ERRATA
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ORDER NO. 89664

In the Matter of The Maryland Energy Storage Pilot Program	* * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND Case No. 9619

Issue Date: November 6, 2020

ORDER ON ENERGY STORAGE PILOT PROPOSALS

1. On August 23, 2019, pursuant to authority granted under Annotated Code of Maryland, Public Utilities Article ("PUA"), *Annotated Code of Maryland,* § 7-216 (the Energy Storage Act of 2019), the Commission established the Energy Storage Pilot Program (the "Pilot"). On April 15, 2020, Baltimore Gas and Electric Company ("BGE"), the Potomac Electric Power Company ("Pepco"), and Delmarva Power & Light Company ("Delmarva") (collectively, the "Exelon Companies") and the Potomac Edison Company ("Potomac Edison") filed Pilot program applications. Following notice and an opportunity for stakeholder comment, on July 13, 2020, the Commission held a legislative-style hearing to consider those applications. For the reasons discussed herein, the Commission approves, subject to the modifications discussed below, the six projects proposed by the Exelon Companies. The Commission rejects Potomac Edison's Little Orleans project and defers consideration of its Town Hill proposal.

Background

2. In 2019, the Maryland General Assembly amended PUA § 7-216 to require the Commission to establish an energy storage pilot program wherein each investor-owned electric utility ("IOU") operating in Maryland would propose two energy storage projects, to be owned and operated under two of four possible frameworks: (1) utility-owned and operated; (2) utility-owned and third party operated; (3) third-party owned and operated; and (4) virtual power plant.[1]

3. On August 23, 2019, the Commission issued Order No. 89240 initiating the Energy Storage Pilot Program and also directing the Commission's existing Energy Storage Working Group ("WG") to propose metrics on environmental and clean energy objectives and impacts on the retail energy market, and to propose a list of the types of value streams each project application should consider. On December 31, 2019, the WG filed its report on proposed metrics and value streams.[2]

4. On April 15, 2020, the Exelon Companies filed a joint application for two battery energy storage systems ("BESS") within each of their three service areas.[3] Also on April 15, 2020, Potomac Edison filed an application for two BESS projects within its service area (the "Little Orleans" and "Town Hill" projects).[4]

5. On July 7, 2020, Potomac Edison filed an amended application, withdrawing its Little Orleans proposal and revising its Town Hill proposal based on the stakeholder feedback it had received.[5]

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[1] Order No. 89240.
[2] Maillog No. 228020.
[3] Maillog No. 229744 ("Exelon Companies Application").
[4] Maillog No. 229737.
[5] Maillog No. 231036.

6. The Commission also received filings from parties offering their general support of this Pilot and of the projects proposed. Those parties included elected Maryland officials;[6] the Energy Storage Association;[7] the Maryland League of Conservation Voters;[8] the University of Maryland Medical Center;[9] the University of Maryland;[10] the Maryland-DC-Virginia Solar Energy Industries Association;[11] the Maryland Clean Energy Center;[12] and the Future of Energy Initiative.[13]

7. On July 13, 2020, the Commission held a legislative-style hearing.[14] As part of that hearing, the Commission addressed the six Exelon Companies' projects but ultimately deferred consideration of the Potomac Edison projects so both projects could be considered together at a later date.[15] For that reason, this Order will primarily discuss the Exelon Companies' proposals.

8. On September 15, 2020, Potomac Edison filed a notice asking that the Commission reject its Little Orleans proposal and that it would look to develop another project for consideration by the Commission.[16]

1. Comments by Stakeholders

9. In addition to project-specific concerns discussed below, Stakeholders identified concerns applicable to some or all of the projects.

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[6] Maillog Nos. 230351 and 230801.
[7] Maillog No. 230812.
[8] Maillog No. 230549.
[9] Maillog No. 230648.
[10] Maillog No. 230808.
[11] Maillog No. 230802.
[12] Maillog No. 230809.
[13] Maillog No. 230827.
[14] Citations to the transcript from that hearing appear throughout as "Hearing Transcript."
[15] Hearing Transcript at 138-139 and 145-146.
[16] Maillog No. 231846.

a. Cost Benefit Analyses

10. Pursuant to PUA §7-216(e) the Exelon Companies provided a benefit cost analysis ("BCA") to support their proposed projects, which they describe as consistent with the WG's December 31, 2019 filing.[17] This analysis includes quantifiable value streams and calculates a ratio of present value benefits versus costs for all six proposals.[18] A number of key assumptions were made including discounting based on the utility's weighted average cost of capital ("WACC"),[19] charge discharge profiles, benefit lives based on the economic life of the investments,[20] optionality benefits,[21] and cash flows for avoided distribution elements calculated on a revenue requirements basis.[22] Commission's Technical Staff ("Staff") noted that for some of these elements the Exelon Companies made differing assumptions across the projects.[23] Unquantifiable benefits are described but are not assigned a monetary value.

11. Staff's cost benefit analysis used consistent assumptions across all eight proposed projects in order to "level" the comparisons. Staff made the following assumptions: (1) all projects will be amortized over 15 years; (2) all projects will cease operations after 10 years; (3) any deferred distribution system needs would be implemented after 10 years; and (4) any long term assets installed to support the BESS are amortized over their

[17] Exelon Companies Application at 23-25, 41-47, 52-57, 64-69, and 75-80. The filing included four categories of metrics with value streams that could be assigned quantifiable monetary value including: (1) environmental and public health benefits; (2) distribution grid value (e.g. deferred investment); (3) peak demand reduction; and (4) PJM market activities.
[18] *Id*.
[19] Net of tax WACC. Exelon Companies Application at 26.
[20] 30 years for traditional distribution investments, Exelon Application at 26.
[21] Exelon Companies Application at 28.
[22] *Id*. at 26.
[23] Maillog No. 230825 ("Staff Comment") at 8. Staff also filed updated Errata comments on July 10, 2020. Maillog No. 231084.

expected useful lives and included in the cost benefit analysis.[24] In addition, Staff provided an alternative analysis extending the installations' useful lives to 15 years but cautioned against "giving too much weight to this analysis."[25]

12. The Maryland Office of People's Counsel's ("OPC") analysis reviewed the Exelon Companies' BCAs to check calculations and methods, consistency with the WG recommendations, reasonableness of costs, and proposed qualitative benefits.[26] In reviewing these elements, OPC raised issues with both the wholesale market revenues and emissions calculations.

13. First, OPC expressed concern that **most** of the projects depended on earning revenues via participation in PJM's wholesale electricity markets, some of which OPC stated could become saturated, thus lowering revenues below those projected.[27] Relatedly, OPC recommended that the Commission require that all utilities demonstrate that each project **expected to participate in PJM markets** meets all technical specifications and performance standards for participation in PJM's markets.[28]

14. Second, OPC along with Staff raised concerns regarding emissions from round-trip efficiency losses. These are losses resulting from the charging, storing and discharging cycle of the battery. OPC concluded that the both BGE projects as well as Delmarva's Ocean City project and Pepco's National Harbor project would increase greenhouse gas emissions.[29] Staff concluded that round trip efficiency losses would

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[24] *Id*. at 8-9.
[25] *Id*.
[26] Maillog No. 230823 ("OPC Comment") at 5.
[27] *Id*.
[28] *Id*. at 4-5
[29] *Id*. at 5-8.

result in the BGE projects increasing greenhouse gases on net, while the Pepco and Delmarva projects would, on net, still result in a decrease in emissions.[30]

15. OPC also highlighted how the level of granularity of time periods over which emissions impacts are measured (whether annually, monthly, daily, or hourly) can have a large impact on the results of such studies because of the high degree of variation in generation emissions deltas between on and off-peak hours throughout the year.[31] OPC recommended that future calculations be conducted by using data broken down by month, but that hourly data would be more useful.[32]

16. OPC noted that in the future, when there are more renewable resources on the margin in PJM, batteries will likely provide a net emissions benefit.[33] But in the near term, OPC recommended that to ensure net emissions benefits are aligned with Maryland's clean energy goals, battery projects should be paired with renewables.[34]

b. Cost Recovery

17. The Exelon Companies have proposed that for all utility-owned projects, both the capital costs and operations and maintenance ("O&M") be included in rate base and recovered in base rates, with depreciation expense and other expenses included as operating income.[35] Any PJM revenues associated with these projects during the ten-year

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[30] Staff Comment at 28.
[31] Exhibit to OPC Comment (the Synapse Report) at 7-9.
[32] *Id*.
[33] OPC stated that this will depend on at least one of three criteria being met: (1) the storage must be paired with or charged by a renewable energy source; (2) the percentage difference in marginal emissions between the hours the storage technology is charging, and discharging is greater than the RTE of the storage; or (3) the operator of the energy storage system purchases sufficient Tier I Renewable Energy Credits annually to "supply" renewable energy for the energy storage technology. *Id*. at 6-7
[34] *Id*. at 9.
[35] Hearing Transcript at 104.

term of the Pilot will be credited to customers.[36] The Exelon Companies also proposed that for all third-party owned projects, incremental O&M costs (including grid reliability payments to developers) be included in a regulatory asset to be recovered in a future rate case.[37] They argued that absent the opportunity to earn a return on incremental O&M costs for third-party owned projects, utilities are incentivized to pursue capital-intensive utility-owned projects (which earn a rate of return) rather than third-party projects funded through O&M (which does not earn a return).

18. Staff questioned the utilities' need to capitalize and earn a return on grid reliability service costs.[38] Staff otherwise supported the proposal that all costs related to energy storage Pilot projects, net of PJM revenues, be deferred in a regulatory asset with an amortization period of 15 years. Staff requested that each project be tracked separately for investments, expenses, and savings associated with the specific project.[39]

19. The Power Plant Research Program ("PPRP") also opposed the request to place certain O&M expenses for third-party owned projects, including grid reliability payments, into a regulatory asset that earns a return as part of rate base.[40] PPRP argued that the General Assembly's requirement that utilities put forth storage projects counters the Exelon Companies' argument that the Commission needs to incentivize third-party options during this Pilot program. PPRP further argued that the question of utility incentives is better addressed as part of a performance incentive mechanism in Public Conference 51 ("PC51").

[36] Exelon Companies Application at 82.
[37] *Id.*; Maillog No. 231292.
[38] Staff Comment at 75.
[39] *Id.*
[40] Maillog No. 230814 ("PPRP Comment") at 8-9.

20. OPC agreed with PPRP that the Commission need not concern itself with incentivizing projects that the General Assembly has required.[41]

21. The Maryland Energy Administration ("MEA") suggested that if a new regulatory asset is to be created, utilities should produce an accounting of the PJM revenues in order to improve understanding of potential benefits for ratepayers.[42] For utility-owned projects, MEA suggested that the credit for PJM revenues should be extended beyond the initial ten-year term to the full life expectancy of the batteries.

22. Staff also recommended that if any project's costs are ultimately "drastically different" than those contained in the utility's application, the Commission should consider that factor in determining whether to approve recovery of additional costs.[43]

23. Both the Exelon Companies and Staff also made arguments about potential cost allocation among customer classes and bill impacts.[44]

c. Contingency Projections

24. OPC expressed concern about the high contingency costs included in the proposals, although it did not find them unreasonable given that the utilities have never run projects like these before. However, OPC opposed allowing utilities to collect contingency costs as part of a multi-year rate plan ("MRP").[45]

25. MEA also expressed concern at the high level of contingency costs in the proposals from the Exelon Companies, and suggested that they may be burdensome to

[41] Hearing Transcript at 148-149.
[42] Maillog No. 230815 ("MEA Comment") at 4-5.
[43] Staff Comment at 51.
[44] Exelon Companies Application at 82; Staff Comment at 75-82.
[45] Hearing Transcript at 147-48.

ratepayers.[46] MEA proposed and that the Commission place conditions on the ability of the utilities to access contingency funds.

d. Decommissioning, Safety, and Fire Prevention

26. PPRP was concerned about fire safety and recommended that the Commission require utilities to share plans to address fires and explosions for Commission review and approval prior to installation.[47]

27. In addition, based on the toxicity of lithium ion batteries, PPRP recommended that utilities file a decommissioning plan for Commission review and approval.[48] PPRP recommended following the framework used in New York State, which requires each plan to contain a narrative description of the decommissioning process, plans for funding the decommissioning process, and contingency plans for removal of damaged batteries.[49]

e. Data Collection Metrics

28. Staff proposed additional metrics that it believes would aid in the evaluation of the Pilot projects.[50] Staff noted that, although the Working Group proposed to make electric service quality (such as voltage excursions and harmonics, which Staff proposes to call "Power Quality") a quantifiable metric, no utility has addressed the issue as such.[51] Staff also proposed that Power Quality metrics—such as the System Average RMS Variation Frequency Index, which measures "voltage sags"—be incorporated into Pilot evaluation metrics.[52] Staff recommended that the Commission reconvene the Working

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[46] MEA Comment at 2-3.
[47] PPRP Comment at 3-4.
[48] *Id*. at 4.
[49] *Id*. at 4-5.
[50] Staff Comment at 69-71
[51] *Id*. at 56.
[52] *Id*. at 56-57.

Group to more fully develop final data reporting requirements for tracking the individual value streams of each approved project.[53]

29. Staff recommended that, given the expectation that more renewables will enter the grid during the Pilot period, the utilities continue to monitor the amount of distributed energy resources ("DER") on all feeders affected by the Pilot projects, and that DER hosting capacity[54] should be included in Pilot evaluation metrics.[55]

30. Staff also noted that one advantage of a BESS is the ability to relocate the resources to new locations when more efficient deferral opportunities present themselves.[56] Staff recommended that utilities continue to keep track of whether their projects can be relocated as well as any costs of relocation.

31. Staff also raised concerns about accuracy of the number of discharge hours estimated for the Exelon Companies' projects, which may impact the calculation of certain public benefits claimed.[57]

32. OPC noted that the Exelon Companies identified several qualitative benefits for its six projects, including NOx emissions reductions, reliability and resilience, grid operational flexibility, and distributed generation hosting capacity.[58] OPC recommended that the Commission require the utilities to quantify these benefits when they file annual reports, under PUA § 7-216(h)(7)(i), or explain why they cannot.

[53] Hearing Transcript at 202.
[54] Defined in COMAR 20.50.09.02.
[55] Staff Comment at 59.
[56] *Id*. at 64.
[57] *Id*. 26-30.
[58] OPC Comment at 5.

f. Other General Concerns

33. PPRP was concerned that the projects need to comply with federal, state, and local requirements, which ordinarily are addressed during the Certificate of Public Convenience and Necessity ("CPCN") process, but which is not required for these projects.[59] While PPRP did not recommend a CPCN process for the Pilot projects, it does recommend that the Commission condition any approvals on compliance with applicable law.[60]

34. MEA was also concerned about the timeline for sunsetting this Pilot and suggested that, in the event of any delays, the data collection required under PUA § 7-216 be extended to provide as much information as possible.[61]

2. Proposed Energy Storage Project #1: BGE's Fairhaven Project

35. BGE's first proposed project is a utility-owned and operated lithium ion BESS located at BGE's Fairhaven substation, in Anne Arundel County, Maryland.[62] The Fairhaven proposal calls for 2.5 MW/7.1 MWh of initial usable capacity, though the capacity is projected to degrade to 4 MWh over the useful life of the batteries.[63]

36. The primary goal of the Fairhaven project is to improve distribution system reliability, and BGE anticipates that the system will help with winter peak demand to mitigate contingency overload.[64] Secondarily, the project will also participate in PJM markets, providing frequency regulation.

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[59] PPRP Comment at 3.
[60] Maillog No. 231189.
[61] PPRP Comment at 3.
[62] Exelon Companies Application at 14-18.
[63] *Id*. at 15.
[64] *Id*. at 15-16.

37. Ultimately, BGE concluded that the Fairhaven project will have a 1.3 benefit-to-cost ratio.[65]

a. Staff Comment

38. Staff concluded that the Commission could approve the Fairhaven project because it was the most cost-effective of the utility-owned and operated projects. However, Staff also raised concerns with BGE's cost-benefit analysis.[66]

39. As referenced above, Staff explained that, although some of the Exelon Companies' proposals included projected reinvestments in future storage projects to account for deterioration and new conditions,[67] Staff approached its own valuation of all projects by assuming that all value streams end after 10 years, with any deferred distribution investments taking place at that time, and that costs will be amortized over 15 years.[68] This had the effect of reducing the projected cost-effectiveness of the Fairhaven project to the point where it was not cost-effective.

40. Staff also challenged BGE's inclusion of "optionality" benefits, which Staff argued are possibly inappropriate.[69] Staff also highlighted $800,000 in O&M costs potentially omitted from BGE's analysis, which would further lower the cost-benefit value.[70]

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[65] *Id*. at 25. BGE's explanation of how it reached this result is detailed at pages 25-32.

[66] Staff Comment at 14. Staff summarized a comparison of its and the Exelon Companies' cost-benefit analyses in Attachment A, at page 85. Data from that comparison is referenced in this Order, but the tables are not reproduced.

[67] During the hearing, BGE explained that it presented projections covering 30 years because that was the lifespan of the projects whose costs would be deferred or displaced. Hearing Transcript at 25.

[68] Staff Comment at 8. Staff found that this issue affects both BGE projects and the Pepco Montgomery County project, discussed below.

[69] Staff Comment at 13-14.

[70] *Id*. at 14.

41. Despite those concerns, Staff still found that the project might be cost-effective if the project was permitted to operate in perpetuity, rather than the original ten-year projection, though this would require an amendment to the PUA.[71]

b. OPC Comment

42. OPC recommended that the Commission approve the Fairhaven project and had no concerns specific to this installation.[72]

3. Proposed Energy Storage Project #2: BGE's Chesapeake Beach Project

43. BGE's second proposed project is a third-party owned and operated lithium ion BESS located at Chesapeake Beach.[73] The project is to be owned and developed by Ameresco, which has identified four potential sites within the distribution system. BGE states that it and Ameresco will work together to finalize the location. BGE and Ameresco will enter into a ten-year pay-for-performance contract for grid reliability services.[74] The total cost is projected to be $1.9 million in present value ($2.5 million total), not including contingency funds.[75]

44. The proposal calls for a 2.0 MWh initial capacity.[76] The primary goal of the proposal is to improve reliability during peak winter usage. The BESS will also participate in PJM markets during other periods, including frequency markets and energy arbitrage. PJM revenues for the project would flow through to Ameresco's account, but

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[71] Staff Comment at 14.
[72] OPC Comment at 4-5.
[73] Exelon Application at 19-24.
[74] *Id*. at 19.
[75] *Id*. at 21-22.
[76] *Id*. at 19-20.

BGE would receive a percentage of project-associated revenues above a certain threshold. BGE concluded that the project will have a 1.98 benefit-to-cost ratio.[77]

a. Staff Comment

45. Staff found that the Chesapeake Beach project may be cost-effective, depending on whether BGE's proposed optionality benefit was included.[78] Staff noted, however, that the Chesapeake Beach and Fairhaven projects are deferring a single distribution need and must be considered together. Staff recommended approving the Chesapeake Beach project only if the Commission also approves the Fairhaven project.

b. OPC Comment

46. OPC recommended that the Commission approve the Chesapeake Beach project and had no concerns specific to this installation.[79]

4. Proposed Energy Storage Project #3: Pepco's National Harbor Project

47. Pepco's first proposed project is a lithium ion BESS in National Harbor, Maryland.[80] The proposal calls for a utility-owned but third-party operated BESS facility on property already owned by Pepco. The project is projected to have a 1.00 MW/3.0 MWh capacity throughout its usable life, with an initial capacity of 1.05 MW/4.25 MWh.[81]

48. Pepco expects the project to create value primarily by deferring the need for a new substation, as well as providing peak shaving and grid reliability improvements.[82]

[77] *Id*. at 25. BGE's explanation of how it reached this result is detailed at pages 25-32.
[78] Staff Comment at 15.
[79] OPC Comment at 5.
[80] Exelon Companies Application at 61.
[81] *Id*. at 63.
[82] *Id*. at 61-67.

The BESS is expected to participate in PJM markets, with revenues shared between Pepco and the third-party operator, A. F. Mensah, Inc. Pepco calculated that the National Harbor project will have a 2.34 benefit-to-cost ratio.[83]

a. Staff Comment

49. Staff concluded that the National Harbor project is close to cost-effective, although Staff was concerned that the project's cost-effectiveness depends heavily on the high cost of a distribution upgrade (a new substation) that is forecasted to be needed by 2027 (outside the Pilot study timeframe), but which may ultimately not be needed if forecasted demand increases do not materialize.[84] Staff also noted that the forecasted distribution upgrade is two years in the future, leading to the possibility that capital will be deployed years before it will be needed. Staff further noted that Pepco's analysis of cost-effectiveness depends on the installation of additional storage in 2027, which barring any extension is after the end of the Energy Storage Pilot. Staff removed this future installation from its own analysis because it is outside of the pilot period.

50. Ultimately, Staff recommended that the Commission reject the National Harbor project and requested that Pepco propose another project that serves a need during the Pilot's timeframe and does not risk premature investment of capital.[85] Alternatively, Staff proposed that Pepco expand the National Harbor project to defer the entire distribution upgrade beyond three years, although this would require special exemptions from the existing Pilot framework.

[83] *Id*. at 68. Pepco's explanation of how it reached this result is contained on pages 66-70
[84] Staff Comment at 18-19.
[85] *Id*. at 82.

b. OPC Comment

51. OPC recommended approval of the National Harbor project and had no concerns specific to this installation.[86]

5. Proposed Energy Storage Project #4: Pepco's Montgomery County Project

52. Pepco's second proposed project is a lithium ion BESS at a bus depot in Silver Spring, Maryland.[87] The BESS will be owned and developed by AlphaStructure, and Pepco will have the contractual right to use 3 MWh over a 3 hour period up to 10 days per year over a 10 year period. Pepco will have the option to extend the contract to 15 years.[88]

53. The proposed project would defer, and potentially avoid, an estimated $3.6 million feeder upgrade otherwise necessary to serve an electric bus depot owned and developed by the Montgomery County Government.[89] The BESS would provide peak shaving and back-up power during emergency grid conditions. Pepco estimated the project's 15-year incremental costs at $2.478 million.[90] Pepco also estimated the project's present value benefits at $4.794 million, for a total benefit-cost ratio of 1.93. Pepco also projected a number of unquantified benefits, including that the batteries will sometimes be charged by solar photovoltaic arrays at the site.[91]

[86] OPC Comment at 7.
[87] Exelon Companies Application at 70.
[88] *Id*. at 74.
[89] *Id*. at 71.
[90] Pepco's cost and benefit estimates are contained in the Exelon Companies Application at 76-79.
[91] *Id*. at 80-81.

a. Staff Comment

54. Staff recommended that the Commission approve the project, finding that it is cost-effective and advances the public interest by supporting the use of electric vehicles and providing insight into the interaction between energy storage and electric vehicles.[92]

b. OPC Comment

55. OPC recommended that the Commission approve the Montgomery County project. However, OPC recommended the Commission require that the battery charge primarily from the facility's solar panels or the grid and that natural gas generator charging be used only as a last resort.[93]

6. Proposed Energy Storage Project #5: Delmarva's Elk Neck Project

56. Delmarva's first proposed project is a virtual power plant ("VPP") to be located at Elk Neck State Park in Cecil County, Maryland.[94] The proposal calls for Delmarva to contract with Sunverge Energy, which would purchase behind-the-meter energy storage systems to be installed in 110 homes in Elk Neck.[95] Those systems would then be networked together to allow them to operate as a virtual power plant capable of providing 0.5 MW/1.5 MWh of aggregated capability.[96] Participating homeowners would receive ownership of the equipment after a ten-year contract period.[97]

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[92] Staff Comment at 83.
[93] OPC Comment at 8.
[94] Exelon Companies Application at 35.
[95] In response to concerns discussed below, at the hearing Delmarva representatives stated that Delmarva set the number of homes in order to ensure that, with attrition, there were enough participants over the whole project length to fully evaluate the project.
[96] Exelon Companies Application at 37.
[97] *Id*. at 40.

57. The BESS is projected to improve reliability by providing peak shaving and assisting the grid during emergency events.[98] When not in use for those purposes, the residents would also benefit from the use of the system for personal back-up power, coordination with solar arrays, and for taking advantage of time-of-use rates.[99] Delmarva is also looking into whether the project would be able to participate in PJM markets.

58. In response to stakeholder concerns, Delmarva stated that it selected Elk Neck because, unlike other options like Ocean City, the location has year-round demand, is primarily single-family housing stock (multi-family created practical issues for in-home battery storage), and because the area has frequent power outages.[100]

59. Delmarva projected that the project will have a $3.5 million cost in present value over a 10-year term, but would only provide benefits of $1.2 million in present value over a 15-year term, for a benefit-to-cost ratio of approximately 0.3, not including the value of unquantified benefits.[101]

a. Staff Comment

60. Staff found that the Elk Neck project has the worst cost-benefit return of all proposed projects and should only be approved in the interest of studying the VPP model.[102]

61. Staff also recommended that the Commission only approve the Elk Neck project if Delmarva secures an agreement with PJM to allow the project to participate in PJM

[98] *Id*. at 38.
[99] *Id*.
[100] Hearing Transcript at 49.
[101] *Id*. at 37 and 44. Delmarva has provided a more detailed explanation of costs and benefits in its application at pages 41-47.
[102] Staff Comment at 16.

markets.[103] Staff stated that it was concerned that approximately half of the benefits projected for the Elk Neck project come from PJM revenues, even though PJM does not yet generally allow virtual power plants to bid into its markets, although that possibility is expected to be considered by PJM in 2021.

b. OPC Comment

62. OPC recommended that the Commission approve the Elk Neck project because it is the only VPP project being considered, though OPC was concerned about the poor return on investment.[104]

63. OPC recommended that Delmarva restructure the Elk Neck project to seek to include customers who already have solar PV systems installed in their homes, which OPC claims would reduce emissions and be educational for the future of the industry.[105] OPC also recommended that Delmarva seek to coordinate its other offerings (such as EmPOWER, direct load control, and time-of-use rates) to create additional benefits. At the hearing, Delmarva represented that it already planned to pursue these enhancements.[106]

c. PPRP Comment

64. PPRP expressed concern about the uncertainty of the Elk Neck VPP being able to participate in PJM markets and suggested that Delmarva consider other locations with feeder constraints, such as Chestertown or Trappe.[107]

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[103] *Id*. at 82.
[104] OPC Comment at 6.
[105] *Id*. at 5.
[106] Hearing Transcript at 51.
[107] PPRP Comment at 13.

65. PPRP also took issue with the cost-allocation proposal for the Elk Neck project, which would socialize the costs of the project across the utility's service territory.[108] PPRP noted that a large share of the benefits of the project as proposed would accrue not to ratepayers generally, but to the specific homeowners selected for participation in the project. If the Elk Neck project is approved, PPRP recommended that participants be required to pay for a portion of the benefits they receive. At the hearing, Delmarva represented that it decided not to seek participant contribution because of the need to obtain a large number of participants quickly, the fact that participants were expected to incur certain other costs as a result of participation, administrative costs, and the desire to include low-income groups in the Pilot.[109]

d. MEA Comment

66. MEA expressed concern that there was not enough clarity about how the utility set the specific number of storage systems (110) in light of the high individual costs of each installation.[110] MEA also suggested further investigation into disaggregated costs in order to inform future VPP project proposals. At the hearing, Delmarva responded that it set the number of systems based on its projections of how many would be needed to produce enough data to meet the research purposes of this Pilot, given estimated customer attrition from the program.[111]

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[108] *Id*. at 6-7.
[109] Hearing Transcript at 54-56.
[110] MEA Comment at 4.
[111] Hearing Transcript at 49-50.

7. Proposed Energy Storage Project #6: Delmarva's Ocean City Project

67. Delmarva's second proposed project is a utility-owned and operated lithium ion BESS in Ocean City, Maryland.[112] The BESS is planned to have 1.0 MW/3.6 MWh in initial capacity.

68. The BESS is projected to provide peak shaving capability, improved reliability, and to aid during emergencies.[113] The BESS is also expected to participate in the PJM frequency regulation market.

69. Delmarva projected that this project would have a $5.3 million cost—in present value—over 15 years but produce only $2.6 million—in present value—in benefits over that same term, for a total benefits-to-cost ratio of approximately 0.45, although Delmarva identified a number of unquantified benefits it hopes will allow the project to be cost-effective.[114]

a. Staff Comment

70. Staff found that the Ocean City project has a low cost-benefit ratio and recommended that the Commission deny the project if it chooses to approve BGE's Fairhaven project because both projects test the same business model, but the BGE projects are more cost-effective, and the Ocean City project does not defer a planned distribution system upgrade.[115]

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[112] Exelon Application at 47-48.
[113] *Id*. at 48-49.
[114] *Id*. at 49, 56, and 58. Delmarva's more detailed explanation of costs and benefits are contained at pages 52-58.
[115] Staff Comment at 17, 82.

b. OPC Comment

71. OPC recommended that the Commission approve the Ocean City project and had no concerns specific to this installation.[116]

c. PPRP Comment

72. PPRP expressed concern that the Ocean City project will require careful coordination of its charging and discharging schedule in order to enable it to achieve all of the projected reliability and resiliency benefits, which may not be compatible at all times.[117] At the hearing on July 13, 2020, Delmarva explained that it would charge prior to the time of expected use (anticipating that usage during storm emergencies would be somewhat predictable), thereby providing added reliability and resilience during critical periods.[118]

Commission Determination

73. PUA § 7-216(h)(ii) provides that the "Commission shall approve, approve with modifications, or reject an application submitted under subsection (d) of this section after: (1) receiving comments from the Maryland Energy Administration, the Office of People's Counsel, and other stakeholders and holding a hearing; (2) considering the projected costs and benefits of the projects proposed for inclusion in the Pilot program; and (3) determining whether the project is in the public and ratepayer interest."

74. The Commission has received the required stakeholder comments and held a public hearing on July 13, 2020. The Commission has also considered the competing arguments on the costs and benefits of the individual project proposals. Based on the

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[116] OPC Comment at 6-7.
[117] PPRP Comment at 15-16.
[118] Hearing Transcript at 71-72.

considerations required under PUA § 7-216, the Commission finds that the six Exelon Companies' projects are in the public and ratepayer interest and are approved, subject to the comments and conditions below.

75. The Commission notes, as in the concerns raised by some stakeholders, that some of the projects might not be immediately cost-effective, although the value of some benefits remains unquantified. The Commission also notes the special concerns raised by Staff regarding the extended time horizon of the National Harbor project, which may necessitate an extension of this Pilot project's reporting requirements.

76. At the same time, this pilot program's value to both ratepayers and the public will come primarily from the lessons learned by utilities, stakeholders, and the Commission, and which will later be relied on in making future investment decisions. Toward that end, the Commission notes that the six projects being approved satisfy all four ownership models anticipated by PUA § 7-216 and appear well constructed to produce valuable data and experience that will form the foundation for the next phase of utility-scale energy storage in Maryland.

77. Separately, the Commission finds that given Potomac Edison's request that the Commission deny its Little Orleans proposal, the Little Orleans proposal is not in the public and ratepayer interest at this time. The Commission also finds that there is a strong interest in considering both of Potomac Edison's project proposals together. The Commission therefore will defer issuing a decision on Potomac Edison's Town Hill proposal until such time when Potomac Edison's second proposal is filed.

1. Contingency Projections

78. Several parties raised concerns regarding the large amount of contingency funding included in the projected costs of the Exelon Companies' six projects. Given that this is a pilot program for a type of project that the companies are not familiar with, the Commission finds that the contingency funding levels are reasonable. The Commission is also cognizant of its duty to protect ratepayer resources and the need to incentivize the utilities to adopt the industry's evolving best practices for promoting efficiency in developing energy storage projects. Therefore, in the event that a utility anticipates it will need to expend more than 50% of the approved contingency funding, the utility must notify the Commission, explain the reason(s) the original funding projection was inadequate, and describe the steps the utility is taking to contain cost overruns. The Commission will address any request to collect unexpended contingency funding in a future rate case.

2. PJM Market Participation

79. **Most** of the approved project proposals **are** premised on a revenue stream from participation in PJM markets. PUA § 7-216(g) states, in pertinent part, that the Commission may, on a project-by-project basis, allow an energy storage device owned or operated by an investor-owned electric company to participate in all available PJM wholesale electricity markets in order to capture additional revenue for the benefits for ratepayers.

80. Based on that authority, the Commission finds that the approved projects **premised on participation in PJM wholesale markets** must **do so**. As a condition of approval for each **such** project, the utility must certify to the Commission by February 1,

2021 that the project meets all technical specifications and performance standards for participation in PJM markets.

81. Additionally, given the uncertainty associated with Delmarva's Elk Neck project's ability to participate in the PJM markets, the company must certify to the Commission that it has reached an agreement with PJM to allow the Elk Neck VPP to participate in PJM markets prior to beginning installation.

82. In the event that a utility becomes aware that a given storage project fails to meet these conditions and cannot participate in the PJM markets, the utility must notify the Commission immediately.

3. Recovery of O&M Costs

83. PUA § 7-216(f) provides that, for purposes of the Pilot program only, the Commission may determine how to address cost recovery for third-party owned projects and virtual power plants.

84. The Commission notes the Exelon Companies' concerns that, given the choice between utility-owned and third-party owned storage solutions, a difference in financial treatment between the two may incentivize utilities to make self-interested investment decisions that are sub-optimal from the perspective of ratepayers and overall system efficiency. The Commission finds, however, that the Exelon Companies' proposal to allow a return on certain O&M costs for third-party owned projects is unnecessary at this time, and that a decision on how to address factors that might affect future storage projects will be better informed following the completion of this Pilot. Accordingly, standard cost recovery rules will apply for O&M costs attributable to the use of third-party owned assets under this Pilot. Utilities may, however, track capital and O&M

spending within a regulatory asset, with investments and expenses tracked separately for each project. The Commission will also address proposals regarding amortization periods in a utility's future rate case.

4. Cost Allocation

85. Although some parties have raised questions about cost allocation for individual projects that benefit specific customers, the Commission will address cost-allocation as part of any rate case in which a utility seeks to recover costs incurred as part of this Pilot.

86. As to PPRP's proposal that the Elk Neck VPP participants share in the costs of that project, the Commission agrees that the benefits that will accrue to ratepayer participants are substantial. Nonetheless, the Commission declines to impose a cost-sharing framework, given the need to develop the project quickly for purposes of this Pilot.

5. Emissions Management and Tracking

87. Understanding how a BESS can align with and support Maryland's clean energy and greenhouse gas reduction goals is an important objective of the Pilot. The evidence and testimony highlight two important limitations to the emissions projections presented by the utilities and the approach taken by the Energy Storage Working Group. The first concerned the need for more granular tracking of the impact of storage on emissions to account for a high degree of variance throughout the year. The second concerned the reality that, under current technology, battery storage suffers substantial round-trip energy losses from charging, storage, and discharging cycles, which can reduce efficiency and have the effect of increasing total greenhouse gas emissions.

88. As a condition of approval, the utilities are directed to file by February 1, 2021 an emissions management plan for each project. Each plan shall include revised projections for the impact on emissions by each project using monthly historical emissions data.

89. Additionally, PUA § 7-216(h)(6) requires utilities to provide, on or before certain dates, information about emissions reductions, and § 7-216(h)(7) requires utilities to provide "any other information required by the Commission." Pursuant to that authority, the Commission directs the utilities to collect and produce hourly data tracking charging and discharging periods and amounts; historic hourly emissions for each charging and discharging period; round-trip losses over time; and an estimate of any resulting increased emissions caused by each project throughout the life of the Pilot.

6. Decommissioning, Safety, and Fire Prevention

90. Utility-scale battery storage comes with risks both in terms of safety and environmental contamination. As a condition of approval, the utilities are directed to file, by February 1, 2021, plans for preventing and addressing fires and explosions, for safe removal of damaged batteries, and for decommissioning and disposal of batteries. Plans shall contain a narrative description, an estimate of costs, and identify the source of funding. The plans will be subject to Commission approval.

91. Since the Elk Neck project is unique because it involves the installation of energy storage systems in private residences, the Commission finds that additional care and evaluation of risks is warranted. Accordingly, Delmarva is directed to address in its report any safety concerns associated with installing storage resources in customer homes, and its plans for informing potential participants of those risks.

7. Data Collection Metrics

92. In addition to data and information required to be tracked by PUA § 7-216(h)(7), both the Working Group in its December 31, 2019 report and Staff proposed additional metrics that the utilities would track and report. The Working Group Report also anticipated that some value streams may be difficult to quantify, a theme repeated in the Exelon proposals—which project unquantified benefits of indeterminate size.

93. The Commission will not make findings on these additional metrics at this time. However, the Commission directs the Working Group to reconvene to develop an updated recommendation on data collection, metrics, and related Pilot parameters for each project approved in this order. For presently unquantified value streams, the Working Group should propose realistic metrics in anticipation of improved valuation methods in the future. That recommendation should be filed no later than March 31, 2021.

8. Proposals to Extend the Pilot

94. Some parties have already raised the question of extending the period of the Pilot program. PUA § 7-216 provides that: "if an investor-owned electric company determines that additional time to gather data would provide additional opportunities for learning and justify continuing the Pilot program, the Commission may extend the Pilot program and delay by a corresponding amount of time the evaluation and report required under subsection (k) of this section."

95. Given the long window of time between now and the scheduled termination of the Pilot program—currently December 31, 2026—and the fact that all projects are projected to continue operating well past that point, the Commission will address the question of

any extensions of the Pilot and associated reporting requirements once the projects are operational and data collection has begun.

9. Utility Compliance with State and Local Requirements

96. Although there has been some question regarding the procedure the Commission should follow to ensure that the utilities fully comply with State and local requirements, which for capital projects are often addressed via the CPCN process, PUA § 7-216 does not require that process but instead created a separate public hearing and comment process, which the Commission has followed. Nonetheless, as a condition of approval, all Pilot projects must comply with State and local laws.

IT IS THEREFORE, this 6th day of November, in the year of Two Thousand Twenty, by the Public Service Commission of Maryland;

ORDERED: (1) The Energy Storage Pilot projects proposed by the Exelon Companies are approved, subject to the conditions contained in this order;

(2) The Little Orleans Energy Storage Pilot project proposed by The Potomac Edison Company is rejected.

/s/ Jason M. Stanek

/s/ Michael T. Richard

/s/ Anthony J. O'Donnell

/s/ Odogwu Obi Linton

/s/ Mindy L. Herman
Commissioners