that are included. It was assumed that the BESS will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Pepco's request. Other hours of BESS operation will be determined by the needs of the third-party owner/operator.

DGV 01 Deferral/Avoidance of Utility Distribution Costs – Value of avoiding the construction of an additional Pepco feeder to the electric bus depot during the 15-year life of the BESS.

PDR 01 Energy Conservation during Time of Peak – By reducing the need to supply customers during periods of peak demand, the utilities reduce the cost of delivering energy to customers during periods of high demand. The PC44 Energy Storage Working Group recommended using EmPOWER Maryland assumptions of the value of peak versus non-peak energy. It was assumed that the BESS will discharge 12 days per year (10 peak days/2 emergency events) during peak load periods based upon Pepco's request. Other hours of BESS operation will be determined by the needs of the third-party owner/operator.

PDR 02 Peak Shaving (Zonal Capacity Obligation) – By reducing loads at the time of peak, the capacity obligation in the Maryland portion of the Pepco Zone is reduced. It was assumed that peak load discharges occur during the top 5 PJM Peak Load Contribution ("PLC") hours each year.

Table 36: Electric Bus Depot Project Quantified Benefits ($000's)

Benefit Identifier	Benefit Description	Present Value (PV) at 12.31.21	Cumulative Benefits
Enviornmental & Public Health			
EPH 01	Air Emissions Reduction	$0.4	$0.6
EPH 02	Public Health Benefits	$0.3	$0.6
	Total	$0.7	$1.2
Distribution Grid Value			
DGV 01	Deferral/Avoidance of Utility Distribution Costs	$3,761	$6,372
DGV 02	Optionality	$0	$0
	Total	$3,761	$6,372
Peak Demand Reductions - Capacity & Energy			
PDR 01	Energy Conservation During Time of Peak	$4	$7
PDR 02	Peak Shaving (Zonal Capacity/Transmission Obligation)	$1,028	$1,744
	Total	$1,031	$1,750
PJM Market Activities			
PJM 01	Black Start	$0	$0
PJM 02	Capacity Price Earnings	$0	$0
PJM 03	Demand Response	$0	$0
PJM 04	Emergency Operations	$0	$0
PJM 05	Energy Arbitrage	$0	$0
PJM 06	Regulation	$0	$0
PJM 07	Reserves	$0	$0
	Total	$0	$0
	Total Benefits	**$4,794**	**$8,123**
	Total Costs (Revenue Requirements)	**$2,478**	**$4,286**
	Benefit-Cost Ratio	**1.93**	

The unquantified benefit value streams for the Electric Bus Depot Project are shown in Table 37 below. These benefits include the following:

- NOx emissions reductions from both the avoided use of backup residential and commercial fossil fueled generators during outage events and also large power plant emissions that are avoided by use of the batteries during peak load periods.
- Improved land use by lessening the need for additional distribution, transmission, and generation equipment to meet higher peak loads.
- Distributed generation hosting capacity improvement by supporting the ability to integrate the use of solar photovoltaic arrays at the electric bus depot.
- Electric vehicle transportation support for the Montgomery County electric bus depot.
- Economic development by providing local Maryland jobs for installation and maintenance of the BESS.
- Learnings by providing a pilot third party owned/third party operated business model that will be used for peak shaving, emergency grid support, management of electric charging loads, support for solar photovoltaic integration, and charging reliability.
- Non-utility participation by using a competitively selected vendor and its subcontractors to install and operate the BESS. Montgomery County Government owned electric bus depot.
- Grid services to support operational flexibility for the delivery of electricity – the availability of the BESS at the electric bus depot provides another tool to utility distribution control centers to manage the delivery of electricity.
- Resilience – availability to support outage restoration efforts in the Silver Spring area and shorten their duration.
- Other societal benefits – support for bus transit riders.
- Third party supplier participation – support for establishment of a microgrid at the Electric Bus Depot.

Table 37: Electric Bus Depot BESS Unquantified Benefits

No.	Value Streams	Project Applicability	Comments
1	NOx Emissions Reductions	●	Reduced PJM Generator Air Emissions
2	Land Use	●	Avoidance of Second Pepco Feeder Supply
3	Distributed Generation Hosting Capacity	●	Support for PV Arrays at Electric Bus Depot
4	Electric Vehicle Transportation	●	Support for 70 Electric Montgomery Transit Buses
5	Economic Development	●	Installation and Maintenance Services in Prince George's County
6	Learnings	●	Unique PHI Business Model -- Third Party Owned and Operated
7	Non-Utility Participation	●	Third Party Ownership + Montgomery Government Bus Depot Project
8	Offshore Wind		
9	Grid Service -- Operational Flexibility Related to the Delivery of Electricity	●	Available for Pepco use -- peak shaving and emergency grid conditions
10	Resilience	●	More flexible crew restoration work during large-scale outages
11	Other Societal Benefits	●	Support for Montgomery County Transit Buses
12	Third Party Supplier Participation	●	Support for Electric Transit Bus Microgrid
13	Customer Willingness-to-Pay	●	Montgomery County Financial Contribution to BESS Costs

5.2.5 Conclusion

The Montgomery County Electric Bus Depot project is expected to have quantifiable benefits are expected to exceed costs over the expected 15-year life of the BESS project. The benefit/cost of the project on a 15-year revenue requirements basis is estimated at 1.93. Expected unquantified benefits, including learnings from this third-party model, will further improve the cost-effectiveness of the Montgomery County Electric Bus Depot project, and learnings from the project will benefit Maryland electricity market stakeholders. This project will directly support the electrification of transportation, a policy goal of Maryland.

6.0 Cost Recovery

For all third-party owned projects, the Joint Exelon Utilities propose that all incremental operations and maintenance ("O&M") costs, including the grid reliability payments to the proposed developer, be included in a newly established regulatory asset. This regulatory asset shall also be included in rate base, and recovery of the regulatory asset shall be requested in future base rate proceedings. Capital costs associated with the implementation of the projects will be included in rate base and recovered in base rates. Any PJM revenues associated with the projects during the 10-year term will be credited to customers.

For all the projects that are utility-owned**,** the Joint Exelon Utilities propose that the capital and O&M costs associated with the implementation of the projects be included in rate base and recovered in base rates. Any annual PJM market revenue would be credited to customers.

It is important to note that the ability to capitalize and earn a return on third-party grid reliability service costs is a crucial first step to creating a level playing field in which the utility faces economically equivalent revenue models, and thus seeks out and implements the option that maximizes system and customer benefits. This approach ensures that the utility is indifferent between traditional and non-wire alternative solutions, and indifferent between non-wire alternative solutions that are utility-owned and third-party owned. In this way, the utility is able to select the most cost-effective solutions that deliver the same degree of system reliability.

This also ensures that utilities will retain the ability to fund further grid investment. As third-party grid reliability options continue to develop, this levelized playing field will allow utilities to take advantage of third-party services, and assuming they provide the same degree of reliability, provide solutions with less overall cost to customers.

As these programs evolve and mature, it is important to look at jurisdictions such as New York, where non-traditional projects that can demonstrate a material cost savings versus the traditional option can earn an additional incentive beyond the authorized return. Other jurisdictions, such as Massachusetts, have also recognized the need to allow equal treatment between capital investments and O&M to ensure that utilities can make investments in a way that maximizes benefits without any improper incentive to favor capital investments over non-capital expenditure approaches.

Finally, the utility must seek to execute commercial terms or other protections to ensure that third-party grid reliability service providers deliver the grid services on which the grid solution is premised. Utilities are held accountable for overall system performance and reliability, and any failures will ultimately reside with the utility to resolve. This new approach introduces a new type of risk for utilities to manage and, while contractual penalties may provide some financial recovery, it is likely to be significantly smaller than the potential cost of a reliability event on to utility customers.

6.1 Cost Impacts to Customers

The Joint Exelon Utilities present the following rate impact information based on calculations of the levelized revenue requirement for incremental storage costs. BGE projected bill impacts are shown over a 30-year period and Pepco/Delmarva bill impacts are shown over a 15-year period, corresponding to the number of years incorporated into the BCA for the respective projects. Benefit streams that offset the project costs in the shown rate impacts include Deferred/Avoided Distribution Investments and available PJM revenues. Note that the rate impacts indicate how the rates will differ from the rates that would have been in effect in the absence of the project, not compared with the existing rates.

Table 38: BGE Monthly Customer Bill Savings by Rate Class[24]

Combined Impact of BESS at Fairhaven Substation and Chesapeake Beach Project	
Rate Class	Increase to bill / (Reduction to bill)
Schedule R	($0.01)
Schedule RL	($0.02)
Schedule G/GU	($0.03)
Schedule GS	($0.10)
Schedule GL	($0.57)
Schedule P	($6.34)
Schedule T	($11.84)

Table 39: Delmarva Power Net Monthly Customer Bill Impact[25]

Rate Class	Elk Neck	Ocean City
Residential	$0.09	$0.11
Small Commercial	$0.24	$0.31
Medium Commercial	$0.60	$0.77
Large Commercial	$15.39	$19.78

Table 40: Pepco Net Monthly Customer Bill impact[25]

Rate Class	National Harbor	Electric Bus Depot
Residential	($0.02)	($0.01)
Small Commercial	($0.03)	($0.01)
Medium Commercial	($0.57)	($0.22)
Large Commercial	($18.80)	($7.24)

[24] Based on 30-year levelized revenue requirements.
[25] Based on 15-year levelized revenue requirements.

7.0 Reporting

The Joint Exelon Utilities recommend that the Commission direct the PC44 Maryland Energy Storage Working Group to develop a comprehensive set of pilot reporting metrics for each approved storage project. The metrics would include the value streams identified in the PC44 Energy Storage Working Group's December 31, 2019 report, any additional metrics identified in the Act or through Commission orders, and any new value streams identified under a specific approved project proposal.

Appendix A: List of Vendors included in the RFP

- F. Mensah
- ABB Inc
- Alpha Struxure
- ALSTOM Grid
- Ameresco
- AutoGrid Systems*
- Bidgely Inc.
- Black & Veatch
- Borrego Solar Systems Inc.
- Centrica
- CLEAResult Consulting, Inc
- Compass Energy
- Con Edison Development
- Constellation NewEnergy, Inc.
- Conti Solar LLC
- Convergent Energy and Power LP
- CPower
- Cypress Creek Renewables
- DNV GL
- Doosan GridTech Inc
- EAST POINT ENERGY
- EDF Renewables
- Enbala
- Enel Green Power North America, Inc.
- EnergyHub
- Enerwise Global Technologies, LLC
- ENGIE Development LLC
- Eos Energy Storage
- Fluence Energy LLC
- Fluence/Siemens
- GE Energy Management
- Generac Power Systems
- Greensmith Energy
- Greensync
- Honeywell
- Ice Energy Holdings, Inc.
- ICF
- Invenergy
- Itron, Inc.*
- Johnson Controls Govt Svs
- Kitu Systems, Inc.
- KORE Power
- Leclanche SA
- Leclanche North America
- Lockheed Martin
- MESA
- Mitsubishi
- Mitsubishi Electric Power Products, Inc.
- NEC Energy Solutions
- NextEra Energy Resources
- Noresco, LLC
- Northern Reliability
- NRG Business Solutions
- Open Access Technology International, Inc
- Peak Power
- Power Edison LLC
- Powin Energy Corp
- PPL Corporation
- Recurrent Energy
- RES Group
- Robinson Sales Inc
- Schneider Electric USA*
- Shell New Energies US LLC
- Siemens Industry, Inc* (USE FOR UTILITIES BIDS)
- SMA America LLC
- Sonnen, Inc.
- Standard Energy Solutions
- Stem
- SUNGROW-SAMSUNG SDI ENERGY STORAGE POWER SUPPLY Co., Ltd.
- Sunnova Energy Corporation
- SunPower Corporation
- Sunrun Inc.
- SunTrail
- Sunverge
- Tendril EA, LLC

- Tesla
- Tesla SolarCity
- The Worley Group, Inc.
- TPE Development, LLC
- Turning Point Energy
- Uplight, Inc.
- Viridity Energy Solutions, Inc.
- Virtual Peaker
- Wartsila North America

Appendix B: Contingency Calculations

Exelon has reviewed all the potential risk associated with its proposed utility-owned storage, third-party-owned storage, and VPP storage projects.

Based on the below categories of risks, a 25% contingency rate has been assigned to the utility-owned projects, 20% contingency rate has been assigned to VPP projects, and a 15% contingency rate has been assigned for third-party-owned projects. A 15%-25% contingency is typical for projects that are new or novel to Exelon and have yet to be negotiated with vendors.

A lower level of perceived risk is assumed by Exelon for third-party-owned projects due to multiple risks being transferred to the third party to manage. All risk has an expected impact to the project of increased cost or schedule.

Risk	Risk Description	Risk Utility Owned Project	Risk Virtual Power Plant	Risk 3rd Party Project
Bids	If contractor bids come in higher than expected.	Low	Low	Low
Budget	If funding approval is delayed or budget is moved into a future year.	Low	Low	Low
Community Opposition	If there is opposition from surrounding communities requiring unexpected scope or schedule changes to the project.	Moderate	Low	Low
Damages	If damages occur to company or customer property.	Low	Moderate	Low
Engineering	If there are unforeseen engineering or standard changes.	Moderate	Moderate	Low
Environmental	If there are stormwater management or soil concerns that need to be addressed.	Low	Low	Low
Equipment	If equipment is not received by the scheduled milestone.	Low	Low	Low
Estimate	If cost come in higher than estimated.	Moderate	Low	Low

Feasibility	If the space constraints are not feasible and modifications must be made.	Moderate	High	Low
Foundations	If the foundation work is greater than expected for than expected.	Low	Low	Low
Operational	If regulatory requirements take longer to complete than planned or are greater than expected.	Moderate	Moderate	Low
Outages	If the outages on the project are delayed or cancelled due to weather or operational needs.	Moderate	Low	Low
Permitting	If permits are delayed being received or unexpected requirements are assigned by municipalities as conditions of a permit.	Moderate	Low	Low
Resources	If we experience delays to the project due to the Corona19 virus.	Moderate	Moderate	Moderate
Schedule	If the vendor is required to bring on additional resources or work overtime in order to meet the project In Service Date.	Moderate	Moderate	Low
Schedule	If there are delays in the PSC approval of project creating delays in the award to the EPC vendor.	Moderate	Moderate	Moderate
Scope Changes	If there are scope changes that are necessary for the project in the design or execution phase.	High	Moderate	Moderate
Site Restoration	If the site restoration after the project is complete is greater than expected.	Moderate	None	Low
Site Conditions	If the project site conditions are impacted by weather, rock, slag, or obstructions.	High	Low	High
Customer	If there are delays in acquiring customers to participate in a VPP	None	High	None