ERRATA FILING OF APRIL 3, 2025

**BEFORE THE**
**PUBLIC SERVICE COMMISSION**
**OF MARYLAND**

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| MARYLAND ENERGY STORAGE PROGRAM | Case No. 9715 |

**COMMENTS OF THE MARYLAND OFFICE OF PEOPLE'S COUNSEL ON UTILITY PROCUREMENT PROPOSALS**

The Office of People's Counsel has reviewed the energy storage procurement proposals filed by Baltimore Gas and Electric Company ("BGE"), Delmarva Power & Light Company ("DPL") and Potomac Electric Power Company ("Pepco") (collectively, the "Exelon utilities")[1] and The Potomac Edison Company ("Potomac Edison")[2] in response to Commission Order No. 91495, which directed Maryland's investor-owned electric companies to propose cost-effective energy storage procurements to support the initial Maryland Energy Storage Program ("MESP") goal of 750 megawatts ("MW") of energy storage capacity by May 31, 2028.[3]

Based on our review of these filings, OPC makes the following recommendations:

1. The Commission should deny both the Exelon utilities' proposal to procure utility-owned transmission-connected energy storage devices ("ESD") and the

[1] Request for Approval of Energy Storage Procurement Proposal, *Maryland Energy Storage Program* (CN 9715 Feb. 21, 2025) ML 316129 [hereinafter "Joint Exelon Proposal"]; Request for Approval of Energy Storage Procurement Proposal, *Maryland Energy Storage Program* (CN 9715 Feb. 21, 2025) ML 316131 [hereinafter "Exelon-SEIA Proposal"].
[2] Request for Approval of Energy Storage Procurement Proposal, *Maryland Energy Storage Program* (CN 9715 Feb. 21, 2025) ML 316132 [hereinafter "Potomac Edison Proposal"].
[3] Public Utilities Article § 7-216.1 [hereinafter "PUA"].

utilities' proposal to procure utility-owned distribution-connected ESDs located on customer properties. On one hand, the Exelon utilities have not demonstrated that utility ownership of either type of storage asset would provide unique benefits to customers. On the other hand, allowing utility ownership of such assets would impede the development of competitive markets for storage assets and services and could expose customers to greater risks.

2. Given the paucity of details in the proposals of both the Exelon utilities and Potomac Edison to procure third-party-owned transmission- and distribution-connected ESDs, the Commission should defer approval of those proposals pending the utilities' submission of further compliance filings that include benefit-cost analyses, bill impact analyses, and other information the Commission needs to assess the affordability and equity impacts of the proposed procurement mechanisms, with the goal of ensuring that procurements will result in net benefits to utility customers.
3. The Commission should require both the Exelon utilities and Potomac Edison to include in their compliance filings detailed budgets based on current and adequate information. The Exelon utilities' procurement proposals include no budgets, while Potomac Edison's proposed $28 million budget cap is based on limited and outdated information regarding a single pilot project.
4. The Commission should direct the Exelon utilities to provide a detailed plan for the development and implementation of the distributed energy resource

management Systems ("DERMS") discussed in their proposal. The plan should, at a minimum, explain the Exelon utilities' current distributed energy resource ("DER") management and control capabilities and the specific uses that the companies intend for their DERMS systems. The plans should also provide a timeline for bringing their DERMS systems into operation.

5. With respect to the Exelon utilities' proposal to procure third-party owned transmission-connected energy storage through 15-year, full-tolling procurements in which the utilities would make fixed payments to developers to build and interconnect projects, then be responsible for bidding the projects into PJM's wholesale markets and securing PJM revenues, the Commission should:

    a) Direct the utilities to provide benefit-cost analysis for procurement through partial-tolling agreements as a point of comparison to the utilities' full-tolling agreement BCA.

    b) If the Commission should authorize the use of full-tolling agreements, deny the utilities' proposal to retain 30 percent of annual wholesale revenues above levelized contract and implementation costs, or in the alternative require the utilities to bear some of the risk that contract and implementation costs will exceed wholesale revenues. Under the utility-proposed framework proposed in their filings, the risk of annual wholesale market revenues being lower than annualized contract costs would be borne entirely by ratepayers.

6. The Commission should require Potomac Edison to file a transmission-connected third-party owned procurement program that aligns with the recommendations above regarding the Exelon utilities' program.
7. The Commission should defer approval of cost recovery mechanisms for transmission-connected battery storage projects until after the Commission approves project costs. The Commission should generally require utilities to expense all operating and maintenance costs in the year they are incurred but should consider amortizing the costs of the initial years of the projects if expensing the costs entirely in the first year would impose unreasonable costs on utility customers.

    a. Regarding the Exelon utilities' proposal, the Commission should either deny the use of regulatory assets to recover tolling agreement costs and instead require the utilities to expense those costs in the years they are incurred or—if the Commission authorizes the use of regulatory assets—determine that the return on assets used to recover tolling agreement costs shall not exceed the utilities' cost of debt. Because tolling agreement costs are not capital expenditures, they should not be recovered at the utilities' weighted average cost of capital (WACC). Either of these alternative cost recovery mechanisms will avoid the unjustified profits on non-capital expenditures and unnecessary customer bill impacts.

    b. Regarding the Potomac Edison proposal, while expensing costs is generally protective of ratepayer interests, the Commission should defer approving expensing costs annually until a final estimate of project costs is approved. In the event that expensing project costs would result in a shock to ratepayers, the Commission should consider amortizing the costs over an appropriate time period and allowing Potomac Edison to recover carrying costs at the average cost of debt.

## BACKGROUND

On May 8, 2023, the Maryland General Assembly enacted House Bill 910, codified at PUA § 7-216.1, directing the Commission to establish the MESP and setting targets for cost-effective energy storage deployment.[4] The statue requires that MESP include "competitive procurement mechanisms to reach a minimum of 3,000 MW of energy storage, or the maximum cost-effective amount of energy storage that can be deployed by [May 31, 2034]".[5]

On December 2, 2024, the Exelon utilities and Solar Energy Industries Association ("SEIA") jointly filed a proposal for a competitive procurement of 40 MW of third-party owned, front-of-the-meter ("FTM") distribution-connected energy storage.[6]

Based on the statutory requirement that MESP include a competitive procurement and the joint Exelon-SEIA proposal, the Commission issued Order No. 91495 on January 22, 2025, establishing a "narrow-scope" proceeding to determine a cost-effective energy storage procurement allocation toward the first MESP goal of 750 MW of energy storage

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[4] Act of May 8, 2023, ch. 570, Md. Laws (codified at PUA § 7-216 to 7-216.1).
[5] PUA § 7-216.1(c)(3)
[6] Exelon-SEIA Proposal (CN 9715 Feb. 21, 2025) ML 316131.

capacity by May 31, 2028.[7] The Order directed investor-owned electric companies to propose an initial set of cost-effective energy storage procurement mechanisms, along with "a prospective timeline through expected commercial operation, the amount of energy storage procurement, and other factors addressed in the MESP WG Phase 1 Final Report necessary to inform a Commission decision on energy storage procurement allocations."[8] The Commission invited the Exelon utilities and SEIA to re-file their joint proposal to meet these requirements.

On February 21, 2025, the Exelon utilities filed two procurement proposals: (1) a joint Exelon utility filing that outlines a broad range of procurement mechanisms described in detail below, and (2) a revised version of the FTM, distribution-connected procurement proposal that the Exelon utilities and SEIA filed in December 2024.

The Exelon utilities request that the Commission approve a varied set of transmission- and distribution-connected procurement mechanisms. Some of the distribution-connected storage that the Exelon utilities propose to procure would be located in front of the customer meter ("FTM"), while some would be behind the meter ("BTM").

***Exelon utilities' proposed distribution-connected procurement mechanisms***

At the distribution-connected level, the Exelon utilities propose the following procurement mechanisms, which are summarized in Table 1 below:

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[7] Case No. 9715, Order No. 91495, Order Initiating Maryland Energy Storage Procurement Proceedings (January 22, 2025).

[8] *Id.*at 4. The Commission noted that "[f]uture proceedings in this docket will expand the scope to consider additional mechanisms and initiatives needed to meet energy storage capacity goals, pending receipt of MESP WG recommendations from its Phase II efforts or as otherwise needed." *Id.*

1. **Utility-owned FTM:** The Exelon utilities state that they can deploy FTM projects to meet local distribution system needs and avoid system upgrades and note that BGE is currently deploying its Distributed Battery Energy Storage System ("DBESS") program. The Exelon utilities state that because these projects are subject to normal rate case cost recovery and review, the Exelon utilities have no request from the Commission, except for an acknowledgement of the importance of these procurement mechanisms.[9]
2. **Third-party owned FTM:** The Exelon utilities request Commission approval for a 150 MW statewide distribution-connected storage procurement, with separate competitive solicitations for utility-owned and third-party-owned FTM energy storage and each procurement mechanism accounting for at least 30 percent of the total target. The Exelon utilities recommend that the Commission establish a budget and cost recovery mechanism incremental to existing approved utility budgets and multi-year plans. This procurement mechanism noted in the filing is made solely by the Exelon utilities and described in more detail in the revised Exelon-SEIA filing.[10]

[9] Joint Exelon Proposal at 7 (CN 9715 Feb. 21, 2025) ML 316129.

[10] The revised Exelon-SEIA filing differs from the original version of the filing primarily in that the original version provided for the procurement of 40 MW of FTM, distribution-connected storage, all of which would be owned by third parties, while the revised version provides for the procurement of 150 MW of FTM, distribution-connected storage, some of which would be owned by the utilities and some of which would be owned by third parties. The Exelon utilities propose that neither ownership category may exceed 30 percent of the total storage capacity procured. *See* Joint Exelon Proposal at 7 (CN 9715 Feb. 21, 2025) ML 316129; Exelon-SEIA Proposal (CN 9715 Feb. 21, 2025) ML 316131.

3. **Commercial and industrial ("C&I") customer-sited FTM and BTM:** The Exelon utilities propose using a utility-owned, customer-sited distributed capacity procurement ("DCP") framework. Under this model, the Exelon utilities would develop utility-owned storage assets on the properties of commercial and industrial host customers, then dispatch and control the resources. The Exelon utilities do not provide details on how they will dispatch storage assets under this procurement mechanism, but claim that it can help alleviate congestion, provide resiliency, and/or defer expensive grid upgrades. The Exelon utilities state that they will identify areas of need via a locational cost-benefit analysis to determine areas of need for cost-effective deployment and will work with stakeholders and an implementation partner to conduct this analysis if the Commission approves the DCP proposal.

4. **Residential BTM:** The Exelon utilities propose a "subscriber" model, whereby batteries would be located on the properties of residential customers and the Exelon utilities would own, dispatch, and maintain the batteries. The utilities state that "at minimum" they would dispatch the batteries to provide load management through PJM's demand response market, and that storage devices will also be able to provide backup power for the subscriber.[11] The customer would incur a monthly subscriber fee over a 10-year term, in exchange for

[11] Joint Exelon Proposal at 10 (CN 9715 Feb. 21, 2025) ML 316129.

which the customer may benefit from reduced power costs,[12] and that after this term the customer would gain ownership of the equipment.

**Table 1. Summary of the Exelon utilities' distribution-connected energy storage procurement proposals**

| | Utility-Owned | 3rd Party-Owned | Utility-Sited | Customer-Sited | FTM | BTM | Potential Battery Sizes |
|---|---|---|---|---|---|---|---|
| 1. Utility Distribution-Connected | X | | X | | X | | 500kW |
| 2. 3rd Party Distribution-Connected | | X | | X | X | | 1-3MWs |
| 3. Commercial/Industrial Customer-sited | X | | | X | X | X | 500kW-1MW |
| 4. Residential Behind-the-Meter | X | | | X | | X | 10-15kW |

*Source: Exelon MD Utilities Request for Approval*[13]

***Exelon utilities' transmission-connected procurement mechanisms***

At the transmission-connected level, the Exelon utilities propose the following procurement mechanisms, which are summarized in Table 2 below:

1. **Utility-owned:** The Exelon utilities support utility-owned transmission-connected energy storage. They state that utilities in vertically integrated states can own storage, and mention California's new cost allocation mechanism for utilities to track and recover the net cost of new capacity resources that are owned or contracted by distribution utilities to support resource adequacy needs as an example of utility storage ownership in a deregulated state.

[12] The Exelon utilities state that "the utility will maintain access and control for the purpose of reducing power costs for the subscriber and other customers on a utility's system." *Id.* at 10. It is not clear from this statement how the reduction in power costs for the customer hosting a storage asset may differ from the cost reductions for other customers.
[13] *Id.* at 2.

2. **Third-party owned:** The Exelon utilities propose full-tolling agreements with 15-year terms. The utilities would pay the project developer an annual contract cost; in exchange, the Exelon utilities would obtain full control of battery operations to participate in the energy, capacity, and ancillary services, markets run by regional transmission operator PJM Interconnection, LLC and receive all wholesale market revenues. The Exelon utilities would then return 100 percent of revenues to customers up to the annual levelized contract costs. The Exelon utilities propose that if wholesale market revenues are greater than annual contract costs, the utilities would retain 30 percent of annual revenues that exceed the levelized contract cost and return the remaining 70 percent to customers. The utilities propose to defer annual contract and program implementation costs to regulatory assets, to move those regulatory assets into rate base in their base rate cases, and to amortize the regulatory assets over five-year schedules.

**Table 2. Summary of Exelon utilities' transmission-connected energy storage procurement proposals**

| | Utility-Owned | 3rd Party-Owned | Utility-Sited | Customer-Sited | FTM | BTM | Potential Battery Sizes |
|---|---|---|---|---|---|---|---|
| 1. Utility Transmission-Connected | X | | X | | X | | 100MW+ |
| 2. 3rd party Transmission-Connected | | X | | X | X | | 100MW+ |

*Source: Exelon MD Utilities Request for Approval*[14]

[14] *Id.*

***Potomac Edison's distribution-connected storage procurement mechanism***

Potomac Edison proposes a 6 MW third party-owned distribution-level energy storage program, with a budget cap of $28 million.[15] The company states that its initial limited procurement mechanism is designed to target areas where grid benefits can be clearly quantified and allow Potomac Edison to determine specific appropriate locations and project characteristics for cost-effective deployment. The 6 MW program can either be met through a combination of individual projects or a single 6 MW project. Potomac Edison's proposal does not discuss the company's current DER management capabilities.

The $28 million budget cap is based on a single data point, which is the contract cost for PE's only third-party owned battery energy storage contract from the Commission's battery storage pilot program under PUA § 7-216,[16] which was solicited in 2020. The Potomac Edison pilot project upon which the proposed budget cap is based is 1.75 MW in size, with a contract payment of $550,00 per year.[17] Potomac Edison scaled this cost linearly to reach a value of $2.3 million per year and then applied a 20 percent escalation factor to this value "to account for cost increases and/or contingency," resulting in an annual projected cost for its proposed distribution-connected energy storage procurement mechanism of $2.76 million per year.[18] PE presumes the contract will be for 10 years, resulting in the proposed $28 million budget cap.[19] Potomac Edison is requesting approval of an annually reconcilable surcharge cost recovery mechanism to

[15] Potomac Edison Proposal at 2 (CN 9715 Feb. 21, 2025) ML 316132.
[16] *See* Petition for Participation in Energy Storage Pilot Program (CN 9619 Apr. 15, 2020) ML 229737.
[17] Case No. 9715, Office of People's Counsel Data Request 1-1. (February 26, 2025).
[18] *See id.*
[19] *Id*.

recover its costs. The company does not specify how it would allocate costs across classes.

## COMMENTS

### I. The Commission should require the electric companies to perform transparent, utility-specific, benefit-cost analyses for their proposed procurement mechanisms and implement other safeguards to ensure that procurements provide net benefits to utility customers.

#### A. The Commission should require the electric companies to perform utility-specific BCAs for their proposed procurement mechanisms using the Commission's unified benefit cost-analysis (“UBCA”) framework.

The Commission should not approve any of the utilities’ proposed procurement mechanisms until the utilities have conducted transparent benefit cost analysis (“BCA”) for those mechanisms. This analysis will provide the Commission and stakeholders with more data on the expected relative cost-effectiveness of the wide array of proposed mechanisms, helping the Commission determine which mechanisms to approve and the appropriate distribution of target allocation across the different mechanisms. The utilities should conduct separate BCAs for each type of procurement mechanism the Commission approves for purposes of compliance filings. To the extent that procurement mechanisms may result in cross-utility benefits and potential cross-utility subsidization of benefits (such as through reduced capacity prices), the utility BCAs should clearly identify and quantify such benefits to ensure that costs can be allocated in a manner commensurate with benefits.

### B. The Commission should require appropriate cost-efficiency mechanisms to ensure that procurement mechanisms result in net benefits for utility ratepayers to the maximum extent possible.

The MESP Workgroup's Phase 1 final report provided a non-consensus recommendation that the Commission apply a cost-efficiency standard, as opposed to a cost-effectiveness standard, to approve energy storage programs. The Commission effectively accepted the cost-efficiency standard in its RM 85 rulemaking process by defining the term "cost-effective" to mean "having projected benefits that are greater than projected costs while considering other factors as determined by the Commission,"[20]

Because the Commission's definition of cost-effectiveness allows for the approval of procurement mechanisms that do not have positive benefit-cost ratios, the Commission should ensure the application of strong cost-efficiency safeguards to all procurements. This is a necessary corollary to the use of a cost-efficiency standard for cost-effectiveness and consistent with the MESP Workgroup's Phase 1 final report. Among other things, that report states that "any attempt to bridge the 'money gap'… as part of the design of a procurement mechanism would need to be justified by sound reasoning that the potential value that may be delivered to ratepayers and/or the state … from the successful deployment of these resources may be equal to or greater than the cost of paying to bridge that 'money gap.'"[21] The workgroup also offered a near consensus

[20] COMAR 20.50.14.02.
[21] Case No. 9715, Phase 1 Final Report at 57 (Oct. 1, 2024) ML 312609.

recommendation to "apply cost-efficiency safeguards to ensure that prices are paid within reasonable bounds, as determined by industry cost data."[22]

One way for the Commission to protect utility customers from unreasonable and excessive procurement costs is to require utilities to provide bid data and evaluation methodologies and results from the procurement processes to the Commission under a confidentiality agreement, with Commission Staff and OPC afforded access to those materials. The PJM interconnection queue timeline is currently acting as a barrier to new market entrants for energy storage resources that must go through PJM's interconnection process. As a result, only energy storage resources that are already in PJM's interconnection queue are likely to be able to participate in any of the currently proposed procurement programs, given the multi-year wait times.[23]

According to MAREC Action, there are currently 17 active storage projects located in Maryland in the PJM queue with a total MW capacity of 1,627 MW.[24] These projects may be the only resources that are able to participate in the proposed transmission system-connected procurements, which will likely target procuring between 600 and 750 MW of transmission-connected storage (depending on the Commission's

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[22] *Id.* at 59.
[23] FERC recently approved amendments to the PJM tariff enhancing Surplus Interconnection Service (SIS). *See Order Accepting Tariff Revisions* 190 FERC ¶ 61,084 (Feb. 11, 2025). The new SIS provisions could allow new battery project interconnections outside of the queue by enabling interconnection of new battery projects if they share capacity interconnection rights with a generator which already has transmission service. While SIS might allow non-queue projects to participate, the recentness of the tariff provisions and lack of examples of new projects successfully utilizing SIS should encourage the Commission to take a cautious approach and assume that interconnection queue barriers might still impact the competitiveness of the procurement process.
[24] Comments of MAREC Action, *Maryland Energy Storage Program* at 3 (CN 9715 Nov. 5, 2024).

decision in this proceeding regarding the allocation of transmission and distribution connected storage). There is no publicly available data on the ownership of this set of projects or regarding whether multiple projects are owned by either a single developer, or companies that are subsidiaries of the same holding company.

Given the considerable barriers to new market entrants, there is a substantial risk of anti-competitive behavior in the RFP processes. This risk has the potential to lead to inflated bids, unnecessarily increasing costs to consumers. Under the Exelon utilities' proposed regulatory asset cost recovery mechanism for third-party owned storage contracts, the utilities would earn a return on the annual contract costs and would therefore earn more revenue from higher cost contracts. Therefore, the utilities may not be properly incentivized to ensure that the RFP process is competitive and that selected bids are cost-efficient and in line with current industry cost data. To safeguard against this risk, the Commission should require the utilities to share their bid data and evaluation methodologies and results from the procurement processes. The utilities should also be required to provide documentation of their review and comparison to industry cost data, at the time of the procurement.

Furthermore, if the Commission decides to approve full-tolling agreements, the Commission should cap the utility-paid annual contract costs at the expected PJM capacity market price cap, as measured in dollars per MW-day of capacity.[25] If the annual

[25] PJM's capacity market price cap will either be determined by the applicable FERC tariff, or in the near term, through a settlement agreement between PJM and Pennsylvania's governor's office that is currently under consideration by FERC. The utilities should consider the most recent available data regarding the expected capacity market price cap at the time of the bid evaluations.

contract costs are greater than the PJM's capacity market price cap, then the utilities would be able to purchase firm capacity through the wholesale market at a lower cost with the result that it would not be cost-effective or cost efficient for them to procure the storage.

To further safeguard against the potential negative impacts from programs that might not be cost-effective, the utilities should perform distributional equity analysis of bill impacts for each procurement in the individual utility territories. The Exelon utilities offered to conduct this analysis to assess affordability~~,~~ and equity impacts for different customer segments, ~~,~~ if deemed necessary.[26] Understanding the bill impacts on disadvantaged communities will be especially critical if BCAs show that procurement mechanisms are not likely to be cost-effective. In such cases, the Commission could decide that procurement mechanism costs should be recovered under limited-income mechanisms designed under PUA § 4-309 to ensure that the burden of net costs is not being inequitably distributed across different customer groups. The Commission should also consider setting a threshold bill impact above which programs will not be approved, similar to the bill impact cost control mechanism in Maryland's offshore wind procurement program.[27]

[26] Joint Exelon Proposal at 17-18 (CN 9715 Feb. 21, 2025) ML 316129.
[27] *See* PUA § 7-704.1(f)(1)(iii). In the context of this statute regarding offshore wind pricing, the ratepayer impact threshold is a calculation of the blended, net rate impact to ensure that any pricing schedule for offshore wind renewable energy credits ("ORECs") does not exceed a certain percentage or dollar amount of monthly residential electric bills based off a determined usage.

Finally, there should be regular retrospective analyses of the cost-effectiveness of these programs to understand the extent to which benefits are actually realized, and whether modifications are necessary for future procurements.

## II. The Commission should not approve the Exelon utilities' and Potomac Edison's proposed FTM distribution-connected procurement mechanism until the utilities show that they have the technical capability to cost-effectively realize the benefits of distribution-connected storage.

Distribution-connected energy storage resources, whether utility-owned or third-party-owned, have the potential to not only reduce system peaks, but also to help provide various distribution-level benefits, including local peak demand reduction and distribution infrastructure upgrade deferral at the substation, transformer, and feeder levels. However, these benefits can be fully realized only if a utility has adequate visibility into and appropriate control of its distribution assets and—in cases where storage assets will be aggregated by third parties—if the utility has developed appropriate systems to enable such aggregation. To date, neither the Exelon utilities nor Potomac Edison have demonstrated these capabilities.

For battery storage to defer traditional infrastructure upgrades and be incorporated into the utility's distribution system planning and operations, the utility must be able not only to identify specific locations at risk of overload and the timing of local peaks at those locations, but also to ensure that distribution-connected storage assets are dispatched at those specific locations and times. Without a DERMS with suitable capabilities and utility experience utilizing those capabilities, battery dispatch will most likely not be precise enough to reliably address local peaks and enable infrastructure upgrades to be deferred. The Exelon utilities have not demonstrated that they have the DER management and control capabilities to ensure that the distribution benefits of energy storage can be realized. The Exelon utilities' experience with distribution-connected storage through the Maryland Energy Storage Pilot Program has focused to-date on peak shaving and operation in PJM markets, not distribution benefits.[28]

For example, BGE's 2025 project list from its multi-year rate plan docket includes a DERMS storage optimization and DERMS optimization project, with a combined cost of around $7.3 million.[29] According to BGE's problem statement for the DERMS implementation project, "the current solution for monitoring and controlling BGE's DER assets involves a custom real time calculation in the Distribution SCADA system which requires manual maintenance and is not scalable to meet the DER growth expected in the near future."[30] This suggests that while BGE is starting to develop its DERMS capabilities, its current solution may not be able to fully realize the benefits of a distribution-connected procurement of this scale. The other utilities have not sufficiently demonstrated their DERMS capabilities either or shown that their planned capabilities are consistent with Maryland's state policies and will be deployed and implemented cost-effectively. To the extent that distribution-connected energy storage assets are used to address system peak demand and reduce the utilities' capacity costs, rather than address distribution infrastructure issues, DERMS may be less important. Distribution-connected

[28] Joint Exelon Proposal at 5 (CN 9715 Feb. 21, 2025) ML 316129.
[29] 2025 Capital and O&M Project Lists and Operation Pipeline Project Lists (CN 9692 Jan. 31, 2025) ML 315328.
[30] *Id.* at 23.

batteries may be able to be deployed more quickly than transmission connected batteries, because they often do not need to go through the slow PJM interconnection process. Given that PJM capacity market prices are currently extremely high, the potential near-term capacity cost savings are high. These timing and near-term cost savings considerations may potentially justify the deployment of distribution-connected storage even without fully realizing distribution benefits. However, this will depend on the project specific costs, benefits and relative speed of deployment.

Consistent with the discussion above, the Commission should direct the Exelon utilities to provide a detailed plan for the development and implementation of the DERMS discussed in their proposal, and direct Potomac Edison to detail its plans for effectively and cost-effectively managing or facilitating the third-party management of distribution-connected storage assets on its system. The utilities' plan should, at a minimum, explain the utilities' current distributed energy resource management and control capabilities and the specific uses that the companies intend for their DERMS systems. The utilities should also provide timelines for bringing their DERMS systems into operation.

## III. The Commission should deny the Exelon utilities' proposal to -own transmission-connected energy storage assets, as this would undermine the development of a competitive marketplace for third-party owned transmission-connected energy storage in Maryland.

The Commission should not approve the Exelon utilities' proposal to own transmission-connected storage for at least three reasons. First, the Exelon utilities have not justified why utility ownership of transmission-connected storage is necessary for addressing bulk-level resource adequacy challenges and wholesale services within the state. Second, utility ownership of transmission-connected energy storage may inhibit the growth of a competitive marketplace for economic, third-party-owned storage deployment. Third, it is likely that utility-owned transmission-connected storage will have higher costs than third-party owned transmission-connected storage, as utilities would not have to compete for procurement via a competitive RFP process.

Moreover, if the Commission directs the Exelon utilities and Potomac Edison to procure third-party-owned storage assets through tolling agreements—whether they are partial-tolling agreements or full-tolling agreements—the procurements can be designed, and the contracts written, to minimize the risk of project cost overruns and other project risks. By contrast, if utilities purchase costly transmission-connected storage assets, utility customers will invariably bear those risks. On the other hand, the Exelon utilities have not shown that utility ownership of transmission-connected storage assets will provide any unique benefits to utility customers. For these reasons, the Commission should reject the Exelon utilities' proposal to acquire and rate-base transmission-connected energy storage assets.

## IV. Procurements of third-party owned transmission-connected storage should include strong safeguards that ensure net benefits for customers to the maximum extent possible and fairly allocate risks among ratepayers, ESD owners, and electric companies.

For the procurement of third-party owned transmission-connected storage, the Exelon utilities propose the use of full-tolling agreements with 15-year terms and the deferral of annual agreement costs to regulatory assets.[31] Under the full-tolling agreements developers would, in exchange for contracted payments over the life of the agreement, be required to construct ESDs, complete PJM interconnection requirements, and enable PJM market participation. When procured ESDs enter commercial operation, the utilities would fully control the ESDs and be responsible for participating in PJM markets and providing grid services.[32] The regulatory assets would be amortized over five years and included in rate base until  they are fully recovered.[33] The Exelon utilities' proposal also includes a profit-sharing mechanism whereby the utilities would keep 30 percent of any wholesale revenues that exceed annual contract costs, an arrangement the utilities state is necessary "to incentivize strong PJM market participation."[34]

### A. **The use of partial-tolling agreements instead of full-tolling agreements would help mitigate wholesale market risk to ratepayers.**

To reduce the annual fixed costs and shift risk away from ratepayers, the Exelon utilities should consider soliciting storage assets via partial-tolling agreements rather than full-tolling agreements. Under a partial-tolling agreement, utilities could contract for capacity and the associated capacity market revenues. Project developers would own revenues from the energy and ancillary services markets and would be responsible for participating in those markets. Because project developers keep the energy and ancillary revenues, the fixed contract costs of a partial-tolling agreement should be lower than the fixed contract costs of a full-tolling agreement. Depending on the project-specific bids

[31] *See* Joint Exelon Proposal at 14 (CN 9715 Feb. 21, 2025) ML 316129.
[32] *Id.*
[33] *See id* at 15.
[34] *See id.*

and projected wholesale revenues, partial-tolling agreements may reduce costs for ratepayers and should reduce ratepayer risk by minimizing ratepayer exposure to the wholesale markets, while still incentivizing battery deployment in Maryland. The Exelon utilities should conduct a cost-effectiveness analysis comparing full-tolling agreements to partial-tolling agreements to provide the Commission with information needed to understand the differences in cost and benefits between these contract structures.

For instance, California has procured energy storage via both "Resource Adequacy" and "All Attributes" contracts. California's Resource Adequacy contracts (which are analogous to partial-tolling agreements that transfer capacity market revenues in the PJM context) pay storage resources to be available during peak demand and grid stress periods, effectively acting as a capacity payment. In contrast, the All Attributes contracts, which are effectively full-tolling agreements, transfer all operational control to the utilities, along with all wholesale revenues from energy and ancillary markets. The "Resource Adequacy Only" storage contracts from 2020-2021 have had average prices around $6-8/kW-month, whereas the "All Attributes" storage contracts over the same time period have average costs of around $7-22/kW-month.[35] Although the "All Attributes" contract is more expensive, it also includes revenues from all market streams. Given that wholesale market conditions can vary, the ultimate ratepayer impacts will

[35] Energy Storage Procurement Study, Prepared by Lumen Energy Strategy for the California Public Utilities Commission at 23 (May 31, 2023) *available at* https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/energy-storage/2023-05-31_lumen_energy-storage-procurement-study-report.pdf.

depend on whether the additional wholesale market revenues are sufficient to offset the higher fixed costs, demonstrating the risk that full-tolling agreements pose.

While the cost-effectiveness will ultimately depend on project specific costs and benefits, a partial-tolling agreement is expected to reduce ratepayer risk, relative to a full-tolling agreement. OPC recommends that the Commission require the Exelon utilities to analyze the costs, benefits and ratepayer risks and impacts associated with these different contracting mechanisms. If the Commission authorizes the use of full-tolling agreements to procure transmission-connected storage, it should deny the Exelon utilities' proposed profit-sharing mechanism or require the sharing of both profits and losses.

The distribution of risks and benefits regarding net wholesale market revenues under the Exelon utilities' proposal is asymmetrical and places all risk on ratepayers. Under the proposed framework, if wholesale market revenues exceed the annual contract costs, the utilities will be able to keep 30 percent of the annual wholesale revenues above the annual contract cost. However, wholesale market revenues are volatile, and high market revenues are not guaranteed. If the wholesale market revenues are less than the annual levelized contract costs, the net costs will be recovered from ratepayers. If there are years in which the wholesale market revenues exceed annual contract costs the Exelon utilities will earn a profit. However, if there are years when the wholesale market revenue is reduced, ratepayers will be on the hook for the remainder of the contract costs, while the utilities will still recover the full contract costs, plus their return, through the regulatory asset mechanism. This proposed risk allocation leaves ratepayers vulnerable to volatile wholesale market conditions, while the project developers and the utilities are fully insulated from any risks.

Furthermore, the Exelon utilities' proposed framework includes a double incentive, since the Exelon utilities can earn a return on regulatory asset costs and earn revenue through the proposed wholesale profit share mechanism.

### C. The Commission should defer approving Potomac Edison's request to expense costs annually until a final estimate of project costs is approved.

Generally, Potomac Edison's proposal to recover contract through a surcharge expensed on an annual basis represents an approach properly protective of ratepayers. That said, without yet having a final estimate of project costs it is impossible to determine if expensing all costs in the year they are incurred could impose a burdensome rate shock on customers. As such, the Commission should defer approving Potomac Edison's cost recovery proposal until a final project cost estimate is filed, at which point the Commission should consider amortizing the costs of the project over a number of years, with Potomac Edison eligible to receive carrying costs at the average cost of debt.

### D. The Commission should deny the Exelon utilities' request to defer the costs of transmission-connected storage procurement agreements to regulatory assets that are included in rate base and recovered at the utilities' full authorized rate of return.

The Commission should deny the Exelon utilities' proposal to recover contract costs (which are paid to the battery project developer) through a regulatory asset that is moved into rate base and amortized over 5 years. From an accounting perspective, this would treat these contract costs as a capital investment, with the Exelon utilities earning a rate of return on the contract based on their weighted average cost of capital ("WACC").

Given that contract payments and other costs associated with tolling agreements are clearly not capital expenditures, it is not in the ratepayer interest for the Exelon utilities to receive a return on these expenditures at their WACC. Even if the utilities do not seek to earn carrying costs on their regulatory assets (or if the Commission does not permit them to do so), ratepayers would be burdened with unnecessarily high costs due to the utilities' earning their authorized rate of return on their regulatory assets.

Whether the Commission authorizes the use of partial tolling agreements or full tolling agreements for the procurement of transmission-connected resources, the utility costs associated with those agreements will be O&M costs that should be expensed in the year they are incurred, absent a showing that expensing would harm ratepayers or otherwise be contrary to the public interest. Such a framework would align with the Commission's orders in the Maryland Energy Storage Pilot Program.[36] In Order No. 89664, the Commission approved Exelon Companies' proposals for the Energy Storage Pilot Program finding that

> "[T]he 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."[37]

[36] The Exelon-SEIA Proposal suggests that Commission orders in the Energy Storage Pilot Program allowed for recovery of the costs of third-party-owned battery storage through a regulatory asset. Exelon-SEIA Proposal at 4 (CN 9715 Feb. 21, 2025) ML 316131. As discussed below, OPC reads the orders in the Pilot Program to not allow third-party owned projects to be recovered in a regulatory asset.
[37] Case No. 9619, Order No. 89664, Order on Energy Storage Pilot Proposals at 25 (Nov. 6, 2020).

For utility-owned projects, the Commission allowed the Exelon companies "to track capital and O&M spending within a regulatory asset, with investments and expenses tracked separately for each project," presumably to allow O&M and capital costs to be recovered under distinct frameworks. The Commission placed the same restrictions on recovery of O&M costs for third-party owned projects when approving Potomac Edison's pilot projects.[38]

While the Commission's decisions in the Maryland Energy Storage Pilot Program docket left open the opportunity for utility-owned storage ~~may allow for the~~ to defer~~ral of~~ O&M costs for utility-owned projects to regulatory assets, its decision in that docket was premised on a different set of considerations from those that apply to the pending procurement proposals. Pilot programs are, by definition, extraordinary and non-recurring, making additional incentives for program implementation potentially reasonable. By contrast, the procurements in this docket are part of utilities' broader service obligations and so should reflect standard cost recovery frameworks. If the Commission does decide to allow track capital and O&M spending within a regulatory asset, the Commission should require that capital and O&M expenses are tracked separately for each project, as it required in the Energy Storage Pilot Program, and should only allow O&M costs to be expensed or, in the alternative, should only allow utilities to earn a return for O&M expenses at the average cost of debt. Such an approach would also

[38] Case No. 9619, Order No. 89805, Order on Energy Storage Pilot Proposals of Potomac Edison at 17 & n.86 (Apr. 21, 2021) (approving the Potomac Edison proposal subject to "conditions for project approval" including the provisions in Order 89664 regarding "recovery of O&M costs for third-party owned projects").

align with broader Commission policies recognizing that recovering program costs through regulatory assets can be harmful to ratepayers. For example, in Order No. 90306, the Commission recognized that the continued regulatory asset treatment of EmPOWER costs is not in the public interest and found it necessary to transition to full annual expensing of EmPOWER costs to avoid continuing to increase the unamortized balance.[39]

## V. Potomac Edison's distribution-connected program budget should be based on the results of a competitive RFP process, and as with the Exelon utilities, Potomac Edison should demonstrate their ability to realize distribution system benefits prior to program approval.

Potomac Edison's proposed budget cap is based on a single data point from a 2020 solicitation process and is escalated by an arbitrary 20 percent to account for cost increases and contingency spending. Since 2020, battery energy storage technology costs have declined.[40] Furthermore, battery storage costs vary on a $/MWh basis according to system size and duration, due to economies of scale. The contract cost for a single 1.75 MW energy storage contract solicited in 2020 is not an appropriate benchmark to use to set a budget cap for the proposed 6 MW program, which will consist of a yet-to-be-defined distribution of storage system sizes.

Potomac Edison should use the results of its competitive RFP process to inform its program budget. The results of the competitive RFP process should be reported to the

[39] Case No. 9648, Order No. 90306, Order on Cost Recovery for the 2024-2026 EmPOWER Maryland Program Cycle at P 24-25 (Aug. 16, 2022).
[40] Canary Media, *Chart: Lithium-ion battery prices fall yet again, available at*https://www.canarymedia.com/articles/batteries/chart-lithium-ion-battery-prices-fall-yet-again

Commission, and an updated budget cap, that relies on the competitive RFP results, should be proposed at that time.

Similar to the Exelon utilities, Potomac Edison should provide more detail on a roadmap to implement a distributed energy resource management system and provide more detail on its current distributed energy resource management and control capabilities, prior to distribution-storage program approval.

## VI. Potomac Edison should propose a transmission-connected, third-party owned procurement program to ensure that benefits and risks are distributed across all investor-owned utility ratepayers in Maryland.

Potomac Edison has stated that it does not propose a direct role in incentivizing or owning transmission-level energy storage projects at this time but will continue to collaborate with the MESP Workgroup on this topic.[41] By not implementing a similar transmission level program as the Exelon utilities, Potomac Edison will shift a greater quantity of the state's storage target to the Exelon utilities than they might otherwise procure. If these transmission-level energy storage procurement programs turn out to be cost-effective, and provide net benefits to ratepayers, Potomac Edison's ratepayers will not have the opportunity to see the same set of benefits that Exelon utilities' ratepayers will see. If these programs turn out to not be cost-effective, the cost burden of achieving Maryland's energy storage goals will be concentrated among Exelon utilities' ratepayers, as opposed to being more evenly distributed among all investor-owned utility ratepayers in the state. To maximize the overall benefits of batteries to the state of Maryland, all

[41] Case No. 9715, Staff  Data Request 1-1. (Mar. 12, 2025).

investor-owned utilities should be procuring transmission-level batteries. The OPC recommends that the Commission require Potomac Edison to propose a transmission-level battery procurement program, in line with the Exelon utility program and the recommendations outlined above.

## RECOMMENDATIONS

For the reasons discussed OPC makes the following recommendations:

1. The Commission should deny both the Exelon utilities' proposal to procure utility-owned transmission-connected energy storage devices ("ESD") and the utilities' proposal to procure utility-owned distribution-connected ESDs located on customer properties. On one hand, the Exelon utilities have not demonstrated that utility ownership of either type of storage asset would provide unique benefits to customers. On the other hand, allowing utility ownership of such assets would impede the development of competitive markets for storage assets and services and could expose customers to greater risks.

2. Given the paucity of details in the proposals of both the Exelon utilities and Potomac Edison to procure third-party-owned transmission- and distribution-connected ESDs, the Commission should defer approval of those proposals pending the utilities' submission of further compliance filings that include benefit-cost analyses, bill impact analyses, and other information the Commission needs to assess the affordability and equity impacts of the proposed procurement

mechanisms, with the goal of ensuring that procurements will result in net benefits to utility customers.

3. The Commission should require both the Exelon utilities and Potomac Edison to include in their compliance filings detailed budgets based on current and adequate information. The Exelon utilities' procurement proposals include no budgets, while Potomac Edison's proposed $28 million budget cap is based on limited and outdated information regarding a single pilot project.

4. The Commission should direct the Exelon utilities to provide a detailed plan for the development and implementation of the distributed energy resource management Systems ("DERMS") discussed in their proposal. The plan should, at a minimum, explain the Exelon utilities' current distributed energy resource ("DER") management and control capabilities and the specific uses that the companies intend for their DERMS systems. The plans should also provide a timeline for bringing their DERMS systems into operation.

5. With respect to the Exelon utilities' proposal to procure third-party owned transmission-connected energy storage through 15-year, full-tolling procurements in which the utilities would make fixed payments to developers to build and interconnect projects, then be responsible for bidding the projects into PJM's wholesale markets and securing PJM revenues, the Commission should:

c) Direct the utilities to provide benefit-cost analysis for procurement through partial-tolling agreements as a point of comparison to the utilities' full-tolling agreement BCA.

d) If the Commission should authorize the use of full-tolling agreements, deny the utilities' proposal to retain 30 percent of annual wholesale revenues above levelized contract and implementation costs, or in the alternative require the utilities to bear some of the risk that contract and implementation costs will exceed wholesale revenues. Under the utility-proposed framework proposed in their filings, the risk of annual wholesale market revenues being lower than annualized contract costs would be borne entirely by ratepayers.

6. The Commission should require Potomac Edison to file a transmission-connected third-party owned procurement program that aligns with the recommendations above regarding the Exelon utilities' program.

7. The Commission should defer approval of cost recovery mechanisms for transmission-connected battery storage projects until after the Commission approves project costs. The Commission should generally require utilities to expense all operating and maintenance costs in the year they are incurred but should consider amortizing the costs of the initial years of the projects if expensing the costs entirely in the first year would impose unreasonable costs on utility customers.

a. Regarding the Exelon utilities' proposal, the Commission should either deny the use of regulatory assets to recover tolling agreement costs and instead require the utilities to expense those costs in the years they are incurred or—if the Commission authorizes the use of regulatory assets—determine that the return on assets used to recover tolling agreement costs shall not exceed the utilities' cost of debt. Because tolling agreement costs are not capital expenditures, they should not be recovered at the utilities' weighted average cost of capital (WACC). Either of these alternative cost recovery mechanisms will avoid the unjustified profits on non-capital expenditures and unnecessary customer bill impacts.

b. Regarding the Potomac Edison proposal, while expensing costs is generally protective of ratepayer interests, the Commission should defer approving expensing costs annually until a final estimate of project costs is approved. In the event expensing project costs would result in a shock to ratepayers, the Commission should amortize the costs over an appropriate time period and allow Potomac Edison to recover carrying costs at the average cost of debt.

OPC appreciates the opportunity to comment on the Exelon utilities' and Potomac Edison's proposed storage procurement mechanisms and looks forward to further engagement with the utilities, other stakeholders, and the Commission on these important matters.

Respectfully submitted,

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