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August 30, 2024

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W., Suite 800
Washington, DC 20005

Re: Formal Case No. 1176

Dear Ms. Westbrook-Sedgwick:

Enclosed please find Potomac Electric Power Company's Post Hearing Brief in the above-referenced proceeding.

If you need additional information or have any questions, please do not hesitate to contact me.

Sincerely,

/s/ *Kimberly A. Curry*

Kimberly A. Curry

Enclosures

cc: All parties of record

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF	)	
	)	
THE APPLICATION OF	)	**FORMAL CASE NO. 1176**
POTOMAC ELECTRIC POWER	)	
COMPANY FOR AUTHORITY TO	)	
IMPLEMENT A MULTIYEAR	)	
RATE PLAN FOR ELECTRIC	)	
DISTRIBUTION SERVICE IN THE	)	
DISTRICT OF COLUMBIA	)	

POST LEGISLATIVE STYLE HEARING BRIEF OF POTOMAC ELECTRIC POWER COMPANY

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August 30, 2024

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IN THE MATTER OF	)	
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IMPLEMENT A MULTIYEAR	)	
RATE PLAN FOR ELECTRIC	)	
DISTRIBUTION SERVICE IN THE	)	
DISTRICT OF COLUMBIA	)	

POST-LEGISLATIVE-STYLE HEARING BRIEF
OF
POTOMAC ELECTRIC POWER COMPANY

Pursuant to the directive of the Public Service Commission of the District of Columbia (the "Commission") in Order No. 22015,[1] Potomac Electric Power Company ("Pepco" or the "Company") hereby submits its Post-Legislative-Style Hearing Brief ("Brief").[2] The Brief addresses issues raised during the legislative-style hearing held on July 30, 2024 ("Hearing") and in the limited briefs filed by other parties in advance of the Hearing.[3]

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1 Formal Case No. ("FC") 1176, Order No. 22015 at ¶9. Full case citations are provided in the Table of Authorities to this Brief.

2 Although Order No. 22015 did not require it, for the Commission's convenience the Company has attached to this Brief, as Appendix A, the exhibits from Company Witness Leming's Rebuttal Testimony that shows the revenue impact of each of the Company's proposed cost-of-service adjustments in connection with the MYP and, as Appendix B, Proposed Findings of Fact and Conclusions of Law.

3 Additionally, because the Pre-Hearing Brief was limited to 30 pages, this Brief addresses issues that were not addressed in the Pre-Hearing Brief and provides more in-depth information and analysis on topics that were addressed at a higher level in the Pre-Hearing Brief.

I. SUMMARY

Pepco's proposed multi-year plan ("MYP"), the Climate Ready Pathway, is reasonable, in the public interest, supported by substantial evidence in the record, and should be approved by the Commission. Approval of the MYP as an alternative form of regulation ("AFOR") is justified and will provide important incremental benefits to customers, the District of Columbia, the Commission, the Company, and other stakeholders.

District customers will benefit from the investments and programs that the Company implements in this MYP. As discussed in detail in the record and herein, these investments will enable a pathway to a "Climate Ready Grid"[4] by, as examples, expanding capacity for distributed energy resources ("DER"), improving customer communication and control of energy usage, and improving cyber and physical security. Through the projects planned across the duration of this MYP, such as the continuation of the progress on Capital Grid and the long-term strategy to replace aging infrastructure under the Downtown Resupply project, the Company can continue to make the investments at the pace and level needed to provide safe, reliable, and resilient service by preventing degradation of aging infrastructure and mitigating environmental risks. A more reliable and resilient grid is also the platform for a climate ready grid. In addition, Pepco proposes in this MYP customer-benefiting investments to support climate goals, including integration between the community solar and billing platforms and expansion of the interconnection team to support the increasing demand for interconnections, and enhancements to the benchmarking energy reporting

[4] Climate Ready Grid is the Company's term for infrastructure and processes that advance system-readiness and support District customers through the energy transformation required by the District's climate policies. PEPCO (A): O'Donnell Direct at 13:20-21 – 14:1 ("Pepco's capital spending plan is designed to support a safe, reliable and resilient electric distribution system through investments that are foundational for a Climate Ready Grid."); PEPCO (H): Cantler Direct at 6:14-22.

services that facilitate the ability of building owners to track the energy efficiency of their buildings.[5] The investments in the Customer Flight Path projects will benefit customers by offering them enhanced digital self-service options and advance affordability by assisting customers in identifying available energy assistance programs and offerings. Customers have favorably recognized Pepco's past investment efforts, as evidenced by an overall customer satisfaction of 88% and 95% customer satisfaction with reliability at year end 2022.[6]

The District's most economically vulnerable customers will also benefit from the Climate Ready Pathway, through the Company's proposals to increase enrollment of eligible customers in the Residential Aid Discount ("RAD") program.[7] RAD provides a bill credit for nearly all of a customer's distribution portion of their bill[8] and the expansion of the program will extend this benefit to even more customers. In addition, the Company's proposed "automatic enrollment" feature for the Arrearage Management Program will enhance the customer experience for those most economically vulnerable. All residential and commercial customers benefit from the predictability that accompanies an MYP where rates are known for each year of the plan, allowing them to plan their budgets more effectively.

The benefits of the MYP extend further to provide economic benefits to the broader District, including expanding workforce development, and supporting supplier diversity. As a major economic and workforce driver in the region and the District, Pepco has awarded over 750 contracts to diverse Tier 1 suppliers totaling over $763 million within the scope of the DC MYP

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5 PEPCO (J): Hightower at 20:9-19.
6 PEPCO (J): Hightower at 8:10-13.
7 PEPCO (J): Hightower Direct at 29:6-7.
8 PEPCO (E): Bonikowski Direct at 32:6-9.

to date.[9] Moreover, the investments in the MYP will support 3,800 full time jobs, and $908 million in investment spend from vendors, employees, and services that are located in the District of Columbia.[10] This spending includes construction and other professional services, equipment, and other supplies from businesses located in the District.[11] The Company's internal processes require that prior to the approval of its grid modernization investments, a project team must detail how the project will create tangible benefits for customers, the local community, the environment, and meet the Company's business needs.[12] The Company's internal leadership assess detailed presentations of the quantitative, measurable customer benefits.[13] Pepco's continued performance in reducing the frequency and duration of outages and expanding DER capacity, while expanding economic development through its workforce development and expanding supplier diversity over the term of the first MYP, demonstrates the quantifiable and qualitative benefits to customers, the District and other stakeholders realized through Pepco's MYPs. Pepco customers in the District of Columbia experienced the lowest frequency of electric outages ever in 2022. The frequency of outages decreased from the previous low set in 2020 by more than 25%.[14] The Company plans to

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9 PEPCO (M): McClure Rebuttal at 5:15-19.

10 PEPCO (A)-1 at 2.

11 Id. at 5.

12 PEPCO (4H): Cantler Rebuttal at 34:15-18.

13 PEPCO (4H)-3 (Confidential) generally; *see e.g.*, PEPCO (4H)-3 at 274, 481 (13kV/Downtown Resupply, identifying customer benefits as reliability improvement, social benefits as increase in diverse supplier spend and local job opportunities, and environmental benefits as substation LEED certification, and increasing renewable energy integration); PEPCO (4H)-3 at 318 (4kV conversion project identifying customer benefits of conversion to 13 kV infrastructure, social benefits as increase in diverse supplier spend, and environmental benefits as delivery of more energy without increasing the environmental footprint); PEPCO (4H)-3 at 382 (NoMa feeders extension identifying customer benefits as reduced frequency and duration of outages, social benefits as providing greater reliability to customers historically impacted by outages, and environmental benefits of removing sludge and lead from the manhole system).

14 Since 2018, Pepco has improved its SAIFI by 43% and improved its SAIDI by 35%. PEPCO (H): Cantler Direct at 16:6-10.

maintain its first quartile status in the years ahead, while also planning a resilient system to withstand the effect of climate change.[15]

The Commission has already recognized the benefits of MYPs, specifically, to customers who will experience greater rate predictability, spread out over multiple years to achieve gradual rate increases, and to stakeholders due to reduced costs of litigation due to the filing of rate cases less frequently, and increased transparency into Company investments before those investments are made.[16] The MYP also supports the financial health of the utility, by reducing borrowing costs, with District customers experiencing those benefits directly through lower customer rates. These benefits remain intact and the Commission should not retreat from those previously established advantages of an MYP. As explained herein, Pepco has incorporated learnings from its first MYP, and any additional learnings from Pepco's prior MYP can be considered in parallel during the term of this MYP.

The Bill Stabilization Adjustment ("BSA") continues to serve as a strong incentive for the Company to not only support energy efficiency programs, but to also support other energy reducing measures, such as solar adoption, net energy metering, and distributed energy resources ("DER"), because it decouples electricity usage and Pepco's distribution revenue, thus protecting customers from fluctuations in their bills during increased energy usage due to extreme weather, which is an important consideration given the impacts from climate change, as well as shielding Pepco from the resulting financial harm that could result from customers using less energy.[17] Recovery of BSA deferral balances, which represents revenues the Company is unable to collect

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15 PEPCO (H): Cantler Direct at 51:2-5.
16 FC 1156, Order No. 20755 at ¶473.
17 PEPCO (3E): Bonikowski Rebuttal at 3:6-4:7.

due to the 10% monthly cap on recoveries, is necessary because those balances are the result of the Company administering the BSA in the manner approved by the Commission and prescribed in the Company's tariffs, and any disallowance would implicate the rules against retroactive ratemaking.

An increase in the Company's Return on Equity ("ROE") is warranted because the cost of capital has increased significantly since the Commission approved a 9.275% ROE for the Company in 2021 in its prior MYP in FC 1156. Pepco's proposed ROE of 10.5% is based on an examination of peer utilities and market conditions, and suggestions for a minimal increase or even a reduction of the ROE, based on an MYP or otherwise, that is not commensurate with capital markets must be rejected.

The Company's requested revenue requirement of $186.5 million across the three-year duration of the MYP, set forth below, is well supported by the record:[18]

Plan Year	12ME Dec 2024	12ME Dec 2025	12ME Dec 2026
Cumulative Revenue Requirement	$116.3M	$150.7	$186.5
Incremental Revenue Requirement	$116.3M	$34.5	$35.8

For the foregoing reasons, and because the Company's MYP is consistent with the framework the Commission adopted in FC 1156 Order No. 20273 (the "AFOR Order"), including

[18] If the Commission adopts the Company's proposed revenue requirement, the total 2026 bill for an average residential customer will have grown at a rate of only 2.43% since 2011, below the overall rate of inflation for that period of time.

satisfying the requirements specified in D.C. Code § 34-1504(d)(2),[19] the Commission should approve this MYP.

II. PROCEDURAL BACKGROUND

On April 13, 2023, Pepco filed its application (the "Application"), with supporting testimony and exhibits, requesting authority to implement the MYP pursuant to which the Company would establish just and reasonable rates and charges for electric distribution service in the District of Columbia through December 31, 2026. The MYP would allow Pepco to continue to provide affordable, safe, reliable, and resilient electric distribution service in the District consistent with the public interest and advance the District of Columbia's and the Commission's decarbonization and clean energy goals; implement enhancements to the RAD program and the AMP that provide important assistance to the District's most economically vulnerable residents; revise certain aspects of the Bill Stabilization Adjustment ("BSA"), informed by discussions from the BSA Technical Conference; and revise the terms and conditions related to electric distribution service in the District of Columbia, as well as other requested relief.[20]

On May 5, 2023, the Commission issued a Public Notice and Order No. 19956, in which it, *inter alia*, directed petitions for intervention to be filed by May 15, 2023. On May 31, 2023, by

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[19] D.C. Code § 34-1504(d)(2) states:

> The Commission may adopt an [AFOR] if the Commission finds that the [AFOR]:
> (A) Protects consumers;
> (B) Ensures the quality, availability, and reliability of regulated electric services; and
> (C) Is in the interest of the public, including shareholders of the electric company.

[20] Pepco filed direct testimony by Company Witnesses O'Donnell (PEPCO (A)), Leming (PEPCO (B)), Holden (PEPCO (C)), Gardiner (PEPCO (D)), Bonikowski (PEPCO (E)), McKenzie (PEPCO (F)), Barnett (PEPCO (G)), Cantler (PEPCO (H)), Vavala (PEPCO (I)), Bell-Izzard (PEPCO (J)), Efimova (PEPCO (K)) and Allis (PEPCO (L)). By letter dated January 9, 2024, Pepco informed the Commission that Company Witness Hightower would be adopting the testimony of Company Witness Bell-Izzard. Company Witness Hightower adopted this testimony in her Rebuttal Testimony filed on February 27, 2024. PEPCO (2J): Hightower Rebuttal at 1:19-20. By letter dated May 31, 2024, Pepco informed the Commission that Company Witness Vahos would be adopting the testimony of Company Witness Barnett.

Order No. 21630, the Commission granted intervenor status to the U.S. General Services Administration ("GSA"), the Apartment and Office Building Association of Metropolitan Washington ("AOBA), the District of Columbia Water and Sewer Authority, and the District of Columbia Government ("DCG").

By Order No. 21886,[21] the Commission adopted a procedural schedule for the proceeding, which was subsequently modified, most recently, in Order No. 22015. The Commission also directed Pepco to submit supplemental direct testimony: (i) addressing, in quantitative and qualitative terms, the benefits of, problems identified, and lessons learned from the MYP approved in FC 1156 (the "FC 1156 MYP");[22] (ii) addressing three items AOBA identified in comments submitted to the Commission;[23] and (iii) to support a traditional one-year rate case for the test period Calendar Year 2023.[24]

On August 31, 2023, Pepco filed supplemental direct testimony that addressed, in quantitative and qualitative terms, the benefits of, problems identified, and lessons learned from the FC 1156 MYP as well as the three items from AOBA's comments.[25] Subsequently, on October 16, 2023, Pepco filed further supplemental direct testimony that supported a traditional

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21 FC 1176 Order No. 21886 (Jul. 28, 2023).

22 Order No. 21886 at ¶29.

23 Order No. 21886 at ¶24. The three items that AOBA had raised in its comments were: (1) the relationship between the forecast of load and demands on which Pepco relies for capital planning and the Company's forecasted billing determinants; (according to AOBA, Pepco's projected capital additions for reliability appear inconsistent with the forecasts of declining overall kWh sales and kW demands it relies upon for rate design purposes); (2) the priorities Pepco assigns to capital projects and the likelihood such projects will be completed within each MYP year; and (3) the manner in which Pepco expects to adjust its planned capital expenditures in the event of project delays and/or cancellations and the adjustments the Company intends to make in the context of significant over- or underspending for specific planned projects. *Id*. at ¶6.

24 Order No. 21886 at ¶30.

25 On August 31, 2023, Pepco filed supplemental direct testimony by Company Witnesses O'Donnell (PEPCO (2A)) and Cantler (PEPCO (2H)).

one-year rate case for the test period Calendar Year 2023 (the "Traditional Test Year Compliance Filing" or "TTYCF").[26]

Direct testimony was filed on January 12, 2024 by OPC,[27] AOBA[28] and DCG.[29] Rebuttal testimony was filed by Pepco[30] and GSA[31] on February 27, 2024. AOBA[32] filed surrebuttal testimony on April 15, 2024, while OPC,[33] and DCG[34] filed surrebuttal testimony on April 22, 2024.

On March 12, 2024, OPC, DCG, and AOBA filed a Motion to Dismiss or, In the Alternative, Motion for Summary Disposition, which Pepco opposed in a response filed on March 22, 2024. On June 10, 2024, OPC and AOBA filed a Motion to Dismiss or, In the Alternative, Motion for Summary Disposition, which the Company opposed in a response filed on June 17, 2024. Finally, on June 24, 2024, OPC filed a Motion to Suspend the Procedural Schedule and a Request for Clarification to which Pepco filed a response in opposition on June 26, 2024. With Order No. 22013, the Commission denied the motions.[35]

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26 On October 16, 2023, Pepco filed supplemental direct testimony by Company Witnesses O'Donnell (PEPCO (3A)), Leming (PEPCO (2B)), Holden (PEPCO (2C)), Bonikowski (PEPCO (2E)), McKenzie (PEPCO (2F)), Vahos (PEPCO (2G)) and Cantler (PEPCO (3H)).

27 OPC submitted direct testimony from 5 witnesses: Dismukes (OPC (A)), Gorman (OPC (B)), Walters (OPC (C)), Andrews (OPC (D)) and Mara (OPC (E)).

28 AOBA submitted direct testimony from 2 witnesses: B. Oliver (AOBA (A)) and T. Oliver (AOBA (B)).

29 DCG had only 1 witness who filed direct testimony: Lane (DCG (A)).

30 On February 27, 2024, Pepco filed rebuttal testimony by Company Witnesses O'Donnell (PEPCO (4A)), Leming (PEPCO (3B)), Holden (PEPCO (3C)), Gardiner (PEPCO (2D)), Bonikowski (PEPCO (3E)), McKenzie (PEPCO (3F)), Vahos (PEPCO (3G)), Cantler (PEPCO (4H)), Hightower (PEPCO (2J)), Efimova (PEPCO (2K)), Allis (PEPCO (2L)), McClure (PEPCO (M)) and Tuladhar (PEPCO (N)).

31 GSA had only one witness who filed rebuttal testimony: Goins (GSA (A)).

32 AOBA Witness B. Oliver was the only AOBA witness to file surrebuttal testimony (AOBA (2A)).

33 OPC submitted surrebuttal testimony from 5 witnesses: Dismukes (OPC (2A)), Gorman (OPC (2B)), Walters (OPC (2C)), Andrews (OPC (2D)) and Mara (OPC (2E)).

34 DCG submitted surrebuttal testimony from Lane (DCG (2A)).

35 Order No. 22013 at ¶¶33-35. The Commission did direct Pepco to supplement its rate of return filings in FC 1156 for the 12 months ending December 31, 2023 and March 31, 2024 and provided the parties the opportunity to conduct discovery with respect thereto. *Id*. at 29.

On June 13, 2024, the Commission issued a notice announcing that it would convene a legislative-style hearing on July 30, 2024, to allow parties to present oral arguments regarding the issues they believed were fundamental to the Commission's decisions in this proceeding. The Commission also directed parties presenting oral argument at the hearing to file a limited brief regarding these issues.[36] Pursuant to Order No. 22013, the Commission also allowed parties to submit post-legislative-style hearing briefs.[37]

The Commission also held community hearings on March 27, 2024, April 2, 2024, and April 3, 2024.

As discussed herein and in the Pre-Hearing Brief filed on July 24, 2024 (the "Pre-Hearing Brief"), the record in this proceeding fully supports the adoption of the MYP.

III. DISCUSSION

A. The Commission Should Adopt Pepco's Proposed MYP.

Pepco has presented through extensive testimony a *prima facie* case supporting the adoption of its proposed MYP. The proposed MYP conforms with the framework principles and policies the Commission enunciated in the AFOR Order.[38] The proposed MYP also builds upon and incorporates enhancements based on the experience gained from operating under the FC 1156 MYP.

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[36] Limited briefs were filed by Pepco, OPC, AOBA and DCG.

[37] Post legislative-style hearing briefs were originally due on August 9, 2024; however, in response to a request by AOBA, the Commission in Order No. 22015 extended that date to August 30, 2024.

[38] FC 1156, Order No. 20273 ("AFOR Order").

1. The Company's current MYP produces benefits to customers, stakeholders, and the utility, and is consistent with the benefits envisioned by Commission orders.

In Order No. 20755, the Commission identified several benefits to an MYP, including: providing more predictable revenues for utilities and more predictable rates for consumers, spreading changes in rates over multiple years, and decreasing administrative burdens on regulators by staggering filings over several years.[39] The AFOR Order held that AFORs must consider, *inter alia*, the District's climate commitments and public policy goals, the quality, availability, and reliability of regulated utility services, the financial health of the utility, provide an appropriate level of transparency, advance the economy of the District, and provide benefits that are quantifiable to customers.[40] These outcomes are all present in the Company's MYP.

a. The MYP provides rate predictability for customers.

The Commission identified rate predictability and spreading rate increases over a period of years as a benefit of MYPs for customers.[41] As proposed in the MYP, customers know what their rates will be for each year of the MYP, which will enable them to effectively budget. Indeed, the Commission identified this as a particular benefit to commercial customers in the Company's first MYP, where it held that the Company's MYP "provides stability and predictability for small and large commercial customers because it spreads rates over a number of years thus helping the commercial customers plan their business operation costs."[42] Rate predictability for both residential and commercial customers are equally present in the instant case. This same level of predictability is not present in a historic test year case, because an historic test year proceeding is

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[39] FC 1156, Order No. 20755 at ¶92.
[40] AFOR Order at ¶6.
[41] FC 1156, Order No. 20755 at ¶ 92.
[42] FC 1156, Order No. 20755 at ¶146.

backward-looking, in which the Commission evaluates the Company's investments, spending, and results after the fact.[43] In contrast, under an MYP, the Commission can assess the Company's plans in advance, with annual touchpoints during the MYP period to observe how the Company is performing in relation to its filed plans.[44] Additionally, limited income customers experience additional rate predictability because they will not experience an increase as 1) RAD credits effectively cover the entire electric distribution portion of the bill and 2) AMP customers will experience further credits if they engage in timely bill payment.[45] The Company will also continue its customer outreach and education on available energy assistance, such as through Pepco's sponsorship of the annual Energy Assistance Summit.[46] In addition, the Climate Ready Pathway provides the opportunity to address the commercial classes' subsidization of the residential class, as discussed in Company Witness Bonikowski's Direct Testimony. The MYP achieves the rate predictability sought by the Commission.

b. The MYP is administratively efficient for the Commission and stakeholders.

The MYP process proposed by Pepco, both in FC 1156 and FC 1176, includes a full three-year plan, followed by subsequent three-year plans, so that rate proceedings are reasonably spaced and administrative efficiency is improved for the Commission and parties. Even accounting for reconciliation filings, the level of work for the Commission and other parties would be less than that required by annual, traditional rate cases.[47] If the Company is required to file traditional rate cases as opposed to MYPs, as Company Witness O'Donnell testified, the pace of investments

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43 PEPCO (2A): O'Donnell Supp. Direct at 7:3-5.
44 Id. at 7:5-8.
45 PEPCO (J): Hightower Direct at 32:22-33:6.
46 PEPCO (A): O'Donnell Direct at 20:9-21:3.
47 PEPCO (2A): O'Donnell Supp. Direct at 7:12-16.

being made would necessarily result in annual rate case filings, and annual traditional rate case filings would likely not allow Pepco to invest at the pace necessary to fully support the District's goals.[48] An important component of the MYP and the reconciliation is that, in addition to fostering efficiency, the asymmetric nature of the reconciliation mechanism mitigates the risk of utility over-earning and provides an incentive to manage costs, thereby avoiding shifting of risks to customers. Other important benefits of the FC 1156 MYP that are retained within the FC 1176 MYP proposal are the re-opener provision and the option for deferred accounting for one-time costs related to unusual events.[49] The MYP alleviates the administrative burden of back-to-back filings of traditional rate cases.[50]

c. The MYP advances District climate goals.

As Company Witnesses O'Donnell, Cantler and Hightower discuss, Pepco has a multi-pronged approach to implementing a Climate Ready Pathway to support the District's climate change goals. The projects in the MYP are designed to support the District's climate initiatives – these are fundamental building blocks necessary for the District to achieve its decarbonization goals and achieve a highly electrified and interactive system.[51] The Company has also filed separate plans in FC 1167 (the CSP Phase 1 Application addressing transportation and building electrification) and in FC 1160 (energy efficiency programs).

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48 PEPCO (2A): O'Donnell Supp. Direct at 9:5-9.
49 *Id*. at 10:3-9.
50 It is also administratively efficient to have a seamless transition between MYPs, Section III.A.5 describes the adverse impact customer rates of a "stay out," when a subsequent MYP does not become effective upon the expiration of the prior one.
51 PEPCO (A): O'Donnell Direct at 3:15-18.

The MYP includes a number of programs that are focused on improving systems and resources that support the customer experience in advancing DER proliferation. In fact, to date, Pepco has enabled a total 173 MW of DER in service in the District and an additional 4 MW is pending completion.[52] In order to continue incorporating additional DER onto the system, investments need to be made to be able to reliably support these resources. Proposed projects within this MYP, such as the conversion of feeders to higher operating voltages, which enables the implementation of distribution automation schemes and creates greater hosting capacity for DER, do just that.[53] The Company must proactively plan for the long lead time associated with these investments made in support of climate goals, because otherwise, the Company's distribution system will lag behind and be unable to meet the demands imposed by the energy transformation.

These programs are different from the customer-incentive and education programs proposed in FC 1167. For example, through RMA 16, Pepco included costs for programs that will enhance community solar and billing reporting services, integrate the community solar portal with the billing system, include subscriber organization fees in utility consolidated billing for community solar customers, and enhance the benchmarking energy reporting services provided to building owners in the District.[54] No party challenged RMA 16.[55] Similarly, RMA 19 addresses costs for Customer Operations to support the demand brought about by the increasing number of

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52 PEPCO (H): Cantler Direct at 16:16-17:1.

53 PEPCO (H): Cantler Direct at 37:10-12.

54 The programs included in RMA 16 were described in the Direct Testimony of Company Witness Hightower. PEPCO (J): Hightower Direct at 20:9-14. These programs, which are impactful to District's goals and policies on decarbonization and climate change, were added after the Long Range Plan ("LRP") used in preparing the MYP was finalized and thus their costs are recovered through RMA 16. *Id*. at 20:3-7. The costs are presented in the Direct Testimony of Company Witness Leming. PEPCO (B): Leming Direct at 59:20-60:2; PEPCO (B)-1, page 12 of 23.

55 *See* OPC (B)-2, AOBA (B)-3, Page 2 of 2.

installation requests.[56] No party challenged RMA 19.[57] Unlike FC 1167, Pepco is requesting that the Commission approve these programs and their funding as part of the MYP.

Finally, many of the MYP projects that support and advance the District's climate and clean energy goals also address distribution system reliability and resiliency. Indeed, some parties have complained that the Company does not have sufficient projects in its capital plan that are solely supporting specific District climate and clean energy goals. However, as Company Witness O'Donnell indicated in her Direct Testimony, the MYP funds projects that maintain reliability and resilience and such expenditures are foundational to enabling the electrification that is critical to advancing the District's climate and clean energy goals. Specifically, she explained:

> The distribution system needs to operate efficiently and effectively, especially with the growth in electrification that will be required to advance the District's decarbonization and clean energy goals. As customers increase their use of electricity at homes and businesses across the District, it will be even more vital that the grid function smoothly and provide consistent, reliable service. The investments in this MYP are fundamental to preparing the grid for customer adoption of electrification in the near-term and as conceived in District policy.[58]

She also emphasized that:

> Reliability is foundational to meet the everyday needs of Pepco's customers and is a core component of a Climate Ready Grid. Pepco customers, District leaders and the broader business community expect Pepco's electric distribution system to be reliable and to be able to withstand the impact of storms that are projected to increase in volume and intensity as a result of climate change. Therefore, the

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[56] PEPCO (J): Hightower Direct at 23:9-24:4. These programs, which are impactful to District's goals and policies on decarbonization and climate change, were added after the LRP used in preparing the MYP was finalized and thus their costs are recovered through RMA 19. *Id*. at 20:3-7. The costs of the expansion were presented in the Direct Testimony of Company Witness Leming. PEPCO (B): Leming Direct at 64:10-13; PEPCO (B)-1 at page 15 of 23.

[57] *See* OPC (B)-2, AOBA (B)-3, Page 2 of 2.

[58] PEPCO (A): O'Donnell Direct at 10:14-22.

Company must continue to make investments that maintain and harden its distribution system.[59]

Pepco's approach is reasonable and should be approved. It is also consistent with the framework principles adopted in the AFOR Order, which provide that:

- The AFOR advances . . . the preservation of environmental quality, including effects on global climate change and the District's public climate commitments;
- The AFOR's ratemaking mechanisms advance or otherwise align with the District's public policy goals.[60]

As discussed further in Section C, the capital investments included in the Company's Construction Report are reasonable and costs of the projects that are projected to be completed during the 3-year term of the MYP and benefitting customers are appropriately included in the MYP's rates.

The Company's investments in reliability and resilience are not "business as usual." Reliability is the bedrock of a Climate Ready Grid.[61] These are foundational requirements that are critical to the District achieving its decarbonization and electrification goals. As Company Witness O'Donnell explained "[a] more interactive grid is necessary to accommodate increasing deployment of distributed energy resources and manage increased electrification load." The capital investments Pepco is making "create a platform to support the proliferation of beneficial electrification measures in the District's transportation, buildings, and commercial sectors."[62] The distribution system needs to operate efficiently and effectively because, "as customers increase

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[59] PEPCO (A): O'Donnell Direct at 12:22-13:4. *See also id*. at 15:9-15 ("With the continued prevalence of working from home and increasing reliance on electricity in sectors such as transportation, customers will continue to expect a higher level of reliability and resiliency in their electric service. These expectations for reliability and resilience are likely to grow, as the District has established a decarbonization pathway with electrification as an approach.")

[60] AFOR Order at ii.

[61] PEPCO (A): O'Donnell Direct at 13:10-13.

[62] PEPCO (A): O'Donnell Direct at 5:14-19.

their use of electricity at homes and businesses across the District, it will be even more vital that the grid function smoothly and provide consistent, reliable service."[63]

Company Witness Allis explained some of the various ways in which the District's transition to a decarbonized energy system will impact the distribution system:

> First, transmission and distribution assets will need to be upgraded or replaced to incorporate intermittent and distributed generating sources as well as other distributed energy resources. Second, electrification of building heating, transportation and other energy uses will result in both load growth and a changing load profile which will, in turn, require upgrades and replacements for capacity reasons as well as increased wear and tear on equipment. Third, new technologies will be added to the grid, which typically have shorter service lives (particularly for digital equipment that replaces analog equipment). Fourth, as our reliance on the grid has increased and as the operating environment has become harsher (such as with more frequent and more severe storms), investments in resilience and reliability need to increase, resulting in increased replacements of assets. Electrification will increase this trend due to both increased load and an even higher reliance on the electric grid. Finally, a harsher climate (such as from more frequent storms and hotter summers) will increase wear and tear on assets as well as retirements from damage due to storms or other natural forces.[64]

As Company Witness Cantler explained, the system must be regularly modernized, maintained, hardened and, as needed, expanded, so that whatever choices the District and customers make, Pepco has provided a foundation on which the climate goals can be supported and advanced.[65] The MYP will facilitate the timely implementation of strategic utility investments

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63 PEPCO (A): O'Donnell Direct at 10:17-20.

64 PEPCO (2L): Allis Rebuttal at 9:3-16.

65 *See* PEPCO (4H): Cantler Rebuttal at 8:11-16 ("Continued investments in reliability and resiliency are paramount to establishing a pathway to a Climate Ready Grid because they enable the Company to proactively maintain and enhance the system to guard against negative customer impact associated with the potential of equipment failure due to age, obsolescence, etc. while also maintaining a system that can operate through variable weather and uncontrollable events from year to year. It is critical that the Company continues to invest in these programs and projects to address those issues throughout this MYP by replacing aging equipment and repairing the damage caused by storms and extreme heat to its system").

and the timely recovery of these investments will allow the Company to invest at the level and pace required to support and advance the District's climate and clean energy goals.[66]

d. The MYP supports a financially sound utility

The Commission may adopt an AFOR if it is in the public interest, "including shareholders of the electric company."[67] The MYP's investments and proposed ROE are supportive of the Company's financial health and ability to attract investors. A financially sound utility benefits not just Pepco and its investors, but has direct benefits for customers and other stakeholders, allowing the Company to invest at the pace necessary to support the District's climate and decarbonization goals as well as to maintain the essential safety and reliability of the distribution system in the District.[68] The Company's proposed ROE represents a reasonable assessment of investors' required rate of return for utilities similar to Pepco given the current capital market.[69] Unless there is a reasonable expectation that investors will have the opportunity to earn returns commensurate with the underlying risks, their capital will be allocated elsewhere, threatening the Company's financial integrity, and investors will demand an even higher rate of return.[70] Importantly, a financially healthy utility reduces borrowing costs and benefits customers through lower rates.[71]

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[66] PEPCO (A): O'Donnell Direct at 10:2-7.
[67] D.C. Code § 34-1504(d)(2); AFOR Order at ¶6.
[68] PEPCO (2A): O'Donnell Supp. Direct at 4:13-18.
[69] PEPCO (A): O'Donnell Direct at 40:20-22.
[70] Id. at 40:17-20.
[71] See e.g., PEPCO (A): O'Donnell Direct at 40:10-13 (describing how an update to the Company's billing determinants improves financial health and credit metrics, reducing borrowing costs, which leads to lower customer rates).

e. The MYP advances the quality, availability, and reliability of regulated utility services for customers, the environment, and the community and is quantifiable.

The investments that the Company is making as part of the MYP benefit customers. The on-going Capital Grid project strengthens reliability and resiliency, supports residential and commercial development in the District, and lessens the impact of major storms.[72] In fact, 2023 was the warmest year on record and the Company saw severe storms as a result.[73] Indeed, in 2023, the Company experienced its first Major Service Outage event since 2018, exclusively from strong summer thunderstorms and damaging winds.[74]

With more people working from home, customer expectations for reliability are higher.[75] For example, the upgrade of the Benning Substation 41 will harden that substation to continue to provide reliable power to several critical downtown substations by increasing the reliability and operational flexibility of the 69kV system supplying these substations for 69,251 customers.[76] The Company's Downtown Resupply, proposed replacement of 34kV underground feeders and conversions from 4kV to 13kV, will update aging infrastructure and improve reliability.[77] The Paper-Insulated Lead Covered Cable Replacement Program and replacement of oil filled cable involves the installation of more environmentally supportive equipment.[78] The Customer Flight Path will enhance the customer's online experience in billing and payments, managed account services, and start, stop, and move requests, enable large commercial customers to obtain

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72 PEPCO (H): Cantler Direct at 35:8-17.
73 PEPCO (4H): Cantler Rebuttal at 7:6-9.
74 Id. at 7:9-11.
75 PEPCO (A): O'Donnell Direct at 15:11-14.
76 Id.at 40:16-22.
77 Id. at 38:8-39:6; PEPCO (H)-2 at 11.
78 PEPCO (H): Cantler Direct at 37:15-21.

awareness of energy saving programs, provide personalized communications during and after power outages, and allow limited income customers to proactively manage their energy use, and assist them in identifying available energy assistance programs.[79] The Company provided internal project approval presentations that detail the customer, environmental, and social benefits of this work.[80] These are quantifiable investments that advance the quality, availability, and reliability of distribution service to the benefit of District customers.

f. The MYP advances the District's economy.

This MYP also advances economic development in the District. By providing transparency into planned investments over the MYP term, stakeholders, such as diverse and local suppliers, are better positioned to determine their hiring needs to support the Company in execution of its capital plan[81] and parties and the Commission are able to confirm in advance that the Company's investments align with the District's and the Commission's goals.[82]

As discussed in the Rebuttal Testimony of Company Witness McClure, the Company's ability to operate under an MYP enhances its ability to enter into longer term contracts with suppliers and continue to invest in the economic development of the communities it serves.[83] Within the scope of the MYP to date, Pepco has awarded over 750 contracts to diverse suppliers totaling over $763 million. As was noted in Pepco's Pre-Hearing Brief, longer-term planning that an MYP allows creates opportunities for the Company to enter into longer-term contracts with its

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79 PEPCO (J): Hightower Direct at 40:22-42:15.
80 PEPCO (H)-3 (Confidential).
81 PEPCO (M): McClure Rebuttal at 6:7-11.
82 PEPCO (A): O'Donnell Direct at 45:5-6.
83 *See generally*, PEPCO (M): McClure Rebuttal.

vendors.[84] This fact was reflected in the community testimony, where a contractor representative from National Utility Contractors Association testified that "[f]or contractors, they need a ramp-up, . . .if it's a multiyear plan, they have time to hire and to get their. . .infrastructure in place so that they can do the job. . .So I would be more for the multiyear plan."[85] A representative from the National Association of Minority Contractors similarly testified that "it's best to have a three-year plan because then you have the opportunity to design and implement the services and support that needs to be given to the community because most of the things are not one-year events."[86] Of note, approximately 40% of the total project spend from the Company's Capital Grid project was with Tier 1 Certified Business Enterprises.[87]

As stated in the analysis of economic benefits prepared by NERA Economic Consulting that the Company included as an exhibit to its testimony, Pepco budgets $4.2 billion in total nominal capital spending for distribution and transmission projects, and 21% of that, or $908 million, is investment spend from vendors, employees, and services physically located in the District of Columbia.[88] Distribution related capital spending is expected to create over 3,800 full time equivalent jobs in the District and over $580 million in value added GDP.[89] These represent measurable benefits to the District's economy through spending, job creation and support of the diverse supplier community.

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[84] PEPCO (A): O'Donnell Direct at 45:11-14.
[85] March 27, 2024 Evening Public Hearing Tr. at 35-36
[86] Id. at 36.
[87] PEPCO (4H): Cantler Rebuttal at 21:8-10.
[88] PEPCO (A)-1 at 2.
[89] Id.

g. The MYP fosters transparency

The Company provides the Commission, customers and stakeholders transparency into the forward-looking plan detailing the investments the Company proposes to make from 2024-2026.[90] Parties and the Commission review that plan and can confirm that the Company's investments align with the District's and the Commission's goals. This also enhances Commission oversight through advanced review of the Company's total capital spending plan and its operational costs, coupled with annual reporting and reviews of certain variances from the MYP's approved levels.[91] Furthermore, the Company enhanced the information provided in its Construction Report, PEPCO (H)-2, to provide more transparency for projects that are allocated between Maryland and the District by providing specific, detailed project sheets for all allocated projects with a budget of $1 million or more.[92] The MYP provides the transparency envisioned by the Commission.

2. The Company's prior MYP in FC 1156 provides the benefits that the AFOR Order anticipated and meets the AFOR Order guidelines.

As detailed in the Supplemental Direct Testimony of Company Witness O'Donnell, many of the benefits anticipated under the FC 1156 MYP have been realized. First, Pepco met its commitment to provide more detailed information on its capital investment plans and business plans and it made those investment plans known in advance, rather than after the fact as in a traditional rate case.[93] As the Company committed to do in FC 1156, it provided details on any significant variances in capital investments and O&M costs from what had been projected at the

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90 PEPCO (A): O'Donnell Direct at 30:20-22.
91 Id. at 45:5-9.
92 PEPCO (H): Cantler Direct at 20:2-9. In prior Construction Reports, Pepco has provided information related to allocated projects in a spreadsheet following the individual, detailed project sheets. *Id*. at 20:5-6.
93 PEPCO (2A): O'Donnell Supplemental Direct at 5: 8-15.

beginning of the plan.[94] This information provided an opportunity for Commission review and assessment if affirmatively requested by any party. Another benefit of the FC 1156 MYP was that it provided rate predictability for customers during the term of the MYP.[95] This certainty of distribution rates assisted customers in overall budgeting because they were assured that new rates would not go into effect in 2023 following the MYP period and they also knew what rate increases had been approved by the Commission over the course of the MYP.[96]

In addition, the MYP structure allowed for more timely recovery of investments, allowing the Company the opportunity to earn close to its authorized return on equity.[97] As Company Witness O'Donnell detailed, the Company historically has not earned close to its authorized ROE prior to FC 1156. A financially sound utility company benefits not just Pepco and its investors, but has direct benefits for all stakeholders, allowing the Company to invest at the pace necessary to support the District's climate and decarbonization goals as well as to maintain the essential safety and reliability of the distribution system in the District.[98] The structure of the MYP adopted in FC 1156 allowed for more timely recovery of investments over the term of the MYP than a traditional, historic test year rate case would.[99]

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94 *Id*. at 6:1-7. The Company notes that no party used the reconciliation process to seek Commission review regarding the variances from plan that were reported or to request a hearing. If the Company had been over-earning, which it was not, the FC 1156 MYP reconciliation process would have allowed the Commission to adjust rates in response. *Id*. at 9:15-20.

95 *Id.* at 6:9-10.

96 *Id*. at 6:9-13.

97 *See* PEPCO (A): O'Donnell Direct at 38:9-39:2 ("Pepco had a well-documented history of earning less than its Commission-authorized ROE under traditional cost-of-service ratemaking. On average, over the five years preceding the filing of FC 1156, Pepco's earned ROE was 2.74% less than its Commission-authorized ROE. Indeed, at the time Pepco filed its MYP in FC 1156, the Company's unadjusted earned ROE was only 5.81%, 3.72% below Pepco's authorized ROE").

98 PEPCO (2A): O'Donnell Supp. Direct at 4:13-18.

99 PEPCO (2A): O'Donnell Supplemental Direct at 4:13-16.

The MYP also encouraged spending with diverse suppliers. To date, Pepco has awarded over 750 contracts to diverse suppliers, totaling $763 million.[100] In calendar year 2022, Pepco's $352 million spend represented a 10% gain in purchases from diversity certified suppliers over 2021, a quantifiable benefit to the diverse supplier community, enhanced by the Company's ability to have more predictable long-term cost recovery.[101]

Another promised benefit resulting from the FC 1156 MYP is a reduced frequency in filing rate cases. The Commission affirmed this point in its order on reconsideration in FC 1156:

> The Commission believes that maintaining the status quo of traditional rate cases would result in more frequent resource-intensive rate proceedings, given the significant capital investments the Company currently undertakes, which is part of the reason the Commission advanced consideration of alternative forms of regulations AFORs. The Commission remains convinced that an MRP that sets rates for several years will in future years greatly reduce the regulatory burden on the Commission, OPC, and all stakeholders.[102]

3. The AFOR Order that provided a framework for the review of the FC 1156 MYP continues to be applicable and provides a reasonable framework for this proceeding.

The Commission developed a comprehensive record in FC 1156 to create a robust framework for the evaluation of AFORs. That framework was detailed in the Commission's AFOR Order, and should serve as the basis for evaluation of Pepco's proposed MYP in this proceeding. As explained in the Direct Testimony of Company Witness O'Donnell, the proposed MYP conforms with the AFOR Order framework, as is demonstrated in the direct testimony of the Company's witnesses.[103]

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100 PEPCO (M): McClure Rebuttal at 5.
101 PEPCO (2A): O'Donnell Supplemental Direct at 14:6-14.
102 FC 1156, Order No. 21042 at ¶82.
103 *See*, PEPCO (A): O'Donnell Direct at Table 3, in which Ms. O'Donnell indicates where each of the ten factors identified in the AFOR Order are addressed in the Company's witnesses' direct testimony.

In order to identify "alternative ratemaking approaches, including PIMs, that further the Commission's MEDSIS goals and the District's energy related objectives," the Commission convened a two-day Technical Conference in October 2019, including experts from the industry, other state regulators and consultants familiar with alternative regulation.[104] The Commission stated that at the end of the Technical Conference, and taking into consideration the comments of interested stakeholders,[105] the Commission would "issue a Policy Order on a framework for alternative forms of regulation in the District of Columbia."[106]

The extensive record the Commission developed in FC 1156 and the conclusions that the Commission drew based on that record were reflected in the AFOR Order and in the subsequent orders adopting the Company's first MYP.[107] The Company appropriately relied on the AFOR Order framework, and its experience operating under the 18-month MYP adopted in FC 1156, to develop the current MYP proposal.[108]

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[104] Among the state commissions that participated in the Commission's Technical Conference were Maryland, Hawaii, Minnesota, and Pennsylvania. Other participants included Regulatory Research Associates, a group within S&P Global Market Intelligence, and the Regulatory Assistance Project, an independent, global NGO advancing policy innovation and thought leadership within the energy community. *See* AFOR Order at n.10.

[105] Comments on the Technical Conference were filed by Pepco, OPC, DC Government, AARP DC, AOBA, IBEW, GRID 2.0, CUB, Sierra Club, WGL, GSA and other interested parties. *See id.,* note 11.

[106] AFOR Order at ¶4.

[107] *See*, FC 1156 Order No. 20755 and Order No. 21042.

[108] The ten guidelines established in the AFOR Order are: (1) the AFOR protects consumers; ensures the quality, availability, and reliability of regulated utility services; and is in the interest of the public, including shareholders of the utility. (2) The AFOR advances the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments. (3) The AFOR's ratemaking mechanisms advance or otherwise align with the District's public policy goals. (4) The AFOR identifies baseline revenue and cost information, and clearly explains what process or mechanism the utility used to project revenues and expenses. (5) The AFOR provides benefits that are measurable, quantitative, and qualitative to customers, as opposed to solely focusing on the AFOR's benefits to the utility. (6) The AFOR impacts the operational incentives of the utility with respect to maintaining a high level of customer service, while fostering productivity and cost control; maintains the financial strength, credit ratings, and financial flexibility of the utility; and helps ensure a consistently high level of energy delivery system reliability, while promoting safe and reliable operations over time. (7) The revenue requirements will be allocated across customer classes over time,

4. *If the Commission determines that any further "lessons learned" evaluation is necessary, it can be completed simultaneously within the term of this MYP.*

OPC and AOBA have argued that the Commission should not permit the Company to proceed with a new MYP before an extensive "lessons learned" proceeding is undertaken to evaluate the FC 1156 pilot MYP.[109] The Commission, however, has stated, and affirmed that it is capable of proceeding with a lessons learned evaluation simultaneously with a new MYP for Pepco.[110] The Commission's decision to proceed with a new MYP, consistent with its direction to the Company in Order No. 20755,[111] is also consistent with decisions from Maryland.[112]

Commission adoption of applicable regulations or completion of an evaluation of the FC 1156 MYP was not required before Pepco filed its MYP.[113] The Company followed the

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and how rate design issues within customer classes will be handled over time, in a just and reasonable manner. (8) The risk of over-earning a utility's authorized return will be mitigated during the duration of AFOR for the benefit of the customers, while also preserving the Commission's ability to conduct cost prudency reviews as needed. (9) The AFOR provides an appropriate level of transparency and reporting into the utility's operational and capital plans ensuring that the plans will be maintained during the duration of the AFOR. (10) The AFOR avoids any unreasonable shifting of risk to utility customers. AFOR Order at ¶6.

[109] *See e.g.*, OPC Comments Regarding A Procedural Schedule, filed June 23, 2023; and OPC's Request For Reconsideration of Order No. 21886, filed Aug. 28, 2023.

[110] FC 1176, Order No. 21886 at ¶1. See also Order No. 21886 at ¶¶24, 29; Order No. 21955 at ¶¶ 11, 12 (denying OPC's motion for a stay and renewed motion for stay).

[111] FC 1156, Order No. 20755, at ¶142 f. (Pepco prohibited from filing a new MYP until January 2, 2023).

[112] In Maryland, the MYP pilot utility was Baltimore Gas and Electric Company (BGE). *See* Md PSC Case No. 9618, Order No. 89482. When BGE filed its second MYP application, the MD People's Counsel argued that the lessons learned proceeding on the pilot MYP should be completed in advance of the next MYP being adopted. The Maryland Commission denied that request. Instead, the Commission reiterated that while it would complete its lessons learned proceeding at the conclusion of BGE's first MYP, it would nonetheless proceed with BGE's then current rate case as a new MYP. *See*, Application of Baltimore Gas and Electric Company for an electric and gas multi-year plan, Maryland Public Service Commission Case No. 9692, Order on Application for A Multi-Year Rate Plan, Order No. 90948 at 10-12 (December 14, 2023). The Commission reiterated that since there were options for an "off ramp" built into the MYP structure, if the lessons learned proceeding indicated that there were extraordinary circumstances warranting modification or termination of the MYP, then the Commission could exercise that off ramp. The Commission noted that such an exit from the second MYP would only be warranted if "extraordinary circumstances [ ] call into question whether the existing rates are just and reasonable." *Id.* On August 15, 2024, in Case Nos. 9618 and 9645, the Maryland Commission issued a notice convening that lessons learned proceeding. In the instant case, Pepco's case is the pilot, and if the Commission desires a lessons learned process, the Commission can take a similar approach here and proceed with approval of this MYP, while at the same time considering lessons learned in parallel.

[113] *See* question raised in transcript of July 30, 2024 Legislative Style Hearing ("Tr.") at 33-38.

Commission's directives regarding the timing of its new MYP application. In Order No. 20755, the Commission stated that a new multiyear rate plan could be filed as early as "January 2, 2023, with rates to be effective no earlier than January 1, 2024."[114] Nothing in Order No. 20755, or any other order issued subsequently, made the Company's filing of an MYP application contingent on the Commission's adoption of regulations regarding MYPs.

To the contrary, in Order No. 21886, the Commission, after noting that it might "require multiple rate proceedings to fully implement AFOR,"[115] stated "we do not believe we should delay consideration of the Company's MYP request."[116] Additionally, the Commission in the AFOR Order adopted a robust AFOR framework that is a reasonable and well thought out guide.

Moreover, the concept of the Commission developing new processes and requirements through the rate case process and then carrying that knowledge forward to follow-on rate proceedings is nothing new. The Commission has repeatedly developed new processes and standards and made them applicable during subsequent cases. The development and evolution of the current Construction Report is just one readily identifiable example.[117]

As discussed in the testimony of Company Witnesses O'Donnell, Leming, and Cantler there have already been important lessons learned under the FC 1156 MYP and these lessons

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[114] Order No. 20755 at ¶476aa.
[115] Order No. 21886 at ¶22 (quoting AFOR Order at ¶86.)
[116] *Id*. at ¶23. See also FC 1176, Order No. 21903 at ¶8.
[117] In Order No. 16930 in FC 1087, the Commission directed Pepco to file certain specific information regarding its distribution construction program with its next base rate application. Order No. 16930 at ¶485, as clarified by FC 1087, Order No. 17027 at ¶27. In compliance with the Commission's directive, the Company filed a detailed Construction Report with its application in FC 1103. In Order No. 17424, the Commission found that the Company had complied with its directives in Order No. 16930 and directed that the Company make certain further refinements to the report in its next base rate case. FC 1103, Order No. 17424 at ¶519. These refinements were incorporated into the Construction Report Pepco filed in FC 1139. In FC 1139, the Commission found that the Construction Report the Company had filed complied with the various directives the Commission had issued over a series of prior rate cases.

learned have been factored into the current MYP. For example, as discussed by Company Witness Leming, the use of the Company's LRP best reflects actual plans and projects that Pepco will undertake in the District. An escalator factor is not aligned with that reality, and fails to account for the year-to-year deliberate planning variations that could not be captured by an index.[118] As counsel for the Company noted in the Legislative Hearing, several lessons learned from the experience under the FC 1156 MYP have informed the Company's proposed MYP in this proceeding, including, e.g., improvements to the billing determinants process.[119] Nonetheless, while the Company has addressed certain lessons learned under the prior MYP, it is open to incorporating additional lessons learned as appropriate.[120] If the Commission determines that any further "lessons learned" evaluation is necessary, as the Commission has recognized, it can be completed simultaneously within the term of the MYP that should be adopted in this proceeding.[121]

5. *Stay Outs distort the value of MYPs and result in greater increases in RY1 of a subsequent MYP.*

Although none of the other parties advocated for a stay out in their prefiled testimony, the Commission raised the topic at the legislative style hearing.[122] Adoption of a stay out would distort the workings of the MYP mechanism and undercut some of the benefits that an MYP provides.

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118 See PEPCO (2A): O'Donnell Supplemental Direct at 20:18-19. See also PEPCO (B) Leming Direct at 9:7-20. As Witness Leming states, "The LRP reflects the Company's best current estimates regarding the specific distribution programs and initiatives Pepco will undertake in the District and considers impacts of inflation and supply chain issues during the 3-year term of the MYP. An escalation factor approach, however, which was used for FC 1156, is not able to reflect such year-to-year changes and thus is not the optimal solution to best align the Company's rates (and revenues) with the costs that it will incur to provide electric distribution service to customers in the District." *Id*. at 9:14-20.

119 Tr. at 17-18.

120 Tr. at 18-19.

121 *See supra* at footnote 110. The lessons learned proceeding from the Company's prior rate case in FC 1156 could be considered in parallel with the implementation of the Company's MYP in FC 1176.

122 Tr. at 152-153.

For example, a stay out disrupts the cadence of MYPs so that a new MYP cannot go into effect at the conclusion of the prior MYP. This results in customer rates being more significantly impacted in the future, as they will experience two or more years' worth of rate base and cost growth at once, as opposed to spreading those increases over multiple years. Company Witness Leming estimated the stay out in FC 1156 added approximately $29 million to the RY1 of the current proposed MYP, which represented a 57% increase to the Company's requested cost of service in 2024.[123] This impact could effectively be considered a lessons learned from FC 1156. A stay out provision also creates regulatory lag and lengthens the cost recovery period, which reduces rate predictability,[124] reducing one of the benefits of MYPs identified by the Commission. Indeed, a seamless transition from one MYP to another MYP was an important element recognized by the Maryland Public Service Commission in their development of an MYP framework, when it found it "necessary to prevent [MYP] rates from automatically extending beyond the authorized duration" of the MYP and that the pilot utility must file a new rate case prior to the conclusion of the MYP, with the new rate case having an effective date that would take effect immediately at the close of the final year of the pilot MYP.[125]

For these reasons, the Commission should not adopt a stay out in connection with the proposed MYP.

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[123] PEPCO (B): Leming Direct at 11:14-20.
[124] PEPCO (B): Leming Direct at 11:9-11.
[125] Maryland Public Service Commission Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company, Order No. 89482 at 30.

B. Pepco's Projected Capital Expenditures and Plant Additions through the 3-Year Term of the MYP Are Foundational to a Climate Ready Grid.

As part of its Application, Pepco submitted its Construction Report,[126] which includes projected capital expenditures and plant additions through the MYP period.[127] Company Witness Cantler testified to the contents and provided an overview of the Construction Report and Pepco's capital construction program.[128] She indicated how the Company's capital investment strategy reflects the Company's focus on continuing to pursue solutions to climate change through enhancing grid performance in an on-going effort to continually provide world class customer experience that prioritizes both social equity and affordability.[129] The capital projects in the Construction Report will support initiatives like reliability and resiliency improvements that are intended to promote a pathway towards a Climate Ready Grid and will provide benefits to District customers.[130]

Although, as discussed further below, some parties challenged particular capital projects, no party challenges that the Construction Report filed in this proceeding is consistent with the Commission's prior directives. OPC Witness Mara asserts that Pepco's capital investments are

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126 PEPCO (H)-1 through (H)-3. Consistent with previous rate cases and Commission directives, Pepco provided its five-year capital budget and forecast through 2026. *See, e.g.,* FC 1103, Order No. 17424 at ¶¶537-539. Historically, Pepco presented its capital expenditures in three main categories: load, reliability, and customer-driven; however, Pepco is now defining and presenting capital spend by its twelve Executive Categories, as this provides a more detailed and descriptive breakout of Pepco's annual capital budget. PEPCO (H): Cantler Direct at 13:3-6. Company Witness Cantler provided a description of the general scope of work within each Executive Category as well as the Company Witness whose Direct Testimony supports the category's budgets and initiatives. PEPCO (H): Cantler Direct at Table 2.

127 Company Witness Cantler detailed the processes and procedures the Company uses for developing Pepco's capital construction budget. PEPCO (H): Cantler Direct at 22:18-25:10.

128 PEPCO (H): Cantler Direct at 18:10-20:17.

129 PEPCO (H): Cantler Direct at 57:4-6.

130 PEPCO (H): Cantler Direct at 57:7-11. Company Witness Cantler provided an overview of the strong reliability performance Pepco has achieved and explained that continued investment in reliability is imperative to maintaining consistent performance levels as new system performance issues emerge, equipment ages, and weather varies from year to year. *Id*. at V.

business as usual and should not be classified as Climate Ready Grid investments.[131] However, this ignores that the investments included in the MYP are initiating the foundational framework that will enable and promote energy transformation in the District consistent with legislative and regulatory policy.[132] This MYP's investments are a step in Pepco's long-term strategy to establish a Climate Ready Grid, but the Company has not claimed that this process will be completed in a single 3-year period. To the contrary, as Company Witness Cantler explained, the pathway to a Climate Ready Grid requires essential core investments, such as Pepco is proposing in the MYP, to be in place to support the principles of adequate electric distribution service, system reliability and resiliency.[133]

The Climate Ready Pathway covers all of Pepco's operations for the period through 2026. In addition to advancing the District's clean energy and decarbonization goals the Company's investments necessarily must include those needed to maintain the distribution system and allow it to operate in a safe and reliable manner so as to serve customers.[134] As Company Witness Cantler emphasized:

> Continued investments in reliability and resiliency are paramount to establishing a pathway to a Climate Ready Grid because they enable the Company to proactively maintain and enhance the system to guard against negative customer impact associated with the potential of equipment failure due to age, obsolescence, etc. while also maintaining a system that can operate through variable weather and uncontrollable events from year to year. It is critical that the Company continues to invest in these programs and projects to address those issues throughout this

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131 OPC (E): Mara Direct at 8-9

132 PEPCO (4H): Cantler Rebuttal at 6:14-7:4.

133 PEPCO (4H): Cantler Rebuttal at 6:17-19. See also id. at 7:3-23, noting how Pepco's grid modernization efforts align with a Climate Ready Grid, including greater visibility into outage information, support for DER, and EV initiatives to facilitate the transition to zero emissions vehicles. Reliability and resiliency are integral parts of a climate ready grid, and allows the Company to better adapt to changing conditions. Id. at 8:3-9:12.

134 PEPCO (4H) at 8:11-18. *See also* PEPCO (B): Leming Direct at 5:14-17 ("additional capital investments and on-going costs are necessary to maintain and modernize the distribution grid so that the Company can continue providing safe and reliable service to customers.")

MYP by replacing aging equipment and repairing the damage caused by storms and extreme heat to its system.[135]

Examples of such projects include the following:

- Capacity expansion as part of the continuation of the Capital Grid project, which will strengthen resiliency and reliability in the District by upgrading three substations and by constructing a new substation to serve growing residential and commercial load in the Mount Vernon and North of Massachusetts Avenue neighborhoods.
- Continuation of Downtown Resupply, involving installation of new distribution conduit and proactively replaces aging and infrastructure approaching functional obsolescence.
- Projects to address aging infrastructure by replacing paper-insulated lead covered cables with newer Ethylene Propylene Rubber.
- Replacing 110 miles of aging oil filled cable with 40 miles of new, more reliable, and environmentally friendly cable.
- Fire protection replacement projects to increase safety of employees and customers and protect critical equipment in the event of a fire.
- Phase out of the 4kV system to 13kV, driven by high load growth, need for additional feeder capacity, and to mitigate future reliability concerns.[136]

Such investments are also foundational to the pathway to a Climate Ready Grid. As Company Witness Cantler explained, Pepco cannot move forward and/or forge a pathway anywhere, unless it first has reliable and resilient core investments and infrastructure in place.[137] For example, improving grid resiliency is foundational, but to achieve this requires the replacement of aging and/or infrastructure approaching functional obsolescence as well as the routine and timely performance of corrective maintenance work.[138]

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135 PEPCO (4H) at 8:11-18.

136 Id. at 35:7-14; 38:3-7; 38:16-39:12; 41:3-6.

137 PEPCO (4H): Cantler Rebuttal at 7:12-14.

138 PEPCO (4H): Cantler Rebuttal at 7:18-8:3. In connection with the FC 1156 MYP, the Commission indicated that "[t]he vast majority of Pepco's cumulative rate increase over the term of the Modified EMRP is driven by utility infrastructure investments recently made or ongoing to meet the Commission directed reliability improvements." Order No. 20755 at n.406.

Pepco's MYP incorporates the Company's projected capital investments during the three-year term of the MYP, rather than the use of an escalator as some parties have suggested.[139] The Company provided detailed information regarding its projected capital investments. Because these costs are based on the Company's LRP process, they are reflective of Pepco's actual planned spending during the MYP's 3-year term and consider the impacts of inflation and supply chain issues over this period.[140] By contrast, an escalation factor approach is not able to reflect such year-to-year changes in the programs and initiatives Pepco undertakes and thus is not the optimal solution to best align the Company's rates (and revenues) with the costs that it will incur to provide electric distribution service to customers in the District.[141]

Moreover, as Company Witness Cantler explained, because the MYP process holds the Company accountable to its forward-looking project budgets, Pepco is incentivized to be even more diligent with investment planning by maintaining a stringent process of project authorization requirements so that projects are completed on time and within range of the proposed budgets that have been approved for inclusion in the MYP.[142] Finally, because Pepco does not earn a return on any underearning it is authorized to recover through the reconciliation process, the Company has a strong incentive to develop capital investment (and O&M) forecasts that are as close as possible to actual results.[143]

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139 DCG (A): Lane Direct at 5:14-15.
140 PEPCO (B): Leming Direct at 9:14-17.
141 PEPCO (B): Leming Direct at 9:17-20.
142 PEPCO (4H): Cantler Rebuttal at 5:4-15.
143 PEPCO (B): Leming Direct at 9:23-10:2.

Finally, as in prior proceedings, the Construction Report consisted of three parts.[144] PEPCO (H)-1 provides information on the Company's distribution construction program in the format required in Order Nos. 16930 and 17424[145] and presented in similar fashion to the Construction Report Pepco filed in FC 1156.[146] PEPCO (H)-2 provides actual capital expenditures for 2022 as well as budgeted capital amounts for 2023-2026 by ITN as well as the problem statement, solution, justification, and alternatives considered for each ITN.[147] The Company enhanced the information provided in PEPCO (H)-2 to provide more transparency for projects that are allocated between Maryland and the District by providing specific, detailed project sheets for all allocated projects with a budget of $1 million or more.[148] Finally, PEPCO (H)-3 provides a complete listing of all distribution-related expenditures that are projected to close to plant between 2022 and 2026.[149]

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144 PEPCO (H): Cantler Direct at Table 3.

145 In Order No. 16930 in FC 1087, as clarified by Order No. 17027, the Commission acknowledged the Company's plan to undertake extensive construction work related to its distribution system in the coming years, and directed Pepco to file certain specific information regarding its distribution construction program with its next base rate application. Order No. 16930 at ¶485, as clarified by FC 1087, Order No. 17027 at ¶27. In compliance with the Commission's directive, the Company filed a detailed Construction Report with its application in FC 1103. In Order No. 17424, the Commission found that the Company had complied with its directives in Order No. 16930 and directed that the Company make certain further refinements to the report in its next base rate case. FC 1103, Order No. 17424 at ¶519. These refinements were incorporated into the Construction Report Pepco filed in FC 1139. In FC 1139, the Commission found that the Construction Report the Company had filed complied with the directives in Order Nos. 16930 and 17424. FC 1139, Order No. 18846 at ¶546. Additionally, the Company hosted a technical conference on June 2, 2023, to discuss the construction report and take questions. PEPCO (4H) Cantler: 31:15-17. AOBA, OPC and DCG attended this meeting. Id.

146 PEPCO (H): Cantler Direct at 18:11-14.

147 PEPCO (H): Cantler Direct at 18:15-20.

148 PEPCO (H): Cantler Direct at 20:2-9. In prior Construction Reports, Pepco has provided information related to allocated projects in a spreadsheet following the individual, detailed project sheets. *Id*. at 20:5-6.

149 PEPCO (H): Cantler Direct at 19:1. PEPCO (H)-3 reflects: (1) completion of the capital work from PEPCO (H)-2 and the assets placed in service; and (2) AFUDC is applied; however, it does not reflect the application of the allocations to assign assets that are shared with other customers to the appropriate line of business for recovery (i.e. Pepco MD or transmission customers). *Id*. at 19:2-6.

The Commission should find the Company's Construction Report complies with Commission directives and the capital expenditures and capital additions set forth therein are reasonable and appropriate.

C. The Company's Proposed Capital Additions Are Reasonable and Most Are Not Disputed by The Other Parties

Most of the capital projects identified in the Construction Report as being projected to close before the end of the term of the MYP and whose costs are reflected in rates are not challenged by the other parties. Only OPC and AOBA challenged any of these capital investments.

1. The Company has excluded the majority of the capital projects challenged by OPC.

OPC identified a few capital projects that it argued should be excluded because they were misclassified,[150] misallocated[151] or could be deferred under load forecasts prepared following the submission of Pepco's MYP Application.[152] As discussed in the Rebuttal Testimony of Company Witness Cantler and Leming, the Company agreed that most of these projects were appropriately excluded from the MYP. They were removed through RMA 29.[153]

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150 ITN 77270 - High-Side Bus Land should not have been included in PEPCO (H)-2 as the land purchase was inadvertently marked as going in service upon purchase rather than land held for future use which is not included in rate base. PEPCO (4H): Cantler Rebuttal at 24:21-25:3.

151 ITN 72730 – National Harbor Sub - New 69/13kV Dist Sub was inadvertently tagged as sub transmission and should not have been included in this rate case. The distribution costs of ITN 74120 – White Flint New Substation 69/13kV, should have been directly assigned to Pepco's Maryland jurisdiction and the subtransmission costs allocated between the District and Maryland using the AED-NCP allocator. PEPCO (4H): Cantler Rebuttal at 26:8-19.

152 The projects appropriately deferred to beyond the MYP period are: ITN 74085 – Waterfront Substation Install 5th Transformer; ITN 77272 - 230kV High-Side Bus; ITN 62900 - Alabama Ave. Sub 136 Feeder 15166 Battery Substation; ITN 62935 - Alabama Ave. Sub 136 Feeder 15166 Battery Distribution; ITN 63208 - Alabama Ave. Sub 136 Feeder 15166 Battery Fiber/Telecom; and ITN 67364: - Mt. Vernon Battery Energy Storage System. PEPCO (4H): Cantler Rebuttal at 24:17-25:18.

153 PEPCO (3B): Leming Rebuttal at 39:13-40:7.

The only exception were the 14 projects included within the Downtown Resupply project that OPC challenged.[154] However, of these 14 projects identified by OPC,[155] only 4 are projects that are projected to close and be placed in service during the 3-year term of the MYP (2024-2026) and thus are included in the Company's revenue requirement for the MYP.[156] Company Witness Cantler detailed why each of these capital investments is an essential project that is necessary to the future success of both the Downtown Resupply and Capital Grid projects that are being implemented to improve the overall integrity of the downtown grid through an integrated network that avoids costly maintenance and time consuming repairs.[157]

2. *AOBA's challenges to certain specific capital projects in the Construction Report should be rejected.*

AOBA Witness B. Oliver makes the unreasonable claim that the 2022 Annual Information Filing in FC 1156 shows that Pepco underspent its budget for ITN 75093 – New Business Commercial by $9.2 million and argues it is therefore appropriate to impose a reduction of $9.2 million across all budgeted years within the MYP.[158] As Company Witness Cantler explained, AOBA's suggestion is based on a misunderstanding of the data being compared. For example,

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154 The 14 projects identified by OPC Witness Mara are: ITN 68678 - L Street Rebuild Distribution Work; ITN 72137 - L Street Sub Capacity Expansion; ITN 80130 Pepco DC Buzzard to F Street; ITN 80425 Pepco DC F Street to Georgetown; ITN 80427 Pepco Champlain to L Street 69kV; ITN 80740 Pepco DC Champlain to F Street; ITN 68612 Pepco DC L Street T1 Replacement: ITN 68613 Pepco DC L Street T2 Replacement: ITN 68614 Pepco DC L Street T3 Replacement; ITN 68615 Pepco DC L Street T4 Replacement; ITN 71630 F Street Sub Rebuild (69kV); ITN 71631 F Street Sub Rebuild; ITN 73368 Champlain Bypass; and ITN 71012 Champlain – New 69kV Sub. PEPCO (4H): Cantler Rebuttal at Table 3.

155 For the 10 projects that are not projected to be placed in service during the term of the MYP, as discussed in Section D below, OPC inappropriately suggests the removal capital expenditures from rate base as they are incurred even though these amounts were not included in rate base in Pepco's application. PEPCO (3B): Leming Rebuttal at 21:5-9.

156 PEPCO (3B): Leming Rebuttal at 21:20-22:5 and Tables 8 & 9. The 4 projects included in the MYP's proposed rates are: ITN 68678 - L Street Rebuild Distribution Work; ITN 72137 - L Street Sub Capacity Expansion; 68615 Pepco DC L Street T4 Replacement; and ITN 73368 Champlain Bypass. PEPCO (4H): Cantler Rebuttal at Table 4.

157 PEPCO (4H): Cantler Rebuttal at 19:9-20:13.

158 AOBA (A): B. Oliver Direct at 77:7-10.

AOBA Witness Oliver comparison of projects in PEPCO (H)-2 and the Company's Final Reconciliation in FC 1156 and his assertion that differences in the amounts "raise serious concerns regarding the accuracy and reliability of the information Pepco has provided with respect to the Company's actual cost experience,"[159] is a flawed assertion because such a comparison will never match as PEPCO (H)-2 shows "planned capital expenditures," whereas the Final Reconciliation filing shows "capital additions."[160] This issue is discussed further in Section D below.

Rather than an underspend of $9.2 million as AOBA claims, Pepco actually only underspent its budget in 2022 of $24.8 million for ITN 75093 by approximately $1.6 million, a 6% differential.[161] In addition to significantly miscalculating the amount of underspend based on the difference between planned capital expenditures versus capital additions, AOBA's suggestion also inappropriately relies on only one year of data to make a change that will affect the budget for a three-year period.[162] Finally, the recommendation is based on perceived negative overall growth in the number of commercial customers but does not consider the need for new business connections for commercial customers nor does it account for the specific projects that will be constructed.[163] AOBA's suggested disallowance is erroneous and should be rejected.

AOBA Witness B. Oliver also proposes approximately $167 million in suggested disallowances across twelve projects included in the Company's proposed MYP based on his inability to match the capital budgets for these projects with those in the Project Concurrence

159 AOBA (A): B. Oliver Direct at 78:23-25.
160 PEPCO (4H): Cantler Rebuttal at 22:16-21.
161 PEPCO (4H): Cantler Rebuttal at 23:3-4.
162 PEPCO (4H): Cantler Rebuttal at 23:15-16.
163 PEPCO (4H): Cantler Rebuttal at 23:16-24:2.

Committee ("PCC") decks provided in Pepco's response to AOBA DR 7-25.[164] As Company Witness Cantler explained, AOBA is inappropriately comparing preliminary budgets presented during project inception with the project budgets presented in the Construction Report in PEPCO (H)-2 under the erroneous presumption that they would be similar.[165] Many of the project budgets that are reflected in the PCC decks provided in Pepco's response to AOBA DR 7-25 reflect preliminary and early project cost estimates initiated at the onset of project scoping. Like all budgets, these project budgets become more refined as the project escalates through project authorization toward eventual project execution.[166] The final budgets and details for the Company's capital investment projects in the MYP are included in PEPCO (H)-2.[167]

AOBA's comparison is inappropriate and is not a reasonable basis to disallow $167 million of Pepco's capital investment plan. It ignores the internal process and procedures explained by Company Witness Cantler in Direct Testimony that Pepco follows for the authorization of capital project and the development of project budgets.[168] AOBA's proposed disallowance of $167 million is unreasonable and should be rejected.

Moreover, AOBA's suggestion erroneously removes capital expenditures without first undertaking an examination of the Company's testimony to determine whether the project was projected to close to electric plant in service during the term of the MYP and thus was included in Pepco's revenue requirement.[169] AOBA further compounded the error by proposed the

164 AOBA (A): B. Oliver Direct at 73:8-74:10; AOBA (A)-5.
165 PEPCO (4H) at 11:3-12:7.
166 PEPCO (4H): Cantler Rebuttal at 11:11-17.
167 PEPCO (4H): Cantler Rebuttal at 12:5-6.
168 PEPCO (H): Cantler Direct at III. *See also* PEPCO (4H): Cantler Rebuttal at 12:10-21.
169 PEPCO (3B): Leming Rebuttal at 23:3-7. This issue is discussed under Section D below.

disallowance of entire project costs, rather than the portion that would be attributable to Pepco DC Distribution.[170]

Finally, AOBA's arguments here are similar to arguments that AOBA made in FC 1139 challenging Pepco's O&M account costs because there were variances. The Commission rejected AOBA's arguments in FC 1139. In language equally applicable here, the Commission addressed the burden of persuasion in a rate case and explained why AOBA's arguments failed to meet that burden. The Commission stated:

> In accordance with D.C. Code § 2-509(b), the utility, as a proponent of its cost recovery, has the burden of persuasion. However, other parties who challenge the utility's proposals have a burden to present credible, concrete challenges to the utility's proposals. They may tender appropriate data requests to the utility and use that data to formulate their arguments about whether the utility's proposals are justified in testimony presented by their witnesses.
>
> AOBA has identified some variances in costs in this case compared to Pepco's expenditures in Formal Case No. 1103. The mere identification of variances in expenditures alone falls short of the reliable, probative and substantial evidence standard that is necessary to create serious doubt regarding Pepco's cost proposals. Additionally, AOBA's general statement failed to identify the specific expenses it questioned nor rebuts the Company's assertion that its operating expenses in this case are just and reasonable. Based on these facts and applicable legal standards, AOBA's recommendations regarding Pepco's increases in O&M expenditures are rejected[171]

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170 PEPCO (3B): Leming Rebuttal at 23:10-12. For example, AOBA recommends the disallowance of $72.5 in capital expenditures from 2023 through 2026 for ITN 65553 (Benning Substation 41 69kV GIS); however, PEPCO (H)-2 indicates that this project is not projected to go into service until December 2027, following the MYP. None of these expenditures would therefore have been reflected in Pepco's revenue requirement in this proceeding. Furthermore, because this is a subtransmission project, only 40.31% of Pepco's capital spend ultimately will be allocated to Pepco DC distribution rates. PEPCO (3B): Leming Rebuttal at 23:15-20.

171 FC 1139, Order No. 18846 at ¶¶225-226. *See also* FC 1139, Order No. 19130 at ¶57:

> AOBA's general statements about large increases in various accounts are insufficient because AOBA failed to identify specific expenses that it questioned. Nor did AOBA submit specific evidence supporting why the variances in expenses were inordinately high, or rebut Pepco's evidence that its operating expenses in this case are just and reasonable. Without identifying specific expenses and a particular basis upon which the Commission should reject these expenses in its testimony, AOBA failed to meet a well-established standard for creating serious doubt regarding Pepco's O&M expenses in this case.

3. The Company is experiencing load growth, which necessitates capital investments.

At the hearing, the Commission suggested that the grid can support increased load from electrification.[172] One important clarifying point regarding the study in FC 1167, is that it is assessing *system-wide* impacts of electrification. However, investment in load growth projects is not determined based on system-wide load; rather, it is determined by analysis at the feeder, transformer and substation level.[173] In other words, load growth is location specific and based on localized grid conditions and needs.[174] Pepco did anticipate local capacity needs and enhancements associated with broad electrification.[175]

Parties have incorrectly argued that the MYP's capital investments are not needed when the number of customers and system-wide load are forecasted to decline. The Company's forecast demonstrates otherwise. Exhibit (H)-1 shows the substation peak forecast for 2024-2032, which shows an upward trend.[176] Furthermore, the distribution system is not static; it requires continual investment if it is to meet the needs and expectations of customers as well as support the District's decarbonization goals. The continued investment is necessary to maintain system reliability as well as to harden the system against extreme weather conditions.[177] There are areas within the District that are growing and adding new residential and commercial customers and will need investment to support the associated load growth. For example, the redevelopment of the former Walter Reed Medical Center requires changes to the distribution system serving that area to serve new

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172 Tr. at 42.
173 PEPCO (H-1) at 6.
174 See FC 1167, Pepco Electrification Study Cover Letter at 2 (August 27, 2021); FC 1167, Reply Comments of Potomac Electric Power Company at 58 (September 16, 2022).
175 See FC 1167, Pepco Electrification Study Cover Letter at 2.
176 PEPCO (H)-1 at 11-13.
177 PEPCO (H): Cantler Direct at 37:1-7.

customers.[178] Further, Pepco is converting the bulk of its 4kV system to 13kV, driven by load growth.[179] Additionally, as Company Witness Allis explained, implementation of highly electrified and interactive systems the District's decarbonization goals envision will require technology upgrades and other enhancements to the distribution systems. The distributed, prosumer energy system developing in the District requires a platform that is able to provide electric power to customer's DER as well as receive generation from distributed generation, communicate with the DER to optimize grid and system performance for the benefit of customers, and allow for the future innovation that will benefit customer-side energy systems. Pepco's investments will provide customers with the reliability they expect and deserve while evolving the grid to meet the decarbonization, prosumer and innovation needs the District and our customers desire.

The Company's investment in Advanced Distribution Management System ("ADMS") enables solutions to combat climate change because it will allow customers to incorporate more DER on the distribution system and to interconnect to renewable generators, such as rooftop solar, which support climate goals.[180] ADMS technology also allows for grid stabilization when power fluctuations occur, and as DERs become more prevalent, there is potential for these fluctuations to occur in greater frequency. ADMS technology is designed to communicate and control future DER to mitigate those fluctuations and accommodate for such things as the continued integration of electric vehicle charging stations and rooftop solar.[181] An ADMS platform enables the

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[178] PEPCO (H)-2 at 47.
[179] PEPCO (H): Cantler at 38:17-19.
[180] Id. at 44:14-21. ADMS deploys foundational DER management system capabilities, including DER visualization, DER forecasting, and DER monitoring and control. Id. at 22:1-5.
[181] PEPCO (H): Cantler Direct at 44:14-20.

distribution system to adapt and transform in support of changing customer needs and the market shifts anticipated by grid modernization. The ADMS program drives standardization of business processes and the convergence of multiple, utility specific systems on to a common platform.[182]

4. The Company's cybersecurity and physical security investments are reasonable.

Another important capital investment involves mitigation of cybersecurity and physical security. For example, replacing end-of-life IT is critical to reduce cybersecurity vulnerabilities, as end-of-life hardware and software are often difficult and sometimes impossible to patch with the latest security updates.[183] Examples of cybersecurity risks include loss of industrial control systems, such as Supervisory Control and Data Acquisition (SCADA), malware on Company computer systems, release or corruption of customer information, and loss of data due to natural or manmade disasters.[184] The Company must also protect its physical assets, and accordingly, its capital plan includes funding to safeguard Company assets at the substation-level.[185] This risk is evidenced by attacks on substations experienced by Pacific Gas and Electric and Duke Energy and the attempted attack experienced in the Baltimore Gas and Electric service territory.[186]

The Company has met its burden of persuasion in this case and presented a *prima facie* case regarding the capital investments that are projected to close and be placed in service during the term of the Climate Ready Pathway and whose costs are therefore reflected in the MYP's proposed rates. The Commission should approve recovery of these costs in the rates established for the MYP.

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182 PEPCO (H-2) at 174.
183 Id. at 45:8-13.
184 Id. at 46:20-47:4.
185 Id. at 48:10-19.
186 Id. at 47:11-48:3.

D. Other Parties Have Conflated Pepco's Capital Spending with the Capital Projects that Are Projected to Be Completed During the Term of the MYP and Are Reflected in Rates.

1. *The Parties mischaracterize the projects within the scope of the MYP.*

The testimony of several parties has challenged the Company's capital spending for projects that are not reflected in the MYP's rates as their in-service date will not occur during the 3-year term of the MYP. The parties appear to be conflating Pepco's capital spending with the capital projects that are included in rate base and thus reflected in rates. The Company's capital investments are not included in rate base until the project is complete, placed in service and benefiting customers. Many of Pepco's capital projects have long lead times spanning multiple years. Thus, there may be capital spending budgeted across multiple years on a specific project; however, if that project is not projected to be completed and in service prior to December 31, 2026, that capital spending is not reflected in the rates proposed under the MYP. As Company Witness Leming explained in Rebuttal Testimony:

> As capital expenditures are made, they are recorded to FERC account 107, Construction Work in Progress (CWIP), until the time that those projects are placed in service and closed to FERC account 101, Electric Plant In Service. The Company has not included FERC account 107, CWIP, in rate base in its proposed revenue requirement. This is consistent with ratemaking precedent in the District. As such, the Company has not factored these expenditures into its revenue requirement until the time that projects are completed and closed to FERC account 101.[187]

As a result of conflating capital expenditures with capital additions, the parties inappropriately suggest adjustments to remove capital expenditures from the MYP's rate base when the projects are not projected to be completed and placed in service during the MYP rate

[187] PEPCO (3B): Leming Rebuttal at 21:11-17.

effective period and thus are not reflected in rates.[188] This is fundamentally wrong and contrary to well established Commission precedent regarding the inclusion of capital projects in rates.[189] The Commission should reject these adjustments that improperly seek the removal of capital expenditures from rate base as it is spent.

2. *Pepco's forecasting is appropriate and consistent with best practices of other utilities within Exelon.*

As discussed above, most of the capital projects identified in the Construction Report as being projected to close before the end of the term of the MYP and whose costs are reflected in rates are not challenged by the other parties. Additionally, there may be deviations from the projected timing of capital expenditures on a project. For example, due to a permitting issue, work from the 4th quarter of a year might be delayed to the 1st quarter of the next year. This would result in a variance in capital spending, but the project could still be completed on time and within budget which is when it would be closed to plant and reflected in the Company's rate base. Especially on complex projects that have long lead times, there are numerous factors that can impact the timing of capital spending on a project, most of which are outside of the Company's control, including: significant weather events, unforeseen field conditions, permitting, resource and material availability, supply chain challenges, and new legislation and/or regulatory requirements. However, Pepco has demonstrated that it is able to efficiently manage its capital spending program. As Company Witness Cantler testified, in 2022, actual capital spending for the year was

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188 PEPCO (3B): Leming Rebuttal at 21:5-17; 23:3-7.

189 *See, e.g.*, FC 1139, Order No. 18846 at ¶76; FC 1103, Order No. 17424 at ¶115. The Commission's generally excludes Construction Work in Progress ("CWIP") projects from rate base. FC 1053, Order No. 14712 at ¶68.

approximately $424.3 million against a budget of $436.5 million, a 2.8% variance to budget.[190] This was achieved despite high inflation[191] and global and domestic supply chain challenges.[192]

During the Hearing there was discussion of the Company's cost estimation and concern that a +/- 50% estimate was too broad. It must be noted that this estimation applies to the initial early stage, which is preliminary in nature. At this earliest preliminary phase a project's scope is still being defined and therefore the Company does not have detailed designs nor any firm contractor bids or executed contracts so the estimates are appropriately broad. As Company Witness Cantler explained, "[t]here are significant unknowns when a project is initially scoped and budgeted multiple years before execution."[193] However, as a project progresses through the project authorization process toward eventual project execution, project estimates become more and more acute, ultimately reaching a +/-10% margin during the project implementation phase.[194] The process Pepco follows to develop and refine project designs and budgets is consistent with best practices across Exelon.

In addition to complying with applicable Commission directives, the Construction Report also supports the MYP. Company Witness Cantler described Pepco's comprehensive capital budget development and planning process and the enhancements the Company has made to it.[195] She also indicated that each distribution project is reviewed on a monthly basis and adjustments

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190 PEPCO (H): Cantler Direct at 28:12-15 & Table 1.

191 The U.S. Bureau of Labor Statistics reported that for 2022 the Consumer Price Index for All Urban Consumers showed 6.5% inflation. PEPCO (G): Vahos Direct at 9 n.11.

192 PEPCO (H): Cantler Direct at 29:14-30:4. Company Witness Cantler discussed the strategies the Company has implemented to mitigate supply chain issues including semi-conductor shortages, manufacturing disruptions, significant supply demand increases, logistic issues, and global commodity instability and wars. *Id*. at 30:6-31.2.

193 PEPCO (H): Cantler Direct at 29:8-9.

194 PEPCO (4H): Cantler Rebuttal at 12:12-17.

195 *See generally* PEPCO (H): Cantler Direct at III.

may be made to current-year budgets to account for things like normal construction lifecycle activity or emergent need.[196] As a result, project deferrals may be filled with accelerated prioritized projects and, as system conditions change, projects may be added, modified, or deferred.[197] Additionally, risks such as unanticipated load growth, significant weather events, unforeseen field conditions, permitting, resource and material availability, supply chain challenges, outage availability, inflation, lingering issues from the COVID-19 global pandemic, and new legislation or regulation may also impact the Company's capital spending plans and project completion.[198] Additionally, because many of Pepco's capital projects are complex and span multiple years, as a project advances through the design engineering and construction processes, changes in budgets will naturally occur.[199] Because project planning and execution is by nature a dynamic process involving many variables, over the course of the MYP, some projects ultimately may not follow the scheduled "start" and "finish" times in PEPCO (H)-2.

The projects that are projected to close to rate base and are reflected in the MYP's rates are, generally speaking, projects that are further along as they have to be completed prior to December 31, 2026. Such projects, even those with long lead times, however, are no longer in the initial preliminary study phase. Rather, their budgets have been refined through the design and budgeting process as detailed in the testimony of Company Witness Cantler and have reached the project implementation phase. The budgets for such projects would at that stage have a +/- margin

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196 PEPCO (H): Cantler Direct at 25:14-26:2.

197 PEPCO (H): Cantler Direct at 26:3-10. To fund new projects identified during the current year, such as for emergent work or new business connections not previously identified, the Company will look to support the project need from an existing funding source within the capital portfolio. This may require the re-prioritization of capital projects projections to remain within approved LRP capital budget. *Id*. at 27:12-18.

198 PEPCO (H): Cantler Direct at 28:18-29:7. Company Witness Cantler discussed actions the Company is taking and strategies that have been implemented to mitigate and address supply chain issues. *Id*. at 30:6-31:2.

199 PEPCO (H): Cantler Direct at 29:7-11.

of 10% (or less depending on when the project was implemented and when it is projected to be completed).

Variances in Pepco's actual versus its projected spending plan for a particular year should not cast doubt on the Company's forecasting for capital investments. As discussed above, there are many factors that can impact the timeline for capital expenditures on a project, many of which are not within the Company's control. However, as discussed above, the mere fact that variances occur does not demonstrate that Pepco's capital costs on a project are unreasonable or imprudent. The fact that there may be variations from plan in a project's capital spending in any given year does not necessarily mean that the final cost of the project when it is completed and placed in service is outside of budget. In any event, the reconciliation mechanism will return to customers any over earning due to over-spending.[200]

E. The Bill Stabilization Adjustment Remains Appropriate in the Context of an MYP and Should Be Continued.

The BSA is a revenue decoupling mechanism that the Commission implemented in 2009 in FC 1053 to "account for changes in usage due to variations in weather, customer response to price increases or energy-efficiency programs."[201] As the Commission explained:

> Decoupling is a regulatory tool designed to separate a utility's revenue from changes in energy sales. Under traditional regulation, a utility's profitability is dependent on its sales volume. Decoupling has been offered as a solution to further public policy goals of encouraging the development of energy efficiency or to make a utility indifferent with respect to encouraging reduced energy consumption initiatives.[202]

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[200] FC 1156, Order No. 20755 at ¶474 ("Further, the reconciliation process we adopt ensures that any over earning by Pepco due to an over-spending is refunded to customers").
[201] FC 1053, Order No. 15556 at ¶2.
[202] FC 1053, Order No. 15556 at ¶24.

Additionally, the BSA is necessary to protect customers from fluctuations in their bills during increased energy usage due to extreme weather, which is an important consideration given the impacts from climate change. The Commission's Auditor's report also noted that insulating customers from the volatility that can be caused by extreme weather was one of the reasons the Commission implemented the BSA and indicated:

> The ability of the BSA to insulate customers from volatility caused by extreme weather is undisputed. The mechanism is based on weather normalized billing determinants and regardless of the actual weather, customers' bills will always reflect normal weather.[203]

In FC 1156, the Commission rejected arguments from some parties that the BSA should be terminated. In addition to determining that the BSA "provides adequate incentive for Pepco to develop energy efficiency programs to achieve GHG reduction and clean energy goals to address the District climate plans,"[204] the Commission noted that other jurisdictions had not eliminated similar decoupling mechanisms when they implemented an MYP.[205] The Commission indicated that the BSA would be continued, explaining that "decoupling remains a valuable incentive for the utility to implement energy efficiency and demand response programs encouraged by the [Clean Energy Act]."[206]

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203 BSA Audit Report at 25.

204 FC 1156, Order No. 20755 at ¶313.

205 FC 1156, Order No. 20755 at ¶315. The Commission also found that the BSA "continues to be a credit-positive feature for the company and helps maintain its Investment grade credit rating." *Id.*

206 *Id*. Similarly, in FC 1139, the Commission held that "the BSA serves an important function and should be retained." FC 1139, Order No. 18846 at ¶306. There the Commission noted that the introduction of more energy efficiency programs and measures, and the growing adoption of DER, such as rooftop solar and combined heat and power, would produce declining sales per customer. *Id.*

Although it continued the BSA in FC 1156, the Commission indicated that it believed the BSA could be further improved and therefore directed that a technical conference be held.[207] Additionally, the Commission directed that an audit of the BSA be performed[208] and selected Atrium Economics, LLC ("Atrium") to perform it.[209] The audit included an evaluation of the processes, procedures, mechanics, and internal controls surrounding the BSA.[210] In its final audit report ("BSA Audit Report") dated July 7, 2023, Atrium found that "the BSA is well designed, such that the structure, processes, and procedures of the BSA mechanism are sufficient to achieve the objectives prescribed by the DC Commission and are aligned with best industry practices."[211]

Despite the foregoing, AOBA and OPC continue to ignore the findings of the Commission's independent auditor by advocating that the BSA be discontinued.[212] AOBA Witness B. Oliver asserts that the BSA is not necessary in the context of an MYP in which rates are set based on forecasted costs and billing determinants and there are annual reconciliation filings.[213] This argument, however, is undermined by the finding in the BSA Audit Report that

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207 FC 1156, Order No. 20755 at ¶316. Technical conferences were convened by Staff on November 19, 2021, December 9, 2021 and January 20, 2022. FC 1156, Order No. 21168 at ¶2. One of the topics of discussion at the technical conferences that were subsequently held was the BSA deferral balances attributable to the COVID-19 pandemic. A proposal to move a portion of the current BSA deferral balance is discussed further below in Section G below. The enhancements to the BSA the Company is proposing as part of the MYP were developed from discussions at the BSA technical conferences.

208 FC 1156, Order No. 20755 at ¶425; FC 1156, Order No. 21042 at ¶129.

209 FC 1156, Order No. 21531.

210 BSA Audit Report at iii.

211 BSA Audit Report at iv. *See also id*. at 28-29. Atrium did suggest a number of enhancements that could be made to the BSA. Several of the BSA enhancements Pepco has proposed as part of the MYP are consistent with Atrium's suggestions. Pepco's proposed enhancements to the BSA are discussed in Section H below.

212 AOBA (A): B. Oliver Direct at 67:3-5; OPC (A): Dismukes Direct at 10:15-20; 107:1-10. Both also suggest modifications to the BSA if it is continued. These are discussed in Section H below.

213 AOBA (A): B. Oliver Direct at 67:15-68:15. He also argues that the BSA has not achieved its intended objectives of stabilizing the charges billed to customers or reducing the frequency of Pepco's base rate case filings.

most decoupling mechanisms they studied were within multi-year rate plans. The BSA Audit Report indicated:

> Through our review of best practices, Atrium finds that Pepco's BSA is similar in design to full decoupling mechanisms in other state jurisdictions within adjacent regions. We note that nearly all of the utility decoupling mechanisms we researched were operating under a multi-year rate plan.[214]

OPC Witness Dismukes erroneously characterizes the BSA as an earnings attrition mechanism and argues that it reduces incentives for the Company to prudently manage or closely monitor its billing practices. He claims that the BSA is not functioning as intended and that it insulates the Company from a wide range of business risks, including the economic contraction caused by COVID-19.[215] OPC Witness Dismukes recommends discontinuance of the BSA.[216]

The BSA should be continued because it provides a fully symmetric mechanism that removes the link between electricity usage and Pepco's distribution revenue.[217] It aligns with the District's public policy and climate goals because it allows the Company to support programs that result in decreased customer electricity usage such as Solar for All, DER, community solar, energy efficiency, and innovative rate designs (e.g., net energy metering, time-of-use rates) without incurring financial harm.[218] As the BSA Audit Report noted, the BSA continues to serve an important function even when energy efficiency is effectuated by 3rd party administrators, such as the DC SEU, as it remains important for the utility to be indifferent to impact on overall usage.[219]

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214 BSA Audit Report at ix.

215 OPC (A): Dismukes Direct at 87:21-88:11.

216 Id. at 10:15-20.

217 Company Witness Bonikowski indicated that decarbonization efforts will produce increased electrification which will counter the decline in sales due to energy efficiency and DER. This will create the potential for benefits to customers that may otherwise be lost in the absence of decoupling. PEPCO (3E): Bonikowski Rebuttal at 7:17-21.

218 PEPCO (3E): Bonikowski Rebuttal at 3:6-4:3, 7:6-16. In the absence of decoupling, the Company has a disincentive to encourage customers to conserve energy as this lowers distribution revenue. *Id*. at 7:1-4.

219 BSA Audit Report at 27.

The BSA Audit Report indicated that the DC SEU has been increasingly producing energy efficiency savings since 2013 and estimated that the cumulative savings from its energy efficiency programs would be approximately 1,400,000 MWh by 2026.[220] It concluded that these significant energy savings were "due in no small part to the elimination of the throughput incentive for Pepco and its general alignment with the goal of achieving substantial energy consumption reductions. Atrium finds that full decoupling has been an important tool and contributor to the success of DC SEU."[221]

Moreover, contrary to AOBA's claims, the fact that the MYP uses forecasted billing determinants that account for forecasted changes in usage due to factors such as energy efficiency and transportation electrification, does not remove the need for the BSA. Forecasting is by its nature not perfect and it is unable to capture the impact of emergent programs that could start during the MYP that would result in usage changes.[222] The BSA also removes the disincentive Pepco would otherwise have to promote initiatives past the point where they would reduce usage to a level below the baseline included in the Company's forecast.[223]

Similarly, contrary to AOBA's suggestion, the MYP's reconciliation process does not obviate the need for the BSA. As Company Witness Bonikowski explains, these are separate mechanisms that are designed to achieve different objectives. The BSA is focused on factors beyond the Company's control, such as weather, along with programs offered by the Company, that create either over- or under-collection of revenues from customers. The annual reconciliation

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220 BSA Audit Report at Figure 2.8.
221 BSA Audit Report at 28.
222 PEPCO (3E): Bonikowski Rebuttal at 8:7-9:2.
223 PEPCO (3E): Bonikowski Rebuttal at 8:11-15.

process is generally focused on the Company's spending, relative to a Commission approved revenue requirement, and the structure of the reconciliation mechanism reflects that focus on Company spending.[224] The Maryland Commission recently indicated that a BSA should continue to be used in conjunction with an MYP, explaining that "the BSA and the MYP Adjustment are separate mechanisms with different goals."[225]

OPC's assertions that the BSA reduces Pepco's incentives to closely monitor its billing practices are incorrect. Pepco maintains a robust suite of controls to ensure that its Commission-approved BSA targets and rates are appropriately developed and billed to customers, and has swiftly moved to correct any errors and institute new controls to prevent recurrence.[226] Finally,

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224 PEPCO (3E): Bonikowski Rebuttal at 9:5-12.

225 Maryland Commission Case No. 9702, Order No. 91181 at 189. Additionally, as Company Witness Bonikowski indicated, the Maryland PSC has found that a revenue decoupling mechanism remains appropriate in the context of MYPs with annual reconciliation mechanisms. See PEPCO (3E): Bonikowski Rebuttal at 12:4-31. For example, in Order No. 90445 in the Delmarva Power and Light Company MYP, the Maryland Commission held:

> Regarding the BSA, the central dispute between the parties is whether the BSA is still useful in a forecasted ratemaking environment. As the Commission identified in its concerns in Order No. 89868, a principal function of the BSA has been to disconnect utility revenues from individual consumer behavior, most notably behavior caused by weather variation and public policy initiatives to reduce energy usage and improve energy efficiency.
>
> At the same time, the Commission notes that, under historic ratemaking, the BSA has normalized weather variability and corrected under-recovery driven by Commission programs supporting major state priorities such as energy efficiency and renewable resource adoption. The Commission also notes the arguments of Staff and DPL that forecasts are not perfect. As such, removing the BSA would create undesirable utility incentives, even under a forecasted ratemaking paradigm. The Commission also notes the arguments of DPL and Staff that removing the BSA would make future cost of service studies more volatile, thereby compromising the Commission's objective of setting cost-based rates.
>
> In the present case, however, the Commission finds that DPL has adequately responded to the Commission's directive in Case No. 89868, and that the use of the BSA in forecasted rate cases should be allowed to continue. The Commission is satisfied that the BSA serves important roles in reducing weather related revenue fluctuations, removing disincentives to pursue current state policy goals, reducing volatility in ratemaking, and providing customer protections when utilities over collect.

See Maryland Commission Case No. 9681, Order No. 90445 at ¶¶67,69 & 72.

226 PEPCO (3E): Bonikowski Rebuttal at 10:8-12.

the BSA audit following FC 1156 included a comprehensive evaluation of the BSA's operations and Pepco's quality control procedures.[227] The BSA Audit Report found that:

> Pepco has a robust system of internal controls and is supported by a highly skilled internal audit group, Exelon Audit Services Advisory. During the review of Pepco's BSA processes, it was apparent that Pepco has improved internal control processes throughout the audit period in question. Atrium finds that Pepco's internal controls are reasonable and appropriate to lessen the potential for errors in inputs to the BSA calculation.[228]

Continuation of the BSA as part of the MYP ensures that each customer class pays no more or less than the revenue requirement ultimately approved by the Commission and assigned to each rate class.[229] OPC's and AOBA's suggestions to terminate the BSA are misguided and should be rejected.[230] The BSA continues to serve an important function especially given the policy objectives of the Clean Energy Act and should continue as part of the MYP approved in this proceeding.

F. Retroactive Disallowance of Certain BSA Deferral Balances Is Unwarranted and Would Be Contrary to Established Precedent.

Several parties made suggestions regarding the treatment of BSA deferral balances that relate to the impact of: 1) the GT LV Normalization Adjustment under the Non-Unanimous Full Settlement Agreement and Stipulation in FC 1150 ("FC 1150 Settlement"); and 2) the demand billing determinant error in FC 1150. These are addressed in turn below.[231]

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227 FC 1156, Order No. 21531 at ¶2.
228 FC 1156, BSA Audit Report at 72, F-3.2(3).
229 PEPCO (3E): Bonikowski Rebuttal at 11:21-24.
230 The parties' suggestions regarding the treatment of BSA deferral balances are discussed in Section F below.
231 The Company also addresses a new proposal AOBA made in its response to Pepco DR 1-20.

1. Any small remaining BSA deferral balances that resulted from the GT LV Normalization Adjustment in the FC 1150 Settlement are recoverable.

Under the FC 1150 Settlement,[232] Schedule GT LV rates were designed using forecasted customer counts rather than actual customer counts so as to reflect anticipated customer growth resulting from Pepco's annual customer rate migration process in the design of rates and BSA targets.[233] However, fewer customers migrated into the GT LV rate class than expected, resulting in a projected revenue shortfall.[234] To address this result, it was agreed that the Schedule GT LV BSA targets were to be calculated based on the lower number of actual customer counts rather than the forecasts used to design rates.[235] As the BSA Audit explained:

> The GTLV normalization adjustment was a negotiated settlement with the Commission and intervenors to acknowledge that the customer forecast in rates was too high. It was clear that the Company would not collect its revenue requirement through billed revenues or through its BSA targets. As part of the settlement agreement, the settling parties agreed to increase the per customer revenue target but made no adjustment to rates (which were premised on the higher customer count). As such, the GTLV normalization adjustment settlement would allow Pepco to recover a greater share of revenue under its BSA than through rates.[236]

Under-recoveries associated with the FC 1150 Normalization Adjustment ended when the rates established in FC 1156 became effective on July 1, 2021. The BSA Audit Report indicated that the FC 1150 Normalization Adjustment resulted in $27.1 million in revenue under-recoveries.[237]

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232 AOBA and OPC were both signatories to the FC1150 Settlement. The Commission approved the FC1150 Settlement pursuant to Order No. 19433,

233 PEPCO (3E): Bonikowski Rebuttal at 21:17-21.

234 PEPCO (3E): Bonikowski Rebuttal at 21:21-22.

235 PEPCO (3E): Bonikowski Rebuttal at 22:1-3. See FC 1150 & 1151, *Motion to Clarify* (June 27, 2018). *See also* FC 1150 & 1151, Order No. 19433 at ¶51 (Commission grants the Motion to Clarify and accepts "the Settling Parties' proposal to use the actual number of customers to calculate the GT-LV per customer revenue for use in Potomac Electric Power Company's Bill Stabilization Adjustment updates.")

236 BSA Audit Report at 48.

237 BSA Audit Report at Table 2-9.

OPC mischaracterizes the FC 1150 Normalization Adjustment as being a Pepco administrative error and inappropriately claims that Pepco should be held financially liable for revenue under-recoveries that resulted from this adjustment.[238] The Commission should reject OPC's proposal, which effectively functions as a penalty, as the FC 1150 Normalization Adjustment was **not** the result of an administrative error but rather was part of the settlement negotiated in FC 1150 and approved by the Commission in Order No. 19433.

As Company Witness Bonikowski explained, the Motion for Clarification of the FC 1150 Settlement clearly addressed this matter.[239] Moreover, footnote 167 in Order No. 19433 approving the FC 1150 Settlement references Pepco's Responses to Staff Data Request No. 3-5 and 8-3, each of which is clear that the parties to the FC 1150 Settlement agreed to design GT LV rates using projections for customer counts, billed demand, and sales.[240] Similarly, the BSA Audit Report indicated that the FC 1150 Normalization Adjustment "was a negotiated settlement with the Commission and intervenors to acknowledge that the customer forecast in rates was too high."[241]

There is no basis for OPC's proposal that penalizes the Company by reducing the BSA deferral balances by $27.1 million on account of the FC 1150 Normalization Adjustment. These amounts were the result of the terms of the FC 1150 Settlement and were appropriately reflected in the BSA deferral balances in accordance with the workings of the Commission-approved BSA

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238 OPC (A): Dismukes Direct at 100:11-17; 110:17-23; OPC (A)-19.
239 PEPCO (3E): Bonikowski Rebuttal at 22:11-28 (quoting FC 1150 Motion to Clarify at ¶¶2,5,8.)
240 PEPCO (3E): Bonikowski Rebuttal at 22:30-23:4; PEPCO (3E)-17.
241 BSA Audit Report at 48, F-2.3(2).

tariff.[242] There is no reasonable basis to alter the agreed upon terms of the FC 1150 Settlement and now retroactively deny recovery of these balances.

Additionally, in accordance with the Commission's directives in approving the BSA, the Company has submitted a monthly BSA filing that includes the BSA calculation that shows the deferral balance for each customer class. In Order No. 15556, the Commission indicated that these "monthly BSA filings shall be deemed approved and shall become effective for the next month in the absence of a Commission Order directing otherwise."[243] Pepco has complied with the Commission's directives regarding the submission of monthly BSA filings and the Commission has not issued any orders blocking or deferring the effectiveness of Pepco's monthly BSA filings.

Moreover, such a retroactive adjustment would be contrary to well-established precedent. The Commission has held that the BSA is, itself, a rate.[244] No party has claimed that Pepco miscalculated the deferral balances under the Commission-approved BSA formula. The BSA deferral balances are not the result of an error in the BSA mechanism. The BSA has performed as it was intended and as the Commission authorized. As the BSA Audit Report indicated, "[e]rrors in billing determinants are not analogous to errors in the BSA mechanism or the BSA targets which the company is authorized to recover."[245]

Under well-settled precedent, the Commission is not allowed to retroactively adjust rates. For example, in *District of Columbia v. Pub. Serv Comm'n*, 905 A.2d 249 (D.C. 2006) (*DC v. PSC*"), the District of Columbia Court of Appeals rejected the District's appeal retroactively to set

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242 As discussed further below, OPC's suggestion to retroactively alter the operation of the Commission-approved BSA tariff is inappropriate and would be contrary to well-established precedent.

243 Order No. 15556 at Attachment A ¶8.

244 FC 1053, Phase II, Order No. 15042 at ¶¶1, 19.

245 BSA Audit Report at iv.

aside the Commission's determination to classify Verizon DC's E-911 service as a competitive service in the 2002 Price Cap Plan. Following its approval of the 2002 Price Cap Plan, the Commission in a subsequent proceeding had reclassified E911 service back to being a basic service and invited Verizon to propose a lower, reasonable rate to replace the E911 rate that had been in effect. However, the Commission refused to relieve the District of its obligation to pay Verizon the full tariff rate for the period when the earlier tariff was in force. The Commission explained "[w]e cannot use our subsequent determination that the E911 service should be reclassified as a basis for rendering the filed rate illegal because to do so would violate the well-settled prohibition against retroactive ratemaking."[246] On reconsideration, the Commission reiterated:

> The filed rate doctrine and its corollary, **the rule against retroactive rate making, bars this Commission from retroactively substituting what we perceive as an unreasonably high or low rate with one that we perceive is just and reasonable**. The filed rate doctrine forbids a regulated entity to charge rates for its services other than those properly filed with the appropriate regulatory authority. The related rule against retroactive rate making prohibits the regulatory authority from adjusting current rates to make up a utility's overcharge or undercollection in prior periods.[247]

On appeal from the Commission's decision, the Court of Appeals rejected the District government's appeal requesting retroactive rate relief, finding that its argument was foreclosed by the filed rate doctrine and its corollary, the prohibition against retroactive alteration of established rates. The Court noted the US Supreme Court's decision in *Arizona Grocery Co. v. Atchison, Topeka & Santa Fe Ry. Co.*, 284 U.S. 370 (1932), that held "once a regulatory body has authorized a public utility to charge a particular rate, having found that rate to be reasonable, it may not require

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246 FC 1005, Order No. 13149 at 10.
247 FC 1005, Order No. 13258 at 6–7 (July 30, 2004)(emphasis added)(footnotes and citations omitted).

the utility to pay refunds to its customers based on its subsequent finding that the rate was excessive -- even if it concludes that it made an error when it approved the rate in the first place."[248]

Similarly, in Phase I of FC 1053, OPC argued that the Commission in FC 939 disallowed all costs associated with the Company's Supplemental Executive Retirement Plan ("SERP"), but Pepco had only excluded the expense portion and not the capitalized portion. OPC claimed all SERP costs capitalized since FC 939 should therefore be excluded. In Order No. 14712, although the Commission removed the entire amount of SERP from rate base, not merely the expense portion, and indicated that its "reasoning in Order No. 10646 [in FC 939] clearly applies to all SERP costs," the Commission rejected OPC's suggestion to exclude the capitalized portion of the SERP costs Pepco had incurred since FC 939 as "this would amount to retroactive ratemaking."[249] The Commission's decision on this issue was ultimately upheld by the District of Columbia Court of Appeals.[250] The Court indicated that the Commission in Order No. 14712 had:

> refused to order a further reduction reflecting the aggregate capitalized SERP costs that Pepco had carried on its books since the decision in FC 939, because while that decision had disallowed "all" SERP costs, capitalized costs had not been an issue before it in that proceeding or a subject of its ruling, and so Pepco could have properly continued to include them in its rate base during the interim period. Moreover, Pepco had included these costs in its "compliance filing[s]" for those years without objection by any party. In these circumstances, the PSC concluded that disallowing the past capitalized SERP costs now would amount to retroactive ratemaking, which is prohibited by "the ... filed rate doctrine and its corollary, the prohibition against retroactive alteration of established rates."[251]

The Court of Appeals rejected OPC's arguments that the Commission had erred. It noted:

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[248] 905 A.2d at 257. The Court noted two exceptions: (i) if the rates were procured by fraud and (ii) if the parties are placed on notice from the outset that the rate is not final but subject to adjustment. Neither of these exceptions are applicable in the case of the BSA.

[249] FC 1053, Order No. 14712 at ¶190.

[250] *Off. of People's Couns. v. D.C. Pub. Serv. Comm'n*, 989 A.2d 190, 193 (D.C. 2010).

[251] *Id*. at 193 (quoting DC v. PSC).

> it is clear from its briefs that the OPC seeks the "remov[al]" from Pepco's rate base of the capitalized SERP costs "that [Pepco] has improperly accumulated on its books since the Commission's Order in [FC 939] was issued"; in other words, the OPC argues that the "profits" that Pepco gained through including in its rate base certain costs that the PSC had "disallowed" in 1995 should be returned to the ratepayers by a corresponding reduction in the rate base "going forward." . . . We find no error in the Commission's application of principles concerning retroactivity, or its refusal to order recoupment of costs that Pepco had included in its base before the present 2008 order.[252]

Because the BSA formula is a rate that expressly provides for the creation of deferral balances as a result of the operation of the 10% cap, as well as the dollar-for-dollar recovery of the deferral balances in subsequent months, it cannot be retroactively changed.

Finally, this issue will essentially be moot by the time an order in this proceeding is issued. As the BSA Audit Report noted, through the operation of the BSA, by December 31, 2022, approximately $7 million of the under-recovery attributable to the FC 1150 Normalization Adjustment remained in the BSA deferral balances.[253] Using the same approach described in the BSA Audit Report, Pepco estimated that, as of December 2023, approximately $3.4 million remained uncollected.[254] This amount has further declined over 2024.

2. *Any small remaining BSA deferral balances from the demand billing determinant error identified and corrected in FC 1156 are appropriately recoverable through the operation of the BSA Tariff.*

OPC Witness Dismukes also argues that the BSA deferral balances associated with the demand billing determinant error the Company identified and corrected in FC 1156 should be disallowed.[255] OPC's suggestion should be rejected as it constitutes a retroactive attempt to

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252 *Id*. at 194.
253 *See* BSA Audit Report at F-2.3(6) & Table 2:16.
254 *See* PEPCO (3E): Bonikowski Rebuttal at Table 3; PEPCO (3E)-15.
255 OPC (A): Dismukes Direct at 100:5-11; 110:17-23; OPC (A)-19.

modify the operation of a Commission-approved tariff. Moreover, these deferral balances arose because the billing determinants used to set rates established in FC 1150 were overstated and thus Pepco collected **less** in rates than the Commission actually authorized. Finally, as the BSA Audit Report indicated, if there is any remaining under-recovery attributable to the demand billing determinant error, it is *de minimus* at this point.[256]

In FC 1156, Pepco determined that a double counting issue in months with a time slice[257] had resulted in overstated demand billing determinants. Although this was corrected in FC 1156, the demand rates established in FC 1150 were lower than if they had been based on actual demand.[258] This resulted in an under recovery of billed distribution revenues through base distribution rates.[259] In Order No. 20755, the Commission found that the demand billing determinant error only affected the demand charge component of bills for commercial customers with demand rates.[260] The BSA Audit Report estimated that $15.1 million in revenue under-recoveries related to the FC 1150 billing determinant error.[261]

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256 See FC 1156, BSA Audit Report at 51-52.

257 A "time slice" occurs when there are multiple price values within a bill period (such as a month within which a rate change occurs), and that price is set up to be prorated within that period. FC 1156, PEPCO (7F): Blazunas Fourth Supp. at 4. Company Witness Blazunas explained "for an individual customer when the report is pulling it, if there's a time slice, it is double counting it for that individual customer;" however, because customers are not all billed on a single day of the month but rather throughout a month, there was not necessarily a double counting for the entire class within one month as a result of the time slice issue with the variant report, particularly when the change in Commission-approved rates becomes effective in the middle of month, as was the case in FC 1150/1151. FC 1156, Hearing Transcript at 175-176.

258 In FC 1150, the billing determinants used to establish most rates were for the 12 months ended September 30, 2017, a period that included the change in rates the Commission approved in FC 1139 as those rates became effective on August 15, 2017, and thus had the time slice issue.

259 Following Pepco's identification and correction of the billing determinant error in FC 1156, the Company also implemented a range of corrective actions to mitigate the risk of any similar error occurring in the future. *See* FC 1156, PEPCO (7F): Blazunas Fourth Supp. at 10-12. Following a comprehensive evaluation of the BSA operations and Pepco's quality control procedures, the BSA Audit Report found that Pepco had a robust system of internal controls and concluded that the Company's "internal controls are reasonable and appropriate to lessen the potential for errors in inputs to the BSA calculation." BSA Audit Report at 72.

260 FC 1156, Order No. 20755 at ¶421.

261 BSA Audit Report at 37 (F-2.2(2) and Table 2-7).

OPC suggests that the full \$15.1 million be removed from the BSA deferral balance. However, this significantly overstates the amount attributable to the FC 1150 billing determinant error that remains in the BSA deferral balances. The BSA Audit Report indicated that, through the operation of the BSA, by December 31, 2022, approximately \$2 million of the under-recovery from this driver remained in the BSA deferral balances.[262] Using the same approach described in the BSA Audit Report, Pepco estimated that, as of December 2023, approximately \$1.1 million of the revenue under-recoveries identified in the BSA Audit Report remained uncollected.[263] This amount has further declined over 2024.

As Company Witness Bonikowski explained, the demand billing determinant error that Pepco identified and corrected in FC 1156 did not affect the revenue requirement approved by the Commission, nor the calculation of the BSA revenue per customer targets in FC 1150.[264] The error resulted in demand-metered commercial customers paying artificially low rates as a result of FC 1150. Customers, in effect, deferred paying a portion of the revenue requirement approved by the Commission in FC 1150, and the BSA has functioned to reconcile revenues for each rate class to the level of Commission authorized revenue.[265] However, this does not render recovery of these amounts imprudent or improper.[266]

Finally, OPC's suggestion would retroactively alter the BSA tariff and is therefore inappropriate. In FC 1156, the Commission did not eliminate the BSA. To the contrary, the

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262 *See* BSA Audit Report at F-2.3(6) & Table 2:16.
263 *See* PEPCO (3E): Bonikowski Rebuttal at Table 3; PEPCO (3E)-15.
264 PEPCO (3E): Bonikowski Rebuttal at 20:6-8.
265 PEPCO (3E): Bonikowski Rebuttal at 20:8-13.
266 PEPCO (3E): Bonikowski Rebuttal at 20:3-15. Moreover, under the current BSA tariff, Pepco does not earn a return on the BSA deferral balances.

Commission held that it would "not terminate the BSA because decoupling remains a valuable incentive for the utility to implement energy efficiency and demand response programs."[267] Nor, despite the arguments of some parties, did the Commission in FC 1156 disallow any BSA deferral balances, indicate that the balances were subject to adjustment, or alter the manner in which the deferral balances are collected through the BSA. To be clear, the deferral balances are not the result of an error in the BSA.[268] The BSA has performed as it was intended and as the Commission authorized. Because the BSA is a Commission-approved tariff and rate, as discussed above, under well-settled precedent, it cannot be retroactively adjusted to eliminate a balance that has already appropriately been accrued.[269] It would be inconsistent with Commission precedent to deny recovery of any remaining deferral balance that is due to the billing determinant error identified and corrected in FC 1156.

3. *AOBA's suggestion to limit recovery of GT LV revenue under-recoveries through the BSA should be rejected.*

Although not raised in Direct Testimony, in AOBA's Response to Pepco Data Request No. 1-20,[270] AOBA recommended that Schedule GT LV revenue under-recoveries should only be recovered to the extent that billed revenues in each month were less than the billed revenue forecasts provided in Pepco's June 24, 2021 and January 11, 2023 compliance filings in FC 1156. AOBA claims that all other Schedule GT LV revenue under-collections between July 2021 and December 2023 reflect non-cost-based increases in authorized revenues resulting from the use of

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267 Order No. 20755 at ¶315.

268 Atrium indicated "Errors in billing determinants are not analogous to errors in the BSA mechanism or the BSA targets which the company is authorized to recover." BSA Audit Report at iv.

269 *See, e.g., District of Columbia v. Pub. Serv Comm'n*, 905 A.2d 249 (D.C. 2006).

270 PEPCO (3E)-16 at page 3.

inappropriately low estimates of GT LV customer counts. As a result, AOBA submits that the GT LV BSA deferred revenue balance should be reduced to not greater than $12,902,123.[271] AOBA further argues that Pepco should be "held responsible for a significant portion of the remaining [BSA revenue deferral] balance due to its admitted errors."[272]

Although the actual number of GT LV customers has been higher than the forecast that underlies Pepco's rates since the Company's first MYP, this does not render those billing determinants "inappropriate" as AOBA suggests. Pepco has used the billing determinants the Commission found reasonable and approved in FC 1156. Pepco is required to use the most current Commission-approved billing determinants forecasts.[273] When Pepco sought to update its billing determinants to become effective January 1, 2023, AOBA opposed that request and the Commission rejected Pepco's proposal and directed the Company to continue to use its existing approved billing determinants as AOBA had advocated.[274]

Moreover, AOBA's position is premised on the misconception that Pepco's authorized revenues under an MYP are fixed at the level of revenue prescribed in the Commission's Order. The Commission has consistently held that Pepco's authorized revenue for decoupled rate classes is determined by the class's approved revenue per customer targets multiplied by the number of customers in the class.[275] The Commission did not change this formulation in FC 1156. Thus, to the extent that customer counts increase or decrease as compared to the billing determinants

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271 AOBA Response to Pepco DR 1-20.
272 AOBA Response to Pepco DR 1-20.
273 Pepco has not proposed an annual billing determinant update in this proceeding; however, as articulated in the Company's comments on Atrium's Final BSA Audit Report, the Company continues to support an annual billing determinant update. PEPCO (3E): Bonikowski Rebuttal at 25, n. 46.
274 FC 1156, Order No. 21563 at ¶16.
275 *See, e.g.,* PEPBSAR-2016-01, Order No. 18138 at ¶2 (citing FC 1053, Order No. 15556 at ¶32).

approved in a base rate case, the Company's authorized revenue for each class will differ from the nominal dollar amount specified in the Commission's rate case order.[276] AOBA's suggestion to retroactively disallow revenues Pepco is authorized to collect under the Commission-approved BSA tariff structure implicates the principles against retroactive ratemaking and should be rejected.

G. The Commission Could Consider Recovery Outside of the BSA of $46.8 Million in the GT LV BSA Deferral Balance Related to Declining Customer Usage During the COVID-19 Pandemic.

Both OPC and AOBA suggest that a portion of the BSA deferral balance related to declining customer usage during the COVID-19 pandemic be recovered outside of the BSA and through a regulatory asset, with a return on any unamortized balance.[277] While Pepco agrees in principle with such an approach, as Company Witness Bonikowski testified, the amounts that other parties suggest should be transferred to a regulatory asset are not reasonable.[278] Witness Bonikowski explained that it would be reasonable to remove $46.8 million from the Schedule GT LV BSA deferral balance and recover that balance through a regulatory asset.[279]

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[276] PEPCO (3E): Bonikowski Rebuttal at 27:17-20. Company Witness Bonikowski noted that Pepco has proposed certain enhancements to the BSA's design under its proposed MYP, including changing the basis of the BSA's revenue target from revenue-per customer targets to flat revenue-per-class targets; however, if this change were to be approved, it would apply only **prospectively**, not retroactively. *Id.* at 28:7-10.

[277] AOBA (A): B. Oliver Direct at 134:14-19; OPC (A): Dismukes Direct at 111:1-5, 113. In Surrebuttal Testimony, OPC indicated that the regulatory asset should only be assessed to GT-LV customers. OPC (2A): Dismukes Surrebuttal at 22:7-15.

[278] PEPCO (3E): Bonikowski Rebuttal at 18:3-11; 33:15-18. OPC suggests that $69.5 million be transferred to recovery outside of the BSA. AOBA indicates that between March 2020 and the end of June 2021, in excess of $39.7 million in revenue under-recoveries for the GT-LV class "should be primarily attributed to governmental restrictions on business and personal activities during the pandemic and identified for recovery outside of the BSA mechanism." AOBA (A): B. Oliver Direct at 61:5-9. See also *id.* at 126:1-3 ("significant portion of Pepco's current BSA deferred revenue is appropriately identified as COVID-19-related and should be recovered outside of the Company's BSA mechanism.")

[279] PEPCO (3E): Bonikowski Rebuttal at 18:11-13.

For example, noting a finding in the BSA Audit Report that $69.5 million, or approximately 25% of revenue under-recoveries between 2016 and 2022, were related to declining energy and demand usage driven by the COVID-19 pandemic, OPC Witness Dismukes recommends that the Commission consider alternative recovery options for $69.5 million outside of the BSA, including recovery within the Company's proposed COVID-19 regulatory asset.[280] However, as Company Witness Bonikowski explains, use of such a balance would significantly overstate the portion of the remaining BSA deferral balance that is related to the impact of the COVID-19 pandemic.[281] A portion of these under-collections has already been reconciled through the monthly BSA surcharges determined in accordance with the Commission-approved BSA tariff.[282] Indeed, the BSA Audit Report indicated that approximately $41.2 million of the total $69.5 million of COVID-19 related under-collections remained uncollected in the Company's BSA deferral balance as of December 2022.[283] Moreover, that amount has continued to decline since. Using the method described in the BSA Audit Report, approximately $26.3 million of COVID-19 related under-collections remained uncollected in the BSA deferral balance as of December 2023, of which approximately $22.9 million, or 87%, is attributable to the GT LV class.[284]

OPC's proposal to recover $69.5 million of BSA deferral balances outside of the BSA mechanism also introduces practical challenges as this is not a "lump sum" but rather is comprised of discrete revenue under-collections attributable to each rate class.[285] OPC's proposal would

280 OPC (A): Dismukes Direct at 111:1-5, 113.
281 PEPCO (3E): Bonikowski Rebuttal at 29:4-5.
282 PEPCO (3E): Bonikowski Rebuttal at 29:8-9.
283 PEPCO (3E): Bonikowski Rebuttal at 29:8-12. *See* BSA Audit Report at 52, Table 2-16.
284 PEPCO (3E): Bonikowski Rebuttal at 29:13-20 & Table 3, Table 5; PEPCO (3E)-15.
285 PEPCO (3E): Bonikowski Rebuttal at 30:2-5.

result in negative deferral balances for all rate classes except GT LV and GT 3A, effectively undoing collections of COVID-related under-recoveries that have already occurred through BSA surcharges, and deferring reconciliation of those amounts into the future.[286] In its response to Pepco Data Request No. 1-30,[287] OPC stated that it does not recommend establishing negative deferral balances for classes that have current BSA deferral balances lower than the COVID-19 related under-recoveries.[288]

AOBA also proposes that a portion of the BSA deferral balance be recovered outside of the BSA mechanism; however, AOBA's proposal is limited to the deferral balance for the GT LV class. AOBA Witness B. Oliver indicates that between March 2020 and June 2021, Pepco under-recovered $39.7 million of revenue from the GT LV class and argues that these under-collections should be primarily attributed to the impacts of COVID-19 and recovered through the Company's COVID-19 regulatory asset over a ten year amortization period.[289]

Although AOBA's proposal is generally reasonable, Company Witness Bonikowski explains that AOBA's method to identify the portion of the BSA deferral balance related to lower usage during COVID-19 is also overly simplistic.[290] AOBA's approach of attributing all GT LV revenue under-recoveries between March 2020 and June 2021 to COVID-19 likely overstates the impacts of the pandemic during that time,[291] and conversely fails to identify any under-collections related to the pandemic after June 2021 despite extensions of customer disconnection moratoriums

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[286] PEPCO (3E): Bonikowski Rebuttal at 30:6-11 & Table 4.
[287] *See* PEPCO (3E)-16.
[288] PEPCO (3E): Bonikowski Rebuttal at 31:2-4.
[289] AOBA (A): B. Oliver Direct at 61:5-9, 134:14-19.
[290] PEPCO (3E): Bonikowski Rebuttal at 18:9-11.
[291] PEPCO (3E): Bonikowski Rebuttal at 33:2-3.

related to the pandemic into 2022 and the fact that the Federal government's national emergency declaration for COVID-19 continued until May 11, 2023.[292]

Using the method described in the BSA Audit Report to analyze the drivers of BSA deferral balances, Pepco's analysis shows that, if the Commission were to adopt the parties' suggestion, $46.8 million should be removed from the Schedule GT LV BSA deferral balance and recovered through a regulatory asset, with a return at the Company's Commission-approved rate.[293] Company Witness Bonikowski explained that Schedule GT LV remains the only rate class for which a substantial proportion of 2020-2022 under-collections remain in the BSA.[294] For non-GT LV customers, all revenue under-recoveries from 2020 and 2021 and over 92% of revenue under-recoveries related to declining energy usage between 2020 and 2022 have already been reconciled through BSA surcharges.[295] Pepco therefore recommends that any recovery of BSA deferral balances through the Company's COVID-19 regulatory asset be limited to the applicable portion of the uncollected GT LV deferral balance, i.e., $46.8 million.[296]

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[292] PEPCO (3E): Bonikowski Rebuttal at 33:4-7.

[293] PEPCO (3E): Bonikowski Rebuttal at 33:19-34-21; PEPCO (3E)-15. Approximately $26.3 million of revenue under-recoveries the BSA Audit Report identified as directly related to COVID-19 remain uncollected as of December 2023. *Id*. at 34:2-3. Additionally, an incremental $25.9 million is associated with other declines in energy usage and demand during the period in which the BSA Audit Report identified COVID-related impacts. *Id*. at 34:3-6. Of this total $52.1 million in under-collections, approximately $46.8 million is associated with the GT LV class. *Id*. at 34:6-7.

[294] PEPCO (3E): Bonikowski Rebuttal at 34:7-8.

[295] PEPCO (3E): Bonikowski Rebuttal at 34:9-13.

[296] PEPCO (3E): Bonikowski Rebuttal at 34:13-16. PEPCO (3E): Bonikowski Rebuttal at 34:13-16. Exhibit PEPCO (3B)-2 provides the rate base, operating income, and revenue requirement impacts associated with removing $46.8 million from the BSA deferral balance and recovering that balance through base distribution rates via a separate regulatory asset over a period of 10 years.

H. Pepco's Proposed Enhancements to The BSA Are Reasonable and Should Be Adopted as Part of the MYP.

As part of its MYP, Pepco proposed a several enhancements to the BSA structure and mechanics to better align the BSA with an MYP rate environment in which rates are based on forecast billing determinants, costs, and revenues, and improve intraclass equity and increase rate predictability and transparency for customers.[297] Specifically, Pepco proposed the following four enhancements to the BSA: 1) change the revenue basis of the BSA from revenue per customer targets to a flat revenue target per class as approved in an MYP;[298] 2) transition from a monthly reconciliation and surcharge to an annual reconciliation and surcharge;[299] 3) add a demand charge component to the BSA surcharge for demand-metered classes;[300] and 4) display the BSA surcharge as a separate line item on customer bills.[301] Each of these enhancements is discussed below.[302]

1. Pepco's proposed changes to the BSA revenue target structure are reasonable.

Pepco's current BSA revenue structure, in which BSA revenue targets are structured as a monthly revenue per customer amount, was developed in the context of traditional backward-looking rate cases in which historic costs and billing determinants were used to set rates and remains appropriate under traditional ratemaking.[303] However, under an MYP ratemaking structure, the Company's rates and revenue requirement are based on forecasted data for each rate

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297 PEPCO (E): Bonikowski Direct at 60:4-9. Some of Pepco's proposed enhancements to the BSA were also incorporated into the TTYCF; however, several of the proposed enhancements are not appropriate in the context of the TTYCF.
298 PEPCO (E): Bonikowski Direct at 61:13-63:4.
299 PEPCO (E): Bonikowski Direct at 63:7-65:4.
300 PEPCO (E): Bonikowski Direct at 65:6-66:10.
301 PEPCO (E): Bonikowski Direct at 66:13-18.
302 Company Witness Bonikowski discussed the transition between the current BSA structure and Pepco's proposed structure. PEPCO (E): Bonikowski Direct at 67:3-10.
303 PEPCO (E): Bonikowski Direct at 61:13-18.

year, and, unlike traditional ratemaking, any incremental distribution system investments needed to support projected customer growth are embedded in those forecasts. The distribution revenue requirement ultimately approved by the Commission in an MYP will therefore account for expected customer and cost of service growth. As a result, under an MYP, Pepco proposes to shift from a revenue per customer target structure to a flat annual revenue target per class based on the revenue requirement and revenue allocation approved by the Commission.[304]

OPC Witness Dismukes indicates that, if the BSA is continued, OPC supports Pepco's proposal to shift to a flat annual revenue target per class.[305] Similarly, AOBA Witness B. Oliver states that, if the BSA is continued, "reasonably established flat targets would appear to be a preferred alternative for demand-metered commercial rate classes."[306]

Pepco's proposal to convert the BSA revenue target structure from revenue per customer targets to flat revenue targets for each rate class is reasonable and should be adopted.

2. *Pepco's proposal to calculate the BSA surcharge annually will provide greater rate certainty to customers and reduce surcharge volatility.*

The BSA surcharge currently is calculated on a monthly basis.[307] While this minimizes delays in cash reconciliation, it also introduces volatility for customers as the surcharge rate changes every month.[308] This rate volatility may at times be exacerbated by the timing of when

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304 PEPCO (E): Bonikowski Direct at 61:14-21. Because this is not the case under traditional ratemaking, Pepco did not include this enhancement in the TTYCF. PEPCO (2E): Bonikowski Supp. Direct at 25:15-26:10. Under the Company's proposal, following RY3 of the MYP, the Company's approved revenue requirement would hold flat at RY3 levels until the Commission approves new distribution revenue requirements in a subsequent MYP. PEPCO (E): Bonikowski Direct at 63:2-4.

305 OPC (A): Dismukes Direct at 11:1-2; 108:6-13.

306 AOBA (A): B. Oliver Direct at 64:5-6.

307 PEPCO (E): Bonikowski Direct at 63:7.

308 PEPCO (E): Bonikowski Direct at 63:7-9.

bills are issued, particularly for small classes.[309] To provide greater rate certainty to customers and reduce surcharge volatility, Pepco proposes to modify the BSA surcharge from a monthly calculation to an annual calculation under the MYP construct.[310] Like the current monthly surcharges, the proposed annual surcharge would be subject to the 10% cap.[311]

Company Witness Bonikowski cautions that while changing to an annual surcharge structure provides greater rate predictability for customers, it also increases the risk of deferral balances accumulating over time.[312] To address this risk, the Company's proposal includes an automatic adjustment to the BSA surcharges in the event that deferral balances experience a sharp increase between annual filings.[313] Pepco would assess its BSA deferral balances on a monthly basis and perform a reconciliation assessment for each rate class. That reconciliation would compare projected year-end deferral balances, based on a comparison of monthly billed revenue against monthly forecast revenue based on the latest Commission-approved billing determinant forecast, against the maximum revenue that could be reconciled through the BSA surcharge in the following year, if billed at the 10% cap.[314] If the assessment demonstrates that the deferral balance for a given rate class cannot be fully reconciled by the end of the following year, Pepco will file a notice with the Commission and increase the surcharge to the 10% cap for that rate class until surcharge rates are reset as part of the Company's next annual BSA surcharge filing.[315]

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309 PEPCO (E): Bonikowski Direct at 63:9-10.
310 PEPCO (E): Bonikowski Direct at 63:15-17. Pepco did not include this enhancement in the TTYCF as an annual surcharge structure would increase regulatory lag by delaying reconciliations of any revenue under- or over-recoveries until the following year. PEPCO (2E): Bonikowski Supp. Direct at 26:15-27:3.
311 PEPCO (E): Bonikowski Direct at 64:1-2.
312 PEPCO (E): Bonikowski Direct at 64:3-10.
313 PEPCO (E): Bonikowski Direct at 64:11-13.
314 PEPCO (E): Bonikowski Direct at 64:13-18.
315 PEPCO (E): Bonikowski Direct at 64:18-65:2. Pepco's proposal would be applicable to both positive and negative BSA surcharges. *Id*. at 65 n.55.

OPC Witness Dismukes indicates that, if the BSA is continued, OPC supports Pepco's proposal to calculate the BSA surcharge annually.[316] AOBA Witness B. Oliver states that, if the BSA is continued and given Pepco's proposal to terminate revenue per customer targets, "the transition to annual revenue reconciliations and annual surcharge adjustments would appear preferable to the current monthly mechanism.[317]

The Company's proposal to calculate the BSA surcharge annually is reasonable and should be adopted.

3. Pepco's proposed change to the BSA surcharge structure to include a demand component will improve intraclass equity.

The current BSA surcharge used to reconcile monthly BSA deferral balances is structured as a dollar-per-kWh rate for all classes.[318] As a result, high load factor customers (i.e., those with high energy usage and comparatively low demand) experience a higher bill impact on a percentage basis than low load factor customers.[319] Allocating the adjustment to both energy and demand charge for demand-metered classes maintains the existing relationship between these charges, and slightly reduces bill impacts on high load factor customers who efficiently use the distribution system, improving intraclass equity.[320] Therefore, for demand-metered classes subject to the BSA,

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316 OPC (A): Dismukes Direct at 11:1-2; 108:6-13.

317 AOBA (A): B. Oliver Direct at 64:18-21. AOBA Witness B. Oliver did suggest the Company's proposed schedule does not provide sufficient opportunity for review and input by other parties. *Id*. at 65:2-10.

318 PEPCO (E): Bonikowski Direct at 65:6-7.

319 PEPCO (E): Bonikowski Direct at 65:14-16.

320 PEPCO (E): Bonikowski Direct at 65:17-20.

Pepco proposes to modify the surcharge structure to include a demand component, consistent with the class's base distribution rate structure.[321]

OPC Witness Dismukes indicates that, if the BSA is continued, OPC supports Pepco's proposal to include a demand charge component to the BSA for applicable rate classes.[322] AOBA Witness B. Oliver states that "it is not clear that the added complexity will significantly improve the operation of Pepco's BSA mechanism,"[323] and he therefore suggests that the introduction of "a demand charge component to Pepco's BSA should probably be undertaken on an experimental basis if it is pursued."[324]

Pepco's proposal to modify the BSA surcharge to include a demand component is reasonable and should be adopted.

4. Pepco's proposal for the presentation of BSA surcharges on customer bills will enhance bill transparency.

BSA surcharges do not currently appear as a separate line item on customer bills but are instead embedded in the "Energy Charge" line item together with the Distribution Energy Charge and the DDOT Underground Electric Company Infrastructure Improvement Charge Recovery.[325]

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321 PEPCO (E): Bonikowski Direct at 65:7-9. This enhancement was also included in the TTYCF. PEPCO (2E): Bonikowski Supp. Direct at 24:3-25:4. For Schedules GS LV, GS 3A, MGT LV, GT LV, and GT 3A, the resulting BSA surcharge would include both a per-kWh and per-kW charge. For Schedule GT-3B, the BSA surcharge would solely be recovered through a per-kW charge, as this class does not have a distribution energy charge. *Id*. at 65:9-13. The portion of the BSA deferral balance eligible for recovery in a given period will be allocated between energy and demand charges based on the proportion of non-customer charge distribution revenues forecasted to be collected from each charge type in the corresponding rate year of the Company's MYP and these allocated costs will then be divided by the Company's billing determinant forecast for the applicable period to calculate the BSA surcharge rates. *Id*. at 66:1-10.

322 OPC (A): Dismukes Direct at 11:1-2; 108:6-13.

323 AOBA (A): B. Oliver Direct at 65:15-16.

324 AOBA (A): B. Oliver Direct at 65:14-22.

325 PEPCO (E): Bonikowski Direct at 66:13-14 & n.57.

To enhance bill transparency for customers, Pepco proposes to separate the BSA surcharge onto a separate line item on customer bills.[326]

OPC Witness Dismukes indicates that, if the BSA is continued, OPC supports Pepco's proposal to display BSA surcharges as separate line items on customer bills.[327] AOBA Witness B. Oliver is also supportive of this proposed enhancement.[328]

The Company's proposal to include the BSA surcharges as separate line items of customers' bills is reasonable and should be adopted.

5. *AOBA's suggestion that the BSA only be applied to classes with large numbers of comparatively small users should be rejected.*

AOBA Witness B. Oliver argues that, if the BSA is continued, then it should only apply to classes dominated by large numbers of comparatively small users.[329] However, this would serve to undercut the BSA's effectiveness in allowing Pepco to support programs that decrease customer usage and advance the District's public policy goals without incurring financial harm as it would reinstate the link between the Company's distribution revenue and electricity usage for the commercial classes that AOBA would exclude from the BSA.[330] Moreover, attainment of the District's climate goals will require action from all customer classes.[331] AOBA's suggestion runs

326 PEPCO (E): Bonikowski Direct at 66:14-16. For classes where Pepco would add a demand component to the BSA surcharge, bills would include separate line items for both the energy and demand BSA surcharges. *Id*. at 16-18. This enhancement was also included in the TTYCF. PEPCO (2E): Bonikowski Supp. Direct at 25:7-12.
327 OPC (A): Dismukes Direct at 11:1-2; 108:6-13.
328 AOBA (A): B. Oliver Direct at 66:13-14.
329 AOBA (A): B. Oliver Direct at 67:5-8. In response to Pepco DR 1-21, AOBA indicated that, if the BSA is continued, it should apply only to Schedules R, MMA, GS ND, and "possibly GT 3B. *See* PEPCO (3E)-16.
330 PEPCO (3E): Bonikowski Rebuttal at 35:12-36:2.
331 PEPCO (3E): Bonikowski Rebuttal at 35:14-15.

counter to the Clean Energy DC plan, which identifies improved building energy performance and energy efficiency upgrades as being critical to achieving carbon neutrality.[332]

6. *AOBA's concerns regarding Pepco's monthly BSA filing since April 2023 are misplaced as Pepco has used the Commission approved revenue per customer in each of its monthly BSA filings.*

AOBA Witness B. Oliver erroneously claimed that since April 2023, Pepco has "unilaterally increased its representations of authorized revenue per customer amounts for several major rate classes" by using revenue per customer targets in its monthly BSA reports greater than those provided in Pepco's January 11, 2023 Compliance Filing in FC 1156.[333] However, as Company Witness Bonikowski explained, each of Pepco's monthly BSA filings has used the applicable BSA revenue per customer targets approved by the Commission.[334] Because 5-year EDIT credits embedded in the Company's approved BSA targets for certain rate classes have been exhausted, the applicable BSA targets need to be updated coincident with the termination of any EDIT credits. AOBA's concern ignores that the Commission has reviewed and approved the elimination of these EDIT credits and each of the updated BSA targets.[335] The Commission approved BSA targets have been used in Pepco's monthly BSA reports. AOBA's concerns are baseless and should be rejected.

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332 PEPCO (3E): Bonikowski Rebuttal at 35:17-36:1.

333 AOBA (A): B. Oliver Direct at 62:12-63:8.

334 PEPCO (3E): Bonikowski Rebuttal at 36:11-12.

335 PEPCO (3E): Bonikowski Rebuttal at 36:11-37:11. *See* FC 1150, 1151 & 1156, Order Nos. 21594; 21639; 21892; and 21964 . For example, in Order No. 21964, the Commission indicated:

> According to Pepco, when these EDIT credit rates are adjusted, the BSA targets must be prospectively updated to reflect the new rates. Attachment C of the Filing provides Pepco's recalculated BSA targets for Schedule GS-3A to be effective April 1, 2024. We note that Pepco correctly continues to use the distribution rates and forecasts approved by the Commission in Order No. 21563 to calculate these updated BSA targets. We have reviewed and are satisfied with Pepco's documentation which supports the Company's proposals and conclusions. We, therefore, grant Pepco's request.

Order No. 21964 at ¶12 (footnote omitted).

I. Pepco's Proposed Return on Equity ("ROE") Is Supported by The Record and Is Reasonable.

Pepco established that an overall rate of return of 7.77% for 2024, 7.78% for 2025 and 7.79% for 2026 requested in the MYP Proposal is reasonable.[336] This overall rate of return was the weighted average, based on a capital structure of 50.50% common equity and 49.50% long-term debt, its budgeted embedded cost of long-term debt cost of 4.99% in 2024, 5.02% in 2025 and 5.04% in 2026 and the Company's requested ROE of 10.50%.[337]

Pepco demonstrated that the Company should be authorized to earn an ROE of 10.50% in connection for the MYP Proposal.[338] Applying legal standards that are not in dispute,[339] Company Witness McKenzie determined that an ROE of 10.50%, within a range of 9.9% to 11.10%,[340] was reasonable based on the application of market-based data to five widely accepted methods of determining ROEs: the Discounted Cash Flow ("DCF") model;[341] the Capital Asset Pricing Model ("CAPM");[342] the Empirical Capital Asset Pricing Model ("ECAPM");[343] the Risk Premium

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336 PEPCO (C): Holden Direct at 16, Table 3.
337 PEPCO (C): Holden Direct at 16, Table 3.
338. PEPCO (F): McKenzie Direct at 3:24-4:10; 8:13-9:10.
339 In addition to adhering to the standards derived from the U.S. Supreme Court's decisions in *Bluefield* and *Hope*, the Commission's decisions consistently follow the well-settled standards established in *Washington Gas Light Co. v. Public Service Commission,* 450 A.2d at 1209-1215. *See, e.g.,* FC 1139, Order No. 18846 at ¶250; FC 1103, Order No. 17424 at ¶226. As the Commission explained:

> The Commission determines the Company's authorized overall rate of return by the "cost of capital" method. That method seeks to determine what return the Company must offer its investors in order to attract the capital investment in its stocks and bonds necessary to finance its construction and operations. It is assumed that the cost of capital, when competently computed, is essentially and practically the equivalent of a fair rate of return. The overall cost of a utility's capital is calculated by determining the cost of each component in the company's capital structure. A weighted cost for each component is derived by multiplying its cost by its ratio to total capital. The sum of these weighted costs then becomes the utility's overall rate of return, which is multiplied by the company's rate base to determine the company's required return.

FC 1139, Order No. 18846 at ¶250 (footnotes omitted).
340 PEPCO (F): McKenzie Direct at 8:26-9:2; PEPCO (F)-2.
341 *See generally*, PEPCO (F): McKenzie Direct at 34:12-41:16; PEPCO (F)-5.
342 *See generally*, PEPCO (F): McKenzie Direct at 41:17-45:24; PEPCO (F)-7.
343 *See generally*, PEPCO (F): McKenzie Direct at 46:1-47:25; PEPCO (F)-8.

method;[344] and the expected earnings method[345] interpreting the results in the context of existing and expected market conditions and relative to other appropriate benchmarks.[346] Company Witness McKenzie explained that it is customary to consider the results of multiple methods when evaluating a just and reasonable ROE as consideration of the results of alternative approaches reduces the potential for error associated with any single method.[347] He also examined the DCF analysis for a group of low-risk firms in the competitive sector (the "Non-Utility Group") as an additional benchmark in evaluating a fair ROE for Pepco.[348]

The cost of capital (both debt and equity) has increased significantly since the Commission approved a 9.275% ROE for the Company in 2021 in FC 1156.[349] Between June 2021 and December 2023, the yield on 10-year Treasury Bonds, 30-year Treasury Bonds and Baa rated utility bonds increased by 250, 198 and 227 basis points, respectively.[350] During the same period, the Federal Funds rate increased from 0.13% to 5.38%.[351] Adjusting Pepco's 9.275% ROE approved in FC 1156 for the increase in capital costs that has occurred since June 2021 would result in an ROE of 10.48%.[352] Similarly, since FC 1139, in which the Commission left Pepco's

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344 *See generally*, PEPCO (F): McKenzie Direct at 48:1-50:25; PEPCO (F)-9.

345 See generally, PEPCO (F): McKenzie Direct at 51:1-53:2; PEPCO (F)-10.

346. PEPCO (F): McKenzie Direct at 3:24-26; PEPCO (F)-2.

347 PEPCO (F): McKenzie Direct at 31:22-33:19. Incorporating a range of valid approaches that OPC and AOBA ignored in their analyses enhances the accuracy of the ultimate ROE conclusion presented by Company Witness McKenzie. PEPCO (3F): McKenzie Rebuttal at 38:1-2.

348 PEPCO (F): McKenzie Direct at 53:5-9. As Mr. McKenzie explained, while he did not base his recommendation on this analysis, it is a relevant benchmark to ensure that the resulting ROE meets regulatory standards.

349 PEPCO (3F): McKenzie Rebuttal at 8:4-5.

350 PEPCO (3F): McKenzie Rebuttal at 7, Table AMM-R1. Company Witness McKenzie explained that it took 22 years for interest rates to fall by one half, but more recently the Baa utility bond yield has almost doubled in just 22 months. *Id*. at 16:4-5.

351 PEPCO (3F): McKenzie Rebuttal at 7, Table AMM-R1.

352 PEPCO (3F): McKenzie Rebuttal at 27:8-13; PEPCO (3F)-2.

ROE unchanged at 9.5%, the yields on public utility bonds have increased over 120 basis points and the midpoint of the target range for the Federal Funds rate has increased 425 basis points.[353]

On its face, AOBA's suggestion that Pepco's ROE should be reduced to 9.10% is unreasonable and contrary to objective, real-world measures. It is implausible that Pepco's ROE could have decreased from the level approved in FC 1156 when other capital costs have increased significantly.[354] Moreover, AOBA's ROE recommendation is not based on the analysis performed by AOBA Witness T. Oliver. AOBA's DCF and CAPM analyses indicated an even lower and more unreasonable range of 8.589% to 8.94% and an average of 8.876%.[355] Instead, AOBA's ROE suggestion of 9.10% is the midpoint between 8.876% and the 9.275% approved in FC 1156. AOBA Witness T. Oliver claims his suggestion was sensitive to the application of gradualism but fails to address how a decrease in the Company's authorized ROE is justified when interest rates are 225 basis points **higher** than when FC 1156 was decided.[356]

OPC's suggestion to only increase Pepco's ROE to 9.35% for the MYP is also unreasonably low given current market conditions and would not provide a fair ROE.[357] As the Commission explained in FC 1139:

> It is generally agreed that a financially sound utility is in the best interest of all ratepayers. A financially sound utility usually will attract investors and acquire

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353 PEPCO (3F): McKenzie Rebuttal at 19:9-13.

354 As Company Witness McKenzie noted, AOBA's ROE recommendation is unmoored from fundamental principles of finance and violates the basic, common-sense relationship between interest rates and the cost of equity. PEPCO (3F): McKenzie Rebuttal at 10:10-11:2.

355 AOBA (B): T. Oliver at 22:9-11.

356 PEPCO (3F): McKenzie Rebuttal at 26:13-19.

357 PEPCO (3F): McKenzie Rebuttal at 3:2-5:5. Company Witness McKenzie reported that objective evidence establishes that long-term capital costs (including the ROE) have increased substantially, and that investors expect these higher capital costs to be sustained at least through 2029. *Id*. at 12:1-4 and Table AMM-R2. He also explained that because capital market conditions have changed dramatically, recent historical allowed ROEs significantly understate investors' current required returns. *Id*. at 15:8-12.

debt at low interest rates. This benefit is passed onto ratepayers through lower rates.[358]

The Company's proposed ROE of 10.50% is based on sound data and analyses and is consistent with current and expected capital market conditions and is, therefore, reasonable and should be approved by the Commission.

J. Adoption of an MYP Does Not Require a Reduction in the Company's ROE.

Company Witness McKenzie showed that the companies in his proxy group ("Electric Group") operate under a wide variety of cost adjustment mechanisms, including decoupling and infrastructure cost trackers, and the vast majority of them operate in regulatory jurisdictions that allow for future test years, formula rates, and MYPs.[359] While investors would consider Pepco's regulatory mechanisms, including its MYP, to be supportive of the Company's financial integrity, this does not provide a basis to distinguish the risks of Pepco from the utilities in the Electric Group.[360] The mitigation in risks associated with the Company's regulatory mechanisms, including the MYP, is already reflected in the results of Company Witness McKenzie's ROE analyses and, therefore, no further adjustment is justified or warranted.[361]

There is no evidence that implementation of the MYP has had a measurable impact on Pepco's overall investment risks or would otherwise distinguish the Company from the utilities in the Electric Group.[362] Indeed, while the Company's ability to actually earn its allowed ROE in

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358 FC 1139, Order 18846 at ¶292.

359 *See generally*, PEPCO (F): McKenzie Direct at 25:13-27:13; PEPCO (F)-3.

360 PEPCO (F): McKenzie Direct at 27:14-17.

361 PEPCO (F): McKenzie Direct at 9:7-10, 29:9-13. Company Witness McKenzie indicated that although Pepco currently operates under MYPs in both the District of Columbia and Maryland, the Company's credit ratings have remained unchanged. *Id*. at 28:5-7.

362 PEPCO (F): McKenzie Direct at 28:7-10. All of the proxy group firms benefit from a wide variety of regulatory provisions that mitigate the impact of earnings attrition and regulatory lag. PEPCO (3F): McKenzie Rebuttal at 21:10-12.

the District has improved since the adoption of an MYP in FC 1156, Pepco's inability to recover carrying costs associated with deferral balances under the BSA has a significant negative impact on the Company's earnings and cash flows.[363]

The other parties present no evidence that would support a downward adjustment to the Company's ROE due to an MYP or that Pepco's MYP distinguishes it in any meaningful way from the companies in the Electric Group.[364] Not only do the majority of the firms in the Electric Group have operating subsidiaries that benefit from similar provisions, S&P has indicated that MYPs are "a common form of alternative regulation."[365] Furthermore, other regulatory commissions have determined that approval of an MYP does not warrant a downward adjustment in a public utility's authorized ROE.[366]

In similar circumstances in FC 1139, the Commission determined that no reduction in the Company's authorized ROE due to the BSA was warranted. The Commission explained:

> the Company has provided more evidence of the commonality of decoupling mechanisms in its proxy group, a proxy group deemed acceptable by the parties, whether the decoupling mechanism were full decoupling or partial decoupling. Since the majority of the companies in the Company's proxy group have some form of decoupling mechanism, the Commission agrees that some of the effects of decoupling mechanisms are reflected in the market data. The Company insists and we are persuaded that there is no reason to assume that Pepco is any less risky than its proxy group. Moreover, OPC and HCNCA provide little or no evidence to support their recommended 10-basis point reduction, and simply state that a 10-basis point reduction to the ROE is warranted because decoupling reduces risk and

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363 PEPCO (F): McKenzie Direct at 28:21-24.

364 PEPCO (3F): McKenzie Rebuttal at 28:4-29:2; PEPCO (F)-4.

365 PEPCO (3F): McKenzie Rebuttal at 29:9-11 (quoting S&P Global, *Major energy utility cases in progress in the US*, RRA Regulatory Focus (Oct. 4, 2023)).

366 PEPCO (3F): McKenzie Rebuttal at 29:12-19. For example, the North Carolina Utilities Commission ("NCUC") indicated in 2023 that approval of an MYP did not warrant a downward adjustment to the ROE, as "similar types of mechanisms are prevalent across the industry as well as within the proxy group" used in that proceeding. NCUC Docket No. E-2, Sub 1300, *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice* at page 169 (Aug. 18, 2023).

> the reduced risk should reflect a lower required ROE return by investors. Accordingly, we find that no further adjustment to the ROE is warranted.[367]

For similar reasons, the Commission in this case should find that adoption of an MYP does not require a reduction in Pepco's ROE.

K. The Company's Distribution Revenue Allocation Is Fair, Equitable, and Achieves Gradualism to Mitigate Rate Impacts.

The Company's residential rate class has provided a negative unitized rate of return (UROR) in every rate case since Pepco divested its generation assets in 2000. The UROR is a ratio of each rate class's individual rate of return compared against the system average rate of return provided by all classes, and indicates whether a given rate class is contributing more or less than the costs Pepco incurs to provide service to that class. A UROR greater than 1.0 means that the rate class contributed more than its fully allocated cost of service, while a UROR less than 1.0 means that the rate class contributed less than its fully allocated cost of service.[368] Classes with URORs below 1.0 are, in effect, subsidized by classes with URORs above 1.0. The subsidy provided to residential customers, primarily by commercial customers, has increased over the last 20 years from approximately $47 million in 2002 to over $132 million in 2021. This level of subsidy is not sustainable. Pepco submits that the Commission should equitably address the commercial classes' subsidization of the residential class given the economic impact of the COVID-19 pandemic on commercial customers in the District that caused a drastic reduction in commercial building use and subsequent struggle to maintain occupancy – difficulties that will not be alleviated soon.[369]

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367 FC 1139, Order No. 18846 at ¶294.

368 PEPCO (E): Bonikowski Direct at 6:14-21.

369 PEPCO (A): O'Donnell Direct at 48:13-49:5.

The Commission has previously recognized the equity concerns implicated by these subsidies in FC 1076:

> Historic rate patterns in the District of Columbia have been that the residential classes pay lower class RORs than the commercial class RORs. The Commission is not compelled to equalize class RORs for residential and commercial retail Pepco customers. We believe, however, that the severe disparities in class RORs that now exist call for corrective action.[370]

The Commission reiterated this need to address subsidization in FC 1103:

> Requiring other rate classes (primarily the commercial classes) to substantially subsidize the cost of serving residential customers over an extended period of time has raised questions of equity in a system that seeks to align rates with cost-causation. It harms the reputation of the District as a business friendly environment at a time when the District is trying to attract new businesses to improve the District's job market, as AOBA has argued.[371]

The Commission has consistently stated its policy to mitigate the residential subsidy gradually over time.[372] To this end, the Commission has previously allocated a greater portion of Pepco's incremental revenue requirement to residential classes as compared to commercial classes, including 45 percent and 43 percent residential revenue allocations in FC 1076 and FC 1103. In this instant proceeding, the Company proposes allocating approximately 43 percent of the distribution revenue requirement increase, or 2.3 times the system average revenue increase, to the residential class.[373] Further, the Company's proposal leverages the three-year construct of the MYP by spreading the proposed residential revenue increase evenly over each year of the MYP.

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[370] FC 1076, Order No. 15710 at ¶342.
[371] FC 1103, Order No. 17539 at ¶94.
[372] FC 1103, Order No. 17539 at ¶94.
[373] PEPCO (E): Bonikowski Direct at 17, Table 3; The Company's revenue allocation proposal is reasonable and utilizes the same Four-Step methodology approved by the Commission in FC 1156. The Company proposes that under-earning classes (i.e., SchedulesR, SL-E, and SL-S) receive a rate increase of 2.3 times the system average. Additionally, the Company applies a revenue decrease to rate classes with URORs in excess of 3.0 (i.e., Schedules GS 3A and TN) to reduce these classes URORs to 1.5.

The Company's proposal is fair and equitable because it gradually reduces the residential subsidy over time consistent with the Commission's stated policy and the principle of cost causation, while spreading the resulting residential bill impacts evenly over the MYP to achieve gradualism. The Commission should approve the Company's revenue allocation because it is reasonable and it works to mitigate commercial class subsidization of the residential class.

L. The Absence of Proposed New Performance Incentive Mechanisms Is Not a Reasonable Basis to Reject Pepco's MYP.

When Pepco's application for the Climate Ready Pathway was filed in April 2023, the Performance Incentive Mechanism (PIMs) Working Group had not yet submitted its report to the Commission regarding Phase 2.[374] That PIMs Working Group report filed with the Commission on October 31, 2023. As of the date of this Brief, the Commission is still considering the Phase 2 report of the PIMs Working Group and its recommendations on the range of issues identified in Order No. 21416. As such, and as Company Witness O'Donnell explained in her Direct Testimony, "the Commission has not had an opportunity to consider any recommendations that may result from [the PIMS Working Group] process. Given this, it would have been premature to propose new PIMs in this proceeding." This remains true today. In fact, Pepco recently responded to a Commission Staff data request seeking more information regarding the reporting data for the tracking PIMs. Proposing new PIMs before knowing the structure of the original PIMs and having them in place risks creating duplicative work and unintended consequences. The Commission may approve the MYP and later add PIMs resulting from the PIMs Working Group process. In fact,

[374] In Phase 2, the working group was to develop consensus and non-consensus recommendations for turning the current performance tracking mechanisms into fully functioning PIMs.

this is what the PIMs Working Group envisioned, which is that, once the PIM is established and authorized, it will be applied in the annual reconciliation process for an MYP.[375]

As Pepco explained in its March 22, 2024 Response, approval of the MYP is not contingent on the inclusion of proposed PIMs.[376] First, although the Commission has recognized that PIMS are important,[377] they are not one of the ten items in the framework adopted in the AFOR Order.[378] Moreover, the Commission has been clear that the framework principles identified in the AFOR Order are not brightline requirements that must all be met in any AFOR application.[379]

Second, the FC 1156 MYP the Commission approved in 2021 did not include PIMs.[380] Instead, the Commission implemented tracking PIMS, which amounts to additional reporting requirements, that were focused on the District's climate change and clean energy goals.[381] In Order No. 20755, the Commission indicated that the tracking PIMs it adopted would "provide the Commission and the Parties an opportunity to assess how PIMs can efficiently incentivize our

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375 See FC 1156, Phase Two of the Second Performance Incentive Mechanism Working Group Report at 35 (October 31, 2023).
376 FC 1176, *Response of Potomac Electric Power Company in Opposition to the Motion to Dismiss or, in the Alternative, Motion for Summary Disposition* at 6-9.
377 The Commission has indicated that "properly designed PIMs represent an important tool to align utility incentives with public policy goals, such as the District's aggressive clean energy and environmental goals." AFOR Order at ¶101. The Commission also noted that "the development of PIMs is more of an art than a science." *Id*.
378 The framework principles are set forth in Paragraph 96 of the AFOR Order. Paragraph 103 in the AFOR Order discusses broad general guidelines for developing PIMs; however, the Commission noted "the complexity of developing suitable and meaningful PIMs."
379 Order No. 20755 at ¶32 ("Order No. 20273 is a policy decision which sets principles and guidelines rather than bright-line requirements").
380 OPC argued in FC 1156 that, if the Commission approved an MYP, it should reject the PIMs that Pepco had proposed to accompany the MYP. OPC's Initial Brief at 123. AOBA also argued in FC 1156 that the PIMS Pepco had proposed to accompany its MYP should be rejected. FC 1156 AOBA (A) at 15.
381 The Commission explained that the tracking PIMS "would be more useful in aiding the Commission and stakeholders in identifying what elements are appropriate to measure PIMs and how to structure financial rewards or penalties for implementing fully functional PIMs." 20755 at ¶168.

utilities to move aggressively in achieving the District's climate and clean energy goals."[382] The Commission also explained that the tracking PIMS it had adopted would: "ultimately evolve into a system of fully functional incentive and penalty mechanisms, as measurement systems and implementation procedures are collaboratively developed."[383]

The PIMs Working Group was an integral part of that development process. In its decision in FC 1156, the Commission initially directed that the PIMs Working Group it had established earlier in the proceeding to, *inter alia*, propose the data measurement methodologies for each of the tracking PIMs the Commission adopted.[384]

The Phase 2 report's recommendation also highlights that the MYP's structure, which incorporates an annual reconciliation process, lends itself to the integration of PIMs into the MYP. In fact, the Commission recognized that it could implement modifications to the tracking PIMs adopted in FC 1156 during the term of that MYP, noting in Order No. 20755 that it "reserve[d] the ability to harmonize the PIMs, if needed, with other decisions issued from related case dockets."[385]

Thus, the Commission may approve the MYP and subsequently add PIMs that it determines should be implemented as a result of recommendations received from the PIMs Working Group process. In this regard, Pepco proposes that the Commission reconvene the PIMs Working Group to discuss the specifics needed to implement a Non-Wires Alternative ("NWA") PIM, originally proposed by DCG Witness Lane in her direct testimony.[386] Under DCG's

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382 Order No. 20755 at ¶474. The Commission expressly held that the FC 1156 MYP and the tracking PIMS adopted in FC 1156, "represent a first step in advancing the District's climate goals and implementing alternative forms of regulation for electric rates." *Id*. at ¶476(f).

383 *Id*. at ¶9.

384 *Id*. at ¶173.

385 Order No. 20755 at ¶10.

386 DCG (A): Lane Direct at 26:3-29:8.

proposal, the NWA PIM would support increasing investment in cost-effective NWAs by rewarding Pepco for each cost-effective NWA[387] implemented using a "shared savings" mechanism.[388] While the Company may disagree with Witness Lane regarding her justification for the proposal,[389] because Pepco does include the consideration of NWAs in its current planning process, the Company sees DCG's proposal as a way to possibly strengthen the commitment to NWAs and further align with District clean energy policies.

Pepco recommends that the Commission convene the PIMs Working Group for a limited duration – such as 90 days – to discuss specifics related to the potential implementation of an NWA PIM, including the proposals identified by DCG Witness Lane as well as those of Pepco and other stakeholders.

M. The MYP Appropriately Includes Projects That Support the District's Climate and Decarbonization Goals; Deferral to the Climate Solutions Program Docket Is Not Appropriate.

During the Hearing, the Company was asked whether, in light of the decision in Washington Gas Light Company's ("WGL") last rate case, FC 1169, the inclusion of projects that advance the District's climate and clean energy goals in the MYP should have been deferred until the Commission's decision in FC 1167.[390] Order No. 21939 deciding FC 1169 was issued on December 22, 2023, more than 8 months **<u>after</u>** Pepco's Climate Ready Pathway was filed on April 13, 2023 and therefore was not considered in preparing the Company's application. However, in Order No. 21939, the Commission did not indicate that FC 1167 was the sole proceeding in which

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387 *Id.* at 26:3-5.
388 *Id.* at 28:7-14.
389 *Id.* at 26: 21-22.
390 Tr. at 47-49.

programs that support the District's climate and clean energy goals could be considered and approved, rather the Commission refers to FC 1167 "or other proceedings."[391] Additionally, in FC 1169, as the Commission noted, WGL was proposing to establish a new funding mechanism, the Climate Action Recovery Tariff ("CART"), for future climate initiatives that WGL would implement. WGL's future programs, however, were not a part of FC 1169, only the CART surcharge mechanism that would have begun collecting funds from customers was included in the case. The Commission rejected this approach, holding that "there should be no cost recovery for these unapproved programs at this time."[392]

Unlike WGL's CART in FC 1169, Pepco's MYP does not propose a surcharge mechanism separate and apart from programs that would be proposed and approved later in another docket. As Company Witness O'Donnell explained in her Rebuttal Testimony not only has the Company pursued and implemented a suite of Commission-approved electric vehicle programs in FC 1155, it has proposed energy efficiency programs that are pending before the Commission in FC 1160 as well as a range of programs focused primarily on transportation and building electrification that were proposed in the Climate Solution Plan ("CSP") Phase 1 Application submitted in FC 1167.[393] She indicated that these latter programs are not capital investments that require extensive planning, design, engineering and construction that will occur over multiple years. Rather, the CSP Phase 1 Application programs are customer-incentive and education programs that Pepco has the ability to plan and implement more quickly to help its customers pursue electrification and support the

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391 Order No. 21939 at ¶430.

392 *Id*.

393 PEPCO (4A): O'Donnell Rebuttal at 14:22-15:1. The 11 programs included in Pepco's CSP Phase 1 Application were identified in the Company's Climate Solutions 5-Year Action Plan filed on October 8, 2021 in FC 1167.

District's climate objectives.[394] As discussed in the CSP Phase 1 Application, recovering for these programs through a surcharge provides a flexible mechanism by which customers can access incentives and educational information to drive immediate adoption of new technologies to keep pace with evolving policy and technology changes. Given the pace of legislative and technological developments impacting decarbonization, the Commission's review and approval of innovative programs should not be constrained to a cycle of several years.[395]

N. Pepco's Depreciation Study and Proposed Depreciation Rates Are Reasonable.

Company Witness Allis presented the depreciation study performed for Pepco entitled "Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2021" ("Depreciation Study").[396] He indicated that the depreciation rates use the same methods for estimating service lives, net salvage, and calculating depreciation for the original cost of plant that have been used in previous Pepco depreciation studies.[397] Consistent with Commission precedent,[398] the proposed depreciation rates are based on the DC Present Value Method.[399] For the MYP, Pepco proposes to use the depreciation rates determined in the

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394 PEPCO (4A): O'Donnell Rebuttal at 15:5-9.

395 CSP Phase 1 Application, PEPCO(A) at 28.

396 The Depreciation Study was provided as PEPCO (L)-1. The study was originally filed in FC 1156 on January 31, 2023. PEPCO (L): Allis Direct at 3:20-21. The Company's last depreciation study was performed based on data through December 31, 2016. Pepco's current depreciation rates were approved in 2018 in FC 1150 and have been in effect for more than five years. *Id*. at 12:5-7. Company Witness Allis explained that Pepco's Depreciation Study, is near the upper end of the time frame between studies that is most appropriate. *Id*. at 12:20-22.

397 PEPCO (L): Allis Direct at 4:18-20.

398 FC 1076, Order No. 15710 at ¶252.

399 PEPCO (L): Allis Direct at 4:22-5:2. This is a present value method for determining net salvage that discounts future net salvage costs for the purposes of calculating depreciation expense. *Id*. at 23:8-14. The Commission's stated objective in adopting this net salvage method appears to have been to produce net salvage depreciation accruals that resulted in customers paying equal amounts of depreciation expense in inflation-adjusted terms over the lives of the Company's assets. *Id*. at 26:11-27:4. In addition to the depreciation expense that results from the use of the DC Present Value Method with a 2.5% inflation-based discount rate, the Depreciation Study also provides the depreciation rates and accruals resulting from discount rates for each account derived from the Handy Whitman Construction Indexes as well as the traditional straight-line method. *Id*. at 28:6-29:11; PEPCO (L)-1; PEPCO (L)-3.

Depreciation Study using the DC Present Value Method with a 2.5% inflation-based discount rate.[400] Company Witness Allis indicated that the depreciation rates Pepco is proposing for the MYP are at the lower bound of the range of reasonableness because he anticipates that depreciation rates will need to increase in the future because the DC Present Value Method does not recover a sufficient level of net salvage as well as the impacts of shorter lives of new assets likely needed to meet the District's decarbonization goals.[401] He identified the primary drivers of Pepco's proposed increase in depreciation as: 1) past under-recovery of depreciation expense;[402] 2) more negative net salvage estimates; and 3) updates to the inflation-based discount rates used for the DC Present Value Method.[403]

OPC was the only party to directly challenge the Company's Depreciation Study and its proposed depreciation rates.[404] Although OPC Witness Andrews supported the method, procedure and technique used in the Depreciation Study and indicated that the calculations therein were performed correctly,[405] he argued that the depreciation rates were overstated. Specifically, he suggested that depreciation rates should reflect: (1) adjustments to the average service lives for several accounts, (2) adjustments to the net salvage rate for Account 362, and (3) the use of the

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400 PEPCO (L): Allis Direct at 13:11-13 and Table 1. Company Witness Allis indicated that the proposed discount rate was based on both historical and projected long-term inflation. *Id*. at 27:20-28:2.

401 PEPCO (L): Allis Direct at 21:10-21. Company Witness Allis explained that the most common and widely accepted method of estimation for net salvage is that estimates are based on an analysis of historical net salvage data, and historical cost of removal and gross salvage are expressed as a percentage or ratio of historical retirements. *Id*. at 24:11-16. This is well understood to typically result in conservative (i.e., less negative) estimates of future net salvage. *Id*. at 24:17-19.

402 Company Witness Allis explained that Pepco has spent millions of dollars more in net salvage than it has recovered through depreciation and, due to this under recovery, depreciation rates using the remaining life technique need to adjust higher to account for these past under-recoveries. PEPCO (2L): Allis Rebuttal at 2:14-17.

403 PEPCO (2L): Allis Rebuttal at 2:10-12.

404 *See generally*, OPC (D): Andrews Direct.

405 OPC (D): Andrews Direct at 13:18-20.

Handy-Whitman inflation rates to discount net salvage costs.[406] OPC's proposed adjustments would reduce the overall depreciation rate from 3.08% as set forth in the Depreciation Study to 2.56%.[407] Company Witness Allis addressed each of OPC's adjustments in Rebuttal Testimony and explained why they were inappropriate and inconsistent with the reality of Pepco's operating environment.[408] For example, Company Witness Allis explained that achieving net zero emissions and transitioning to a decarbonized energy system over the next two decades will have significant impacts on the electric distribution system. The energy transition will result in increased rates of replacements and retirements of electric distribution assets due to factors such as load growth, winter peaking, resiliency and reliability investments, new technologies, and functional and technological obsolescence.[409] This will, in turn, either reduce or limit the service lives of many of the Company's assets.[410] OPC's proposed extensions of the average service life do not fully incorporate considerations about the operating characteristics of the account assets or the ways the

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406 OPC (D): Andrews Direct at 3:6-18, 14:12-15. OPC Witness Andrews' Depreciation Study is presented in OPC (D)-3.

407 The net effect of OPC's proposed adjustments to depreciation rates would be to reduce depreciation expenses over the term of the MYP by $26.37 million in 2024, $28.25 million in 2025, and $29.87 million in 2026. OPC (D): Andrews Direct at 3:26-28; OPC (D)-5. Under the TTYCF, depreciation expense would be reduced by $24.52 million. *Id*. at 3:24-25; OPC (D)-4.

408 Company Witness Allis addressed why the average service lives Pepco used to set depreciation rates are reasonable and more appropriate than those proposed by OPC. *See generally*, PEPCO (2L): Allis Rebuttal at 3:1-20:2. He also explained why Pepco's net salvage rate for Account 362 is superior to that proposed by OPC. *See generally, id*. at 27:21-28:14. Finally, Company Witness Allis explained that, contrary to OPC's assertions, the Commission has not precluded Pepco from proposing the use of a CPI-based discount rate nor has the Commission previously ruled on this approach. Pepco's proposal to use CPI for the discount rate better aligns with the Commission's stated rational for adopting the DC Present Value Method while OPC's use of Handy Whitman Indices which include costs that are unrelated to price inflation or the cost of removal should be rejected. *See generally, id*. at 26:11-27:18.

409 PEPCO (2L): Allis Rebuttal at 5:13-19; 9:3-16.

410 For example, increased generation from intermittent sources requires more equipment for voltage support and new technologies. Electrification will result in both load growth and changes to the load profile as peaks occur at different times of year or in different geographical locations. Increased loading will also cause additional wear and tear on equipment such as transformers. Moreover, as the electric grid is modernized and more new technologies are added, this will lead both to retirements of existing assets and shorter lives for the newer technology assets. PEPCO (2L): Allis Rebuttal at 13:12-14:10.

future will be different from the past. The record establishes that the Depreciation Study and the depreciation rates set forth therein are reasonable and should be approved by the Commission.

O. The Company's Proposed MYP Ratemaking Adjustments Are Reasonable and The Vast Majority Are Not Disputed.

Company Witnesses Leming and Holden detailed the various ratemaking adjustments ("RMAs")[411] the Company included in the MYP and established that each was reasonable.[412] RMAs are generally adjustments to the per books/unadjusted rate base and operating income to adjust for cost disallowances for ratemaking purposes or to present approved or proposed ratemaking treatment of rate base or operating income items that differ from the per books amounts.[413] Of the 31 RMAs Pepco proposed, 28 are not challenged by any party.[414] Specifically, RMA 1 (Removal of DC Power Line Undergrounding (DC PLUG) Initiative Costs),[415] RMA 2 (Removal of Supplemental Executive Retirement Plan ("SERP") Costs),[416] RMA 3 (Removal of Executive Incentive Plan ("EIP") Costs),[417] RMA 4 (Removal of Adjustments to Deferred

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[411] RMAs are pro forma adjustments to the cost of service for various reasons including (but not limited to) known and measurable changes, normalization of costs, or, in some cases, to adjust the "per books" cost of service based on past Commission orders or practices regarding cost allowances and disallowances. PEPCO (B): Leming Direct at 47:13-16. For example, Pepco's projected costs in its MYP include items for which the Company is not seeking recovery, and, therefore, certain items need to be removed from the MYP through an RMA. *Id*. at 49:2-4. Some of the RMAs, including RMAs 11a, 13 and 14, only relate to the 2022 historic test year and are for the removal of non-recurring costs that will not be incurred during the MYP period (or the 2023 bridge period). *Id*. at 49:11-14.

[412] *See generally*, PEPCO (B): Leming Direct at 47:11-69:16; PEPCO (B)-1; PEPCO (C): Holden Direct at 5:1-14:15; PEPCO (C)-1; PEPCO (3B): Leming Rebuttal at Section III; PEPCO (3B)-1; PEPCO (3C)-1.

[413] PEPCO (C): Holden Direct at 5:5-9.

[414] For several RMAs relating to regulatory assets (RMA 17, 20, 23), although OPC did not challenge the adjustment itself, OPC did recommend that the regulatory asset be amortized over a six-year period rather than the 5-year period Pepco had proposed. OPC (B)-11. Although Company Witness Leming did not adopt OPC's recommendation, he did indicate that OPC's proposed modification could be a reasonable alternative if the Commission is inclined to adopt the approach. *See,* PEPCO (3B): Leming Rebuttal at 27:2-3. Additionally, although no party contested the methodology used to determine RMA 28, other adjustments that are contested impact the amount of RMA 28.

[415] PEPCO (C): Holden Direct at 5:18-6:1; PEPCO (C)-1, page 1 of 21.

[416] PEPCO (C): Holden Direct at 6:6-15; PEPCO (C)-1 at page 2 of 21.

[417] PEPCO (C): Holden Direct at 7:20-8:8:6; PEPCO (C)-1 at page 3 of 21.

Compensation Balances),[418] RMA 5 (Removal of Employee Association Costs),[419] RMA 6 (Removal of Industry Contributions and Membership Fees),[420] RMA 7 (Removal of Institutional and Institutional Advertising Expenses),[421] RMA 8 (Reflection of Customer Deposit Interest Expense and Credit Facility Expense and Maintenance Costs),[422] RMA 9 (Removal of Executive Perquisite Expenses),[423] RMA 10 (Adjustment to EBSC Billed Depreciation),[424] RMA 11a (Removal of Benning Environmental Accrual),[425] RMA 12 (Reflection of Benning Insurance Proceeds),[426] RMA 13 (Removal of Buzzard Point Environmental Remediation Costs),[427] RMA

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418 PEPCO (C): Holden Direct at 8:9-12; PEPCO (C)-1 at page 4 of 21.

419 PEPCO (C): Holden Direct at 8:14-18; PEPCO (C)-1 at page 5 of 21.

420 PEPCO (C): Holden Direct at 9:3-6; PEPCO (C)-1 at page 6 of 21.

421 PEPCO (C): Holden Direct at 9:9-15; PEPCO (C)-1 at page 7 of 21.

422 PEPCO (C): Holden Direct at 9:18-10:8; PEPCO (C)-1 at page 8 of 21.

423 PEPCO (C): Holden Direct at 10:11-14; PEPCO (C)-1 at page 9 of 21.

424 PEPCO (C): Holden Direct at 10:17-11:8; PEPCO (C)-1 at page 10 of 21.

425 PEPCO (C): Holden Direct at 11:13-12:2; PEPCO (C)-1 at page 11 of 21. RMA 11b had requested recovery of actual Benning RI costs from January 1, 2018 through December 31, 2022 and RMA 11c had requested recovery of forecasted Benning RI/FS costs through the first quarter of 2024 when the FS was anticipated to be completed. Pursuant to Order No. 21884 and affirmed in Order No. 21904, the Commission denied cost recovery of the RI costs for the Benning Road facility. Therefore, in accordance with the Commission's decision, in Rebuttal Testimony the Company removed any request for recovery in this proceeding of the costs that had been in RMA 11b and 11c through RMA 31. PEPCO (3B): Leming Rebuttal at 37:9-38-6, 41:3-6, Table 11; PEPCO (3B)-1.

426 Pepco has been diligently pursuing recovery of insurance proceeds for the costs of the environmental activities at the Benning Road facility and, as reported in the biannual filing in FC 1150/1151 submitted on December 28, 2022, the Company has successfully recovered $4.6 million in insurance proceeds, the District of Columbia portion of which is $2.7 million. PEPCO (B): Leming Direct at 54:2-8. Under Section 14d of the FC 1150 Settlement, Pepco agreed to return insurance proceeds to customers in subsequent rate proceedings to the extent necessary to reimburse customers for costs recovered through rates. RMA 12 as initially proposed reflected the return of $2.7 million consistent with Pepco's request for continued recovery of RI/FS costs. *Id*. at 54:2-55:4; PEPCO (B)-1 at page 10 of 23. However, in light of the Commission's decision in Order Nos. 21884 and 21904 to deny further cost recovery of the RI costs for the Benning Road facility, RMA 12 changed to reflect the return of $785,000 of insurance proceeds for the amount charged through rates until the regulatory asset amortization was paused beginning July 1, 2021 pursuant to Order No. 20755. PEPCO (3B): Leming Rebuttal at 38:13-17; PEPCO (3B)-1. Company Witness Leming explained that Pepco resumed amortization of the Benning RI costs regulatory asset approved under the FC 1150 Settlement on January 1, 2023 and, since then, rates have included $27.4 thousand per month of amortization. RMA 12 does not include an offset for this ongoing amortization as it is not known when the Commission will render a decision in this proceeding; however, it would be appropriate for the Commission to increase RMA 12 by $27.4 thousand per month for the period between January 1, 2023 and the rate effective date in this proceeding. PEPCO (3B): Leming Rebuttal at 38:17-39:6.

427 PEPCO (C): Holden Direct at 12:5-14; PEPCO (C)-1 at page 12 of 21.

14 (Removal of GAAP BSA Revenue Recognition Reserve),[428] RMA 16 (Reflection of Climate Solutions Plan (CSP) Programs),[429] RMA 17 (Reflection of Regulatory Asset for COVID-19 Related Costs),[430] RMA 18 (Reflection of Real Estate & Facility Costs),[431] RMA 19 (DER Interconnection Investments),[432] RMA 20 (EDIT Balance),[433] RMA 21 (House of Worship Credit),[434] RMA 22 (Reflection of Current Rate Case Costs),[435] RMA 23 (Reflection of Electric Vehicle Regulatory Asset),[436] RMA 24 (Small DER Cost Sharing Petition),[437] RMA 27 (Adjustments to Cash Working Capital Allowance),[438] RMA 28 (Tax Effect of Pro forma Interest

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428 Under the applicable GAAP revenue recognition guidance for regulated operations established in Accounting Standards Codification (ASC) 980-605-2528, any revenues recognized and deferred to a regulatory asset for collection associated with an Alternative Revenue Program are required to be collected within 24 months following the end of the annual period in which they are recognized. PEPCO (C): Holden Direct at 12:17-13:11. PEPCO (C)-1 at page 13 of 21. For ratemaking, these revenues are deferred to a Commission-approved regulatory asset and are authorized for collection through the BSA, and the Company has added the revenues back to the unadjusted HTY revenues. *Id*. at 13:12-14

429 PEPCO (B): Leming Direct at 59:20-60:2; PEPCO (B)-1 at page 12 of 23. *See also* PEPCO (J): Hightower Direct at 20:3-14.

430 PEPCO (B): Leming Direct at 60:21-64:1; PEPCO (B)-1 at page 13 of 23.

431 PEPCO (B): Leming Direct at 64:4-8; PEPCO (B)-1 at page 14 of 23. *See also* PEPCO (G): Vahos Direct at 50:8-52:8.

432 PEPCO (B): Leming Direct at 64:10-13; PEPCO (B)-1 at page 15 of 23. *See also* PEPCO (J): Hightower Direct at 20:3-24:4.

433 PEPCO (B): Leming Direct at 65:7-9; PEPCO (B)-1 at page 16 of 23.

434 PEPCO (B): Leming Direct at 65:16-19; PEPCO (B)-1 at page 17 of 23.

435 PEPCO (B): Leming Direct at 66:6-17; PEPCO (B)-1 at page 18 of 23. RMA 22 offsets against the current rate case cost estimates for this proceeding a regulatory liability of $196,000 for excess rate case costs associated with FC 1139 and 1150.

436 PEPCO (B): Leming Direct at 67:19-22; PEPCO (B)-1 at page 19 of 23.

437 PEPCO (B): Leming Direct at 68:3-69:9; PEPCO (B)-1 at page 20 of 23. RMA 24 is contingent upon the Commission's approval of Pepco's Small DER interconnection program. *See* RM40-2023-01 and ET2023-02, *Potomac Electric Power Company's Petition to Approve a Tariff Change for 20kw and Below Residential NEM Solar Interconnections* (April 4, 2023).

438 PEPCO (C): Holden Direct at 14:5-6; PEPCO (C)-1 at pages 15-18 of 21.

Expense),[439] RMA 29 (Reflection of Capital Project Updates),[440] RMA 30 (Removal of DC CREF Meters),[441] and RMA 31 (Removal of Benning RI/FS Regulatory Asset & Amortization)[442] were not challenged by any party.[443]

Only three of the Company's RMAs (RMA 15, 25 and 26) were directly challenged by parties and most of these were the result of other issues being disputed. For example, because OPC suggests changes to certain of the depreciation rates in Pepco's depreciation study, OPC proposes an adjustment to RMA 25 (Adjustments to Depreciation Rates) to reflect these changes.[444] As discussed in Section N and the Rebuttal Testimony of Company Witness Allis, the depreciation rate changes OPC has proposed are unreasonable and should be rejected. RMA 25 appropriately reflects the use of the updated depreciation rates presented in the depreciation study and is therefore reasonable and should be approved.

Similarly, AOBA argued that Pepco's lead-lag study[445] was heavily influenced by the effects of the COVID-19 pandemic and suggested that the study therefore be rejected and the 2017 lead-lag study from FC 1156 remain in place.[446] As discussed in the Rebuttal Testimony of

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439 PEPCO (C): Holden Direct at 14:11-15; PEPCO (C)-1 at pages 19-21 of 21. No party contested the methodology used to determine RMA 28; however, other adjustments that are contested impact the amount of RMA 28. For example, in Rebuttal Testimony Company Witness Leming changed RMA 28 to reflect the change to District of Columbia and federal income tax expense that resulted from the changes to rate base resulting from the updated RMAs he presented and their impact on interest expense. PEPCO (3B) at 39:9-11; Table 11.

440 PEPCO (3B): Leming Rebuttal at 39:13-40:7; PEPCO (3B)-1 at Page 22 of 26. Although RMA 29 was not contested, as discussed in Section D, some parties have challenged additional projects included in the Company's Construction Report.

441 PEPCO (3B): Leming Rebuttal at 40:9-16 & Table 11; PEPCO (3B)-1 at Page 23 of 26.

442 PEPCO (3B): Leming Rebuttal at 41:3-6.

443 *See* OPC (B)-2, AOBA (B)-3, Page 2 of 2.

444 OPC (B): Gorman Direct at 5:4-7 & Table 1; OPC (B)-2.

445 The Company's lead-lag study was presented by Company Witness Holden. PEPCO (C): Holden Direct at 22:14-23:15; PEPCO (C)-4. The study used the same methodology as the study that the Commission approved in FC 1139 and was the basis of the cash working capital adjustment in FC 1156. FC 1139, Order No. 18846 at ¶42; FC 1156, Order No. 20755 at ¶257.

446 AOBA (A): B. Oliver Direct at 80:17-81:12.

Company Witness Holden, AOBA's challenges to the Company's lead-lag study are baseless and should be rejected.[447] Pepco's lead-lag study is reasonable and appropriate for use in this proceeding.

Pepco's RMAs are reasonable and should be approved.

P. Pepco's O&M Projections Are Reasonable and Should Be Used for the MYP.

O&M expenses include the costs of labor, materials, and other expenses necessary to operate and maintain Pepco's electric distribution system.[448] In order to develop Pepco's District of Columbia distribution O&M costs for the 3-year term of the MYP, Pepco started with its Long Range Plan ("LRP"), which includes a projection of O&M expenses through 2026.[449] In addition to its own O&M costs, Pepco was allocated certain PHISCO and Exelon Business Services Company ("EBSC") shared services O&M.[450]

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[447] PEPCO (2C): Holden Rebuttal at 7:9-9:16. The Commission rejected similar arguments raised by AOBA in WGL's recent rate case. FC 1169, Order No. 21939 at ¶149.

[448] PEPCO (B): Leming Direct at 37:3-4.

[449] In addition to O&M, the PHI LRP also includes capital spend, financial statements (e.g., income statement, balance sheet, cash flows) and financial metrics. PEPCO (G): Vahos Direct at 10:20-22. The Company provided three different views of O&M in connection with the MYP: (1) a Management View which presents total Pepco direct O&M costs and total PHISCO incurred O&M costs (pre-Pepco allocation) at the Management Responsibility Area level (PEPCO (G): Vahos Direct at 11:2-13:22; Table 1; PEPCO (G)-2); (2) a Consolidated Pepco Reporting View which includes total Pepco direct O&M costs and the Pepco portion of total PHISCO incurred costs (direct billed and allocated) (PEPCO (G): Vahos Direct at Table 2); and (3) a Revenue Requirement View that reflects the Pepco Distribution O&M in the District of Columbia for which cost recovery is being requested (PEPCO (B): Leming Direct at 37:18-38:19 & Table 6; PEPCO (B)-4; PEPCO (G): Vahos Direct at Table 3 (comparing all three views)). The projections of Pepco's 2023-2026 O&M expenses are supported by the testimony of Company Witnesses Vahos (Non-Operations O&M expense – PEPCO (G)); Vavala (Electric Operations O&M expense -- PEPCO (I)); and Hightower (Customer Operations O&M expense – PEPCO (J)). PEPCO (B): Leming Direct at 37:9-14.

[450] The shared services Pepco receives from these service companies are delineated in the Alternate Integration Plan approved in FC 1119. PHISCO provides services only to PHI's three regulated subsidiaries: Pepco, Atlantic City Electric Corporation ("ACE"), and Delmarva Power & Light Company ("Delmarva Power"). PEPCO (G): Vahos Direct at 4:18-21. PHISCO costs are directly billed or allocated to Pepco pursuant to the Cost Allocation Manual (CAM). *Id*. at 4:21-22; PEPCO (B): Leming Direct at 72:13-73:15; PEPCO (B)-9. EBSC provides services to all Exelon companies, including Pepco. Some EBSC costs are directly billed or allocated to Pepco, while other EBSC costs are directly billed or allocated to PHISCO, and then to Pepco. PEPCO (G): Vahos Direct at 5:1-4. EBSC costs are directly billed or allocated to Pepco pursuant to the General Services Agreement (GSA). *Id*. at 5: 4-6; PEPCO (B)-9. *See also* PEPCO (3G): Vahos Rebuttal at 4:7-17.

Company Witness Vahos described the LRP process and the role of each responsibility area in the overall LRP development process.[451] The responsibility areas annually perform their budget and planning process based on ensuring safe and reliable service, business needs, upcoming projects/existing or new initiatives, regulatory/legal requirements, and established goals, and seek to keep O&M cost increases below the inflation rate.[452]

Company Witness Vahos provides information and data regarding actual 2022 O&M costs and O&M budgets for 2023 through 2026 for the following non-operational responsibility areas:[453] Communications;[454] Controllership;[455] Executive Management;[456] Finance;[457] Government, Regulatory and External Affairs;[458] Human Resources;[459] Legal;[460] Supply,[461] Support Services,[462] Real Estate and Facilities;[463] BSC Non-Information Technology;[464] and Information Technology.[465]

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451 *See generally*, PEPCO (G): Vahos Direct at III.

452 PEPCO (G): Vahos Direct at 13:11-14. Although actual O&M costs may differ from the projected level as a result of timing, unplanned or emergent events, and changes from where costs were originally budgeted, if variances occur, PHI looks to manage its spend at the total O&M level so that it stays on budget in terms of total PHI O&M across all responsibility areas. *Id*. at 14:3-12.

453 *See generally*, PEPCO (G): Vahos Direct at IV; PEPCO (G)-1; PEPCO (G)-2.

454 PEPCO (G): Vahos Direct at 18:1-20:14; PEPCO (G)-1; PEPCO (G)-2.

455 PEPCO (G): Vahos Direct at 20:15-21:21; PEPCO (G)-1; PEPCO (G)-2.

456 PEPCO (G): Vahos Direct at 22:1-19; PEPCO (G)-1; PEPCO (G)-2.

457 PEPCO (G): Vahos Direct at 22:20-24:22; PEPCO (G)-1; PEPCO (G)-2.

458 PEPCO (G): Vahos Direct at 25:1-31:5; PEPCO (G)-1; PEPCO (G)-2.

459 PEPCO (G): Vahos Direct at 31:6-32:12; PEPCO (G)-1; PEPCO (G)-2.

460 PEPCO (G): Vahos Direct at 32:13-33:10; PEPCO (G)-1; PEPCO (G)-2.

461 PEPCO (G)-2.

462 PEPCO (G)-2.

463 PEPCO (G): Vahos Direct at 33:11-34:14; PEPCO (G)-1; PEPCO (G)-2.

464 PEPCO (G): Vahos Direct at 34:15-37:4; PEPCO (G)-2.

465 PEPCO (G): Vahos Direct at 37:5-38:15. Company Witness Vahos discusses the IT Capital Expenditure process undertaken as part of the LRP. *Id*. at 39:3-44:11; PEPCO (G)-2. Company Witnesses Cantler, Vavala and Hightower address certain IT capital projects that relates specifically to their areas of responsibility. PEPCO (G): Vahos Direct at 16:8-11; PEPCO (G)-2. Company Witness Vahos also discusses the Real Estate and Facilities capital expenditure process and addresses the projects the Company is proposing to undertake. PEPCO (G): Vahos Direct at 44:12-53:11; PEPCO (G)-2.

As Company Witness Leming explained, although Pepco has experienced the same inflationary pressures and supply chain challenges that have had considerable impacts on the global, national, and local economies, the Company has been able to manage its O&M costs.[466] Although the average increase in the Consumer Price Index over the years 2021 and 2022 was 6.7%, Pepco's O&M costs reflect a 3.7% annual growth rate since 2022.[467] Moreover, over the 2023 through 2026 period, the annual growth rate in revenue requirements O&M is 1.9%, significantly below the current rate of inflation.[468]

Although, as discussed further below, DCG Witness Lane suggested that an escalator be used for O&M costs rather than Pepco's cost forecasts, the only specific issue with regard to the Company's projected O&M costs for the MYP period was raised by OPC Witness Gorman, who recommends that the amount of service company charges in the MYP be capped at the 2023 level as he claims Pepco has not provided factual or analytical support for the increases in service company charges from 2022 to the 2023.[469] Company Witness Vahos explained that OPC's assertions are misplaced and should be rejected.

1. The Company's Service Company charges are reasonable.

Company Witness Vahos addressed the increase in service company charges between 2022 and 2023. First, he explained that the service company charges OPC Witness Gorman references are not a true reflection of the overall BSC and PHISCO service company costs, but rather a

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466 PEPCO (B): Leming Direct at 5:19-23.
467 PEPCO (B): Leming Direct at 6:1-2.
468 PEPCO (B): Leming Direct at 6:2-4.
469 OPC (B): Gorman Direct at 31:21-33:2. As a result, he proposes to lower Pepco's District of Columbia Distribution O&M by $1.6 million in 2024, $2.8 million in 2025, and $3.7 million in 2026. *Id*. at 33:6-7.

segmented view of the allocated portion of costs for distribution labor and overtime for Pepco.[470] A better comparison would be the total O&M service company costs for PHISCO and BSC, which include both labor and non-labor charges.[471] With a reasonable estimate of the functionalization of costs to distribution and then to the District, Company Witness Vahos indicates that there was an approximate $7 million increase in service company costs to Pepco DC distribution between 2022 and 2023.[472] OPC Witness Gorman incorrectly suggests that the increase may be attributable to Pepco's excessive and unreasonable inflation assumptions for 2023[473] In reality, the increase includes higher inflation and is driven by critical IT projects as well as changing market conditions.[474]

As Company Witness Vahos explained in discussing the increase in Pepco DC distribution costs between 2022 and 2023, one of the key drivers is an increase in Pension/Other Postretirement Employee Benefit (OPEB) costs in 2023 as a direct result of weak asset performance in the stock market and fixed income sector. This market condition resulted in abnormally higher pension and OPEB costs in 2023 because Pepco does not have pension smoothing accounting.[475]

OPC Witness Gorman also argues that Pepco should provide a full accounting of the allocated service company costs and provide support for the allocation factors used to allocate

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470 PEPCO (3G): Vahos Rebuttal at 7:5-7.
471 PEPCO (3G): Vahos Rebuttal at 7:14-16; PEPCO (3G)-2.
472 PEPCO (3G): Vahos Rebuttal at 7:16-8:9.
473 OPC (B): Gorman Direct at 30:3-4.
474 PEPCO (3G): Vahos Rebuttal at 8:13-15. Company Witness Vahos details the primary IT and other costs driving the increase in service company costs in 2023. *Id*. at 9:3-14.
475 PEPCO (3G): Vahos Rebuttal at 11:7-11.

costs from the service companies.[476] However, as Company Witness Leming explained, in accordance with Rule 3904.1 of the Commission's Affiliate Transactions Code of Conduct,[477] Pepco annually files its Cost Allocation Manual ("CAM") with the Commission, which includes the cost accounting process of the allocations and policies and procedures to accumulate costs of the service companies and methodologies used to assign and allocate costs.[478] Moreover, since the merger with Exelon in March 2016, there have been fourteen separate independent examinations, all of which have found that the allocations and charges were in accordance with the CAM.[479]

OPC Witness Gorman also asserts that Pepco did not detail its inflation outlook for O&M costs over the term of the MYP.[480] Company Witness Vahos explained that at the time the LRP was developed in 2022, the CPI indicated inflation of 6.7%.[481] For purposes of the LRP, Pepco took a more conservative approach than the CPI and assumed labor rate increases for 2023 of 4% and 3% for the 2024-2026 period.[482] Additionally, unless price increases were contractually set,

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476 OPC (B): Gorman Direct at 32:17-20. He also suggests that Pepco recommends that Pepco provide evidence that the service company charges it paid are no more than those that would be charged by an independent third party. Id. at 32:20-33:1. The Company does not complete a comprehensive market study of specific services compared to other independent third parties; however, Company Witness Vahos explained that PHISCO and EBSC adhere to a set of common practices and procedures that ensure the costs incurred are competitive and reasonably priced. PEPCO (3G): Vahos Rebuttal at 4:11-14. Moreover, the annual budgeting process allows PHI to understand as well as help prioritize the work and activities being undertaken by PHISCO and/or EBSC to ensure the services are necessary and cost competitive. *Id*. at 4:22-5:5.

477 15 D.C.M.R. § 3904.1.

478 PEPCO (B): Leming Direct at 73:13-15. *See also* PEPCO (3G): Vahos Rebuttal at 3:18-21. Pepco's then most current 2022 CAM was provided as PEPCO (B)-9. The Company's 2023 CAM was filed with the Commission on April 28, 2023 in PEPCAM2023-01-E and the 2024 CAM was filed on April 30, 2024 in PEPCAM2024-01-E.

479 PEPCO (B): Leming Direct at 73:21-74:10; PEPCO (B)-9. *See also* PEPCO (3G): Vahos Rebuttal at 4:5-7.

480 OPC (B): Gorman Direct at 25:15-16.

481 PEPCO (3G): Vahos Rebuttal at 10:6-7. This represented the average annual price increases between 2021 and 2022, highlighting the inflationary pressure that was present at the time. *Id*. at 10:7-9.

482 PEPCO (3G): Vahos Rebuttal at 10:9-11.

Pepco assumed a non-labor inflation rate of 2.5% for the period 2023 to 2027 – the average of the 2023 to 2027 inflation rate from IHS at the time the LRP was prepared.[483]

Company Witness Vahos explained that IHS data from December 2023 indicated that year-over-year inflation from 2022 to 2023 increased from a forecast of 3.9% at the time the LRP was prepared to 4.1% as of December 2023.[484] Additionally, the 2023-2027 average annual CPI growth rate per IHS increased from 2.5% to 2.7% over this same period which supports that the inflation assumptions used in the LRP are reasonable.[485]

The Company strives to manage overall O&M to be below the rate of inflation. This is illustrated by Pepco DC's distribution O&M compound annual growth rate (CAGR) of 1.9% between 2023 and 2026.[486] Pepco's projections for O&M costs for the term of the MYP are reasonable and should be adopted by the Commission.

2. *Pepco's use of its projected O&M Costs during the MYP is reasonable and is more reflective of the Company's planned spending than the use of an escalator.*

The Company provided detailed information regarding how it projected O&M costs as part of the LRP process and showed that its process is reasonable.[487] The information provided in this proceeding is extensive and affords transparency into the Company's plans throughout the MYP period and establishes that Pepco's revenue requirements are based on its plans that support the

483 PEPCO (3G): Vahos Rebuttal at 10:11-13.
484 PEPCO (3G): Vahos Rebuttal at 10:17-19.
485 PEPCO (3G): Vahos Rebuttal at 10:19-20. Pepco's total year-over-year growth between 2022 and 2023 was 3.3% after adjusting for the higher market driven pension costs, critical IT projects, and normalization of storm costs, which is lower than the 3.9% inflation rate IHS forecast at the time of the LRP as well as the 4.1% as of December 2023. *Id*. at 12:4-13:1 and Table 1. Additionally, Company Witness Vahos noted that, because of emergent and market driven items that contributed to the increase from 2022 to 2023, Pepco DC's O&M distribution compound annual growth rate (CAGR) is 3.7% between 2022 and 2026 but 1.9% between 2023 and 2026. *Id*. at 13:1-7.
486 PEPCO (3G): Vahos Rebuttal at 13:1-3.
487 *See generally* PEPCO (G): Vahos Direct at III (discussing LRP process).

District's goals and policies and continue to provide safe and reliable service to customers.[488] Because the O&M costs included in the MYP are based on the Company's LRP process, they are reflective of Pepco's best current estimates of the planned spending during the MYP's 3-year term.[489] They also consider impacts of inflation and supply chain issues over the 3-year term of the MYP.[490] This approach is therefore better suited for the purpose of setting rates than an escalator as DCG Witness Lane recommends.[491]

DCG Witness Lane's suggests that an escalator should be used as she claims that the reconciliation process, combined with the use of a Company-specific cost forecast, shifts risks to customers.[492] However, this is not the case. The use of Pepco's forecasted costs, provides transparency and the opportunity for alignment between Company plans and the District's goals and policies.[493] Furthermore, under the asymmetric reconciliation structure approved by the Commission in FC 1156 and incorporated into the proposed MYP, there is no incentive for the Company to inflate cost forecasts when, as here, those forecasts are reviewed for reasonableness, actual costs are reviewed for prudency, and over-forecasts accrue carrying costs for the benefit of customers.[494] By contrast, if Pepco were to over-spend its authorized revenue requirement, no carrying costs would apply to any amounts the Commission ultimately approved for recovery.[495]

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488 PEPCO (B): Leming Direct at 9:7-11.
489 PEPCO (B): Leming Direct at 9:14-16.
490 PEPCO (B): Leming Direct at 9:16-17.
491 PEPCO (B): Leming Direct at i.
492 DCG (A): Lane Direct at 22:9-23:3.
493 PEPCO (3B): Leming Rebuttal at 13:19-14:1. Company Witness Leming noted the importance of such alignment given the significant energy transition that will occur in the coming years. *Id*. at 14:1-3.
494 PEPCO (3B): Leming Rebuttal at 13:13-16. Company Witness Leming explained that the reconciliation process adopted in FC 1156 appropriately incentivized the Company to control costs as during the FC 1156 MYP Pepco controlled its O&M costs to be $1.9 million, or 1.2%, lower than the level authorized in 2021, and $3.1 million, or 1.9%, lower than the level authorized in 2022. *Id*. at 14:6-9.
495 PEPCO (3B): Leming Rebuttal at 13:16-17.

Pepco's use of its projected O&M costs during the 3-year term of the MYP is reasonable and should be approved by the Commission.

Q. Pepco's Capital Investments Over a 5-Year Period are Detailed in the Construction Report and Can be Modified to meet DCG's Suggestion for an Integrated Distribution Plan ("IDP")

DCG Witness Lane suggested and DCG reiterated during the Hearing that Commission should not approve an MYP until Pepco develops an IDP.[496] As Company Witness Cantler explains this recommendation ignores that the Construction Report Pepco is required to file is largely inclusive of any IDP as it is required to include all capital investments the Company plans to make for a 5-year period.[497] The Commission has mandated the contents of the Construction Report.[498] Company Witness Cantler detailed the information that is provided in the Construction Report and the enhancements that have been made to provide greater transparency.[499] Moreover, DCG's suggestion ignores that, as the testimony in this proceeding shows, there are differing positions on the Company's grid modernization investments.[500] The wide variety of views on grid modernization suggests that additional collaboration and thought should be considered before any decision is made regarding the need for an IDP.[501]

DCG Witness Lane also claims that the Company must have a separate grid modernization plan to contextualize investments within the MYP.[502] As Company Witness Cantler explains Pepco incorporates grid modernization efforts into its planned investments as normal course of

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496 DCG (A): Lane Direct at 5, 48-50.
497 PEPCO (4H): Cantler Rebuttal at 28:19-23.
498 PEPCO (4H): Cantler Rebuttal at 28:21-22. *See also id*. at 30:12-31:8.
499 PEPCO (4H): Cantler Rebuttal at 29:9-30:9.
500 PEPCO (4H): Cantler Rebuttal at 32:21-33:12.
501 PEPCO (4H): Cantler Rebuttal at 36:3-5.
502 DCG (A): Lane Direct at 48-49.

business.[503] Pepco has provided relevant and significant information to stakeholders through the MYP and its Construction Report, the Company's Annual Consolidated Report ("ACR"), and other venues and forums.[504] For example the ACR provides a comprehensive plan for planned and forward-looking investments that are intended to maintain, design, modernize, and operate the District's distribution system, including a section dedicated to grid modernization.[505]

However, Pepco is continually seeking to improve the usability of the information that it provides to stakeholders. Company Witness Cantler indicated that Pepco would be open to a collaborative process to adapt the grid modernization section of its ACR to better meet the informational needs of stakeholders related to the Company's grid modernization plans.[506] More recently, the Company indicated in its Reply Comments on the Value of Distributed Energy Resources ("VDER Reply Comments") filed on July 30, 2024 in FC 1130, that:

> Pepco is already required to provide information through regulatory filings and through public facing maps that largely align with the goals of [Integrated Distribution System Plan]s. For example, Pepco's Annual Consolidated Report ("ACR"), published annually in April, includes a comprehensive plan for planned and forward-looking investments that are intended to maintain, design, modernize, and operate the District's distribution system. In addition, with each rate case filed by the Company, Pepco files a Construction Report ("CR") that discusses all the investments the Company is seeking approval of in a rate case as well as other projects planned in a five-year budgeting timeframe. This report also includes much of the planning information included in the ACR. However, much of the content and layout of the information the Commission requires for the ACR and CR are dated, with the CR requirements going back to Formal Case No. 1087 in 2012 and certain ACR directives stemming from orders in the 1980s. Given the tenor of the comments in this proceeding and the forums created by Pepco's annual ACR and rate case CR filings, Pepco welcomes stakeholder feedback on updating and enhancing the content of these reports through a Commission-endorsed and -facilitated working group process. This forum can facilitate broader discussions

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503 PEPCO (4H): Cantler Rebuttal at 34:6-35:10.
504 PEPCO (4H): Cantler Rebuttal at 32:6-8.
505 PEPCO (4H): Cantler Rebuttal at 32:8-9.
506 PEPCO (4H): Cantler Rebuttal at 32:14-16.

> regarding distribution system planning while also allowing for discussion when information must be confidential for security purposes. A working group has the benefit of improving the reporting process for interested District stakeholders. The Commission should consider this to efficiently facilitate discussion, avoid redundancies, and streamline content in existing reporting to relevant information that is important to stakeholders and the Commission.[507]

The Commission should adopt Pepco's suggestion and establish such a working group to examine this matter and make recommendations.

R. The Commission Should Approve the Company's Tax Proposals.

Pepco's direct testimony also included several proposals related to taxes, including the inclusion of the newly enacted Corporate Alternative Minimum Tax ("CAMT") in rate base, the Income Tax Adjustment Rider ("ITA Rider") to account for potential changes to state and federal taxes, and a proposal to recover PHISCO's non-property Deficient Deferred Income Taxes ("DDIT").[508] No parties directly challenged the inclusion of CAMT in rate base. While OPC challenged Pepco's proposal related to DDIT,[509] in its Rebuttal Testimony, the Company explained why its request to include DDIT in customer rates is reasonable given that the underlying costs giving rise to PHISCO's non-property related DDIT are included in customer rates.[510]

As part of the MYP, Pepco proposed an Income Tax Adjustment Rider ("ITA") for the purpose of recovering or refunding the revenue requirement associated with federal or District of Columbia statutory corporate income tax rate changes, including implementation of a corporate

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507 VDER Reply Comments at pp. 3-4.
508 PEPCO(B): Leming Direct at 57 – 59:18.
509 OPC(D): Gorman Direct at 34:10 to 37:7.
510 PEPCO (3B): Leming Rebuttal at 25:13-26:13.

alternative minimum tax, that are enacted between base rate cases.[511] As Company Witness Leming explained, Pepco is not requesting approval to implement specific new electric ITA Rider rates but rather is requesting approval of the ITA Rider as a mechanism to timely address future corporate income tax legislation changes.[512] Such changes are beyond the control of the Company and customers and the ITA provides a near real-time mechanism to adjust for changes in statutory income tax rates that arise in between Pepco's base rate cases.[513]

Company Witness Bonikowski detailed the mechanics of the proposed ITA.[514] The ITA would become effective on ten calendar days' notice, or as soon as practicable, following the effective date of a change in the statutory tax rate.[515] Once triggered, the ITA would then be filed with the Commission annually in November establishing rates to be included in the Distribution Charge on bills effective with January billings.[516] An annual reconciliation for the ITA would be filed with the Commission in March for the 12 months ended December 31 of the prior year and any applicable reconciliation component added to Rider ITA rates and assessed from May through December.[517] The ITA would remain in place until the Commission approves new base rates that include the effects of the tax rate change at issue.[518]

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511 PEPCO (E): Bonikowski Direct at 67:13-17. As Company Witness Bonikowski explained, although a tax rate change impacts the required level of revenue for surcharge mechanisms, surcharge mechanisms can already address tax rate changes in a timelier manner than base rates and therefore the proposed ITA addresses only base distribution rates. Id. at 68:3-6.

512 PEPCO (B): Leming Direct at 24:22-25:4.

513 PEPCO (B): Leming Direct at 25:6-16. Company Witness Leming indicated that, although proposed in the MYP, the ITA would be equally applicable to traditional rate case filings when the cadence of periodic cases does not align with the timing of an income tax rate change. Id. at 25 14-16. The ITA Rider was subsequently included in the TTYCF. PEPCO (2E): Bonikowski Supp. Direct at IX.

514 PEPCO (E): Bonikowski Direct at 68:6-18.

515 PEPCO (E): Bonikowski Direct at 68:6-8.

516 PEPCO (E): Bonikowski Direct at 68:9-11.

517 PEPCO (E): Bonikowski Direct at 68:11-14.

518 PEPCO (E): Bonikowski Direct at 68:15-16. When the ITA concludes, a final reconciliation will be prepared and a final refund or surcharge, as applicable, will be determined. Id. at 16-18.

No party objected to Pepco's Rider ITA. The Commission should approve Rider ITA as a reasonable mechanism to timely address future corporate income tax legislation changes.

S. PEPCO'S Proposed New Time-of-Use Rate Offerings Are Reasonable.

The Company is proposing to introduce two new opt-in rate offerings to enhance customer choice, support the District's climate objectives, and promote customer affordability: (1) a residential time-of-use (TOU) rate (Schedule R TOU), and (2) TOU electric vehicle charging rates for demand-metered commercial rate schedules.[519]

1. Schedule R TOU.

Pepco's Schedule R TOU rate would include distribution, generation, and transmission TOU rates to all Residential customers on an opt-in basis.[520] The proposed rate is designed to incentivize Residential customers to shift energy consumption to off-peak periods when the distribution system is less constrained.[521] In addition to increasing customer optionality, the proposed rate offering would promote affordability by enabling customers who are able to shift or reduce energy loads during on-peak periods to realize bill savings.[522]

Schedule R TOU consists of a fixed distribution customer charge, equal to the proposed Schedule R customer charge in each rate year, and seasonal on-peak and off-peak distribution

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519 *See generally* PEPCO (E): Bonikowski Direct at V. These new rate offerings were also included in Pepco's TTYCF. *See generally* PEPCO (2E): Bonikowski Supp. Direct at VI.
520 PEPCO (E): Bonikowski Direct at 42:14-15.
521 PEPCO (E): Bonikowski Direct at 43:14-16.
522 PEPCO (E): Bonikowski Direct at 43:16-22.

energy charges.[523] The proposed generation rate structure similarly features seasonal on-peak and off-peak energy charges, while transmission rates consist solely of an on-peak energy charge.[524]

Approval of this new rate schedule will obviate the need for the existing Schedule R-PIV rate.[525] Therefore, if approved by the Commission, the Company would close Schedule R-PIV new customer enrollment and migrate currently enrolled customers to either Schedule R or the new Residential TOU rate schedule, at the customer's election.[526] Implementation of Schedule R TOU would require some time so, if approved, Pepco will submit an implementation plan to the Commission defining the implementation timeline.[527] No party objected to Pepco's proposed Schedule R TOU.

2. Commercial EV TOU Program.

The commercial TOU electric vehicle charging rates are designed to be a flexible solution for a variety of commercial and fleet charging applications, including transit bus fleets, and encourage fleet owners to shift vehicle charging to late evening and early morning hours when feeder capacity is generally less constrained.[528] As Company Witness Bonikowski explained this both reduces the likelihood that significant distribution system upgrades may be required to

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[523] The proposed on-peak and off-peak periods were selected based predominantly on an analysis of Residential class hourly peak load data for calendar years 2017 through 2021, developed by summarizing the hourly AMI data for the Residential class for all hours of each year. PEPCO (E): Bonikowski Direct at 44:17-20; PEPCO (E)-12. The results of this analysis show that the Residential class peak consistently falls within the Company's proposed peak window of 5:00 p.m. to 10:00 p.m. *Id*. at 44:20-45:2; PEPCO (E)-12. Company Witness Bonikowski also detailed the methodology Pepco used to allocate distribution costs between on-peak and off-peak periods and then converted into rates. *Id*. at 45:5-46:15.

[524] PEPCO (E): Bonikowski Direct at 46:18-22. Unlike Schedule R, the proposed Schedule R TOU does not provide blocked distribution energy charges or blocked SOS charges as this could lead to customer confusion. *Id*. at 46:22-47:4.

[525] PEPCO (E): Bonikowski Direct at 48:15-16. Company Witness Bonikowski discussed the advantages that the proposed Schedule R TOU would provide over Schedule R-PIV. *Id*. at 47:12-48:15.

[526] PEPCO (E): Bonikowski Direct at 48:15-22.

[527] PEPCO (E): Bonikowski Direct at 49:3-6.

[528] PEPCO (2E): Bonikowski Supp. Direct at 22:1-4.

accommodate new EV charging load and also promotes customer affordability by providing an opportunity for customers to realize bill savings if they are able to shift or reduce load during on-peak hours, improving the economics of fleet electrification.[529]

The Company is proposing new opt-in commercial TOU rates for separately metered electric vehicle charging for each of its demand-metered customer classes, except Schedule GT 3B, i.e. Schedule GS LV EV, MGT LV EV, GT LV EV, GS 3A EV, and GT 3A EV.[530] Each of these proposed rates offers TOU generation, transmission, and distribution rates.[531] On-peak hours for each rate schedule are defined as 6:00 a.m. to 8:00 p.m. in both summer and winter, Monday through Friday, excluding Federal holidays.[532] The rate schedules will be available for electric service used solely for separately metered electric vehicle battery charging purposes, as well as ancillary load directly related to the provision of electric vehicle charging, such as area lighting.[533] Each commercial EV TOU rate schedule is designed to be revenue neutral as compared to the corresponding reference rate schedule, based on the reference rate schedule's historic load profile and billing determinant forecast.[534] Implementation of the commercial TOU electric vehicle charging rates would require some time so, if approved the rates are approved by the Commission,

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529 PEPCO (E): Bonikowski Direct at 49:13-19.
530 PEPCO (E): Bonikowski Direct at 49:10-13.
531 The proposed rates include three distribution charge types: a customer charge; an energy charge; and a demand charge. Company Witness Bonikowski described these charge types. PEPCO (E): Bonikowski Direct at 52:13-53:13.
532 PEPCO (E): Bonikowski Direct at 49:20-50:2. Company Witness Bonikowski indicated that the on-peak and off-peak hours for the proposed commercial TOU rate schedules were selected by evaluating the hourly distribution feeder loads across its system from 2019 and 2020 (*Id*. at 52:2-6; PEPCO (E)-11) as well as individual class load curves for each of the applicable rate schedules for calendar years 2017 through 2021. *Id*. at 52:7-10; PEPCO (E)-12. Pepco is proposing a 2:1 on-peak to off-peak price ratio for all distribution, generation, and transmission energy and demand charges. *Id*. at 53:16-20. Company Witness Bonikowski addressed how the proposed ratio was developed. Id. at 54:3-55:8 and Tables 5 & 6.
533 PEPCO (E): Bonikowski Direct at 50:5-8. The schedules will apply to Level 1, Level 2, and Direct Current Fast Charging (DCFC) EV chargers provided the aggregated load requirements of the charging equipment meet the load requirements to be eligible for a given rate schedule. *Id*. at 50:8-10.
534 PEPCO (E): Bonikowski Direct at 51:3-5.

Pepco will submit an implementation plan to the Commission defining the implementation timeline.[535]

Although AOBA summarily indicated that it did not support Pepco's proposed commercial EV TOU rates claiming they would add complexity to the ratemaking process,[536] AOBA Witness B. Oliver did not address the benefits Company Witness Bonikowski explained the TOU rate would provide to customers.

The Commission should approve both Schedule R TOU as well as the Commercial EV TOU Program as reasonable and direct Pepco to file an implementation plan for each of these new rate schedules.

T. Pepco's Lead-Lag Study and Proposed Cash Working Capital Allowance Are Reasonable.

Pepco conducted a new lead-lag study for this proceeding based on calendar year 2021 data.[537] The Company's lead-lag study uses the same methodology as the study that the Commission approved in FC 1139 and was the basis of the cash working capital adjustment in FC 1156.[538] Pepco's lead-lag study indicated higher revenue lags in several categories that were determined to be largely driven by slowed customer payment activity and growing receivable balances, which are likely the result of ongoing impacts of the COVID-19 pandemic as well as inflationary pressures.[539] Pepco reviewed the underlying collection data to confirm that there were no unusual or one-time events included that inflated lag day results.[540] Additionally, the Company

535 PEPCO (E): Bonikowski Direct at 56:3-6.
536 AOBA (A): B. Oliver Direct at 116:21-117:4.
537 PEPCO (C): Holden Direct at 22:14-16; PEPCO (C)-4.
538 PEPCO (C): Holden Direct at 22:16-18. FC 1139, Order No. 18846 at ¶42; FC 1156, Order No. 20755 at ¶257.
539 PEPCO (C): Holden Direct at 23:2-8.
540 PEPCO (C): Holden Direct at 23:8-10.

reviewed customer receivable balances as of December 31, 2022 and confirmed that there had not been a significant change indicative of increased speed of payment.[541] Company Witness Holden indicated that the lead-lag study provides a reasonable basis for the calculation of the Company's proposed CWC allowance for the MYP.[542]

The only party to contest Pepco's lead-lag study was AOBA. AOBA Witness B. Oliver argued that Pepco's lead-lag study was heavily influenced by the effects of the COVID-19 pandemic and suggested that the study therefore be rejected and the 2017 lead-lag study from FC 1156 remain in place.[543] AOBA's concerns are misplaced, unsubstantiated and should be rejected.

Beyond noting an overall increase in the composite revenue lag between the 2021 and 2017 lead-lag studies, AOBA Witness B. Oliver does not provide any specific support or quantification of the magnitude of pandemic-related impacts on the noted increase in revenue lag days.[544] Similarly he provided no tangible evidence that the revenue lag trend has improved or significantly differs from the results reflected in Pepco's 2021 lead-lag study.[545] Moreover his suggestion to continue to use the 2017 lead-lag study is inappropriate. The data used in that earlier study would be 7 years old when rates go into effect in this proceeding.[546] Pepco's lead-lag study that is based on more recent data from 2021 better reflects the payment and cash receipt trends the Company is

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541 PEPCO (C): Holden Direct at 23:11-13.

542 PEPCO (C): Holden Direct at 23:13-15. In FC 929, the Commission indicated that "lead and lag days for individual accounts do not normally change in a material manner over a two- or three-year period." FC 929, Order No. 10387 at 65; FC 939, Order No. 10646 at 61. The TTYCF used the same lead-lag study as the MYP. PEPCO (2B): Leming Supp. Direct at 28:18-20.

543 AOBA (A): B. Oliver Direct at 80:17-81:12.

544 PEPCO (2C): Holden Rebuttal at 7:9-11.

545 PEPCO (2C): Holden Rebuttal at 7:12-14.

546 PEPCO (2C): Holden Rebuttal at 8:5-6.

experiencing – this is especially so given the lack of evidence of any material changes in trends of lead and lag days.[547]

Company Witness Holden also explained that it would be inappropriate to adjust the results of Pepco's 2021 lead-lag study for any impacts of the COVID-19 pandemic as any such impacts are not discrete, isolatable impacts that allow for adjustment.[548] Moreover, the Company has not observed any evidence that the results of its 2021 lead-lag study represent an anomaly, or that the results are not indicative of current customer payment behaviors and trends.[549] To the contrary, Pepco has observed that its District customer accounts receivable balance has continued to grow since 2021, which is indicative of a sustained increase in the revenue lag as reflected in the 2021 lead-lag study.[550] Pepco's 2021 lead-lag study takes into account more recent and relevant market conditions, providing a better reflection of both the current and future economic conditions impacting customer payment trends than the 2017 lead-lag study AOBA recommends should continue to be used.[551]

Finally, Company Witness Holden noted that the Commission rejected similar arguments by AOBA in WGL's most recent base rate case, FC 1169.[552] In that proceeding, WGL proposed a CWC balance based on a lead-lag study that used 2021 data. AOBA argued that the revenue lags should be adjusted to account for the impacts of COVID-19 on customer payment practices. Like this proceeding, in FC 1169, the payment practices WGL observed throughout the proceeding

547 PEPCO (2C): Holden Rebuttal at 8:7-11.
548 PEPCO (2C): Holden Rebuttal at 8:14-16, 9:9-12; PEPCO (C): Holden Direct at 23:8-10.
549 PEPCO (2C): Holden Rebuttal at 8:16-18; PEPCO (C): Holden Direct at 23:10-13.
550 PEPCO (2C): Holden Rebuttal at 9:1-8. Data demonstrating these trends was provided in Pepco's response to AOBA DR 2-20.
551 PEPCO (2C): Holden Rebuttal at 9:13-16.
552 PEPCO (2C): Holden Rebuttal at 9:19-10:9.

were consistent with the lead-lag study results developed using 2021 data. In Order No. 21939, the Commission found that WGL's methodology in calculating CWC was consistent with Commission precedent and denied AOBA's proposed pandemic-related adjustments due to insufficient documentation indicating WGL's revenue lag trend had materially changed.[553] Pepco's lead -lag study using 2021 data is reasonable and should be accepted for use in this proceeding.

The revenue and expense lag factors from the lead-lag study were applied to the test year operating results to derive Pepco's proposed unadjusted CWC allowance.[554] The CWC allowance was then adjusted to reflect the impact of the Company's RMAs.[555] Pepco's CWC allowance is reasonable and should be accepted.[556]

U. Pepco's Forecasts of Billing Determinants Are Reasonable.

Company Witness Efimova addressed in detail the methods and forecasts of billing determinants used in developing the MYP and showed them to be reasonable and consistent with accepted utility practice.[557] Pepco uses knowledge of economics, econometrics, understanding of electricity consumption, professional forecasting experience, and sophisticated models to develop forecasts of three types of billing determinants for the MYP: energy sales, number of customers,

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553 FC 1169, Order No. 21939 at ¶149.

554 PEPCO (C): Holden Direct at 23:17-21; PEPCO (C)-1, pages 14,18.

555 PEPCO (C)-1, pages 15-16. Other parties have proposed changes to some of the Company's RMAs and new adjustments to test year expenses. If any of these adjustments are accepted, it would impact the calculation of the adjusted test year CWC allowance.

556 Noting that, in FC 1103, the Commission held that, "going forward, the Company's final CWC adjustment will be calculated to reflect the level of revenue and operating expenses approved in the rate proceeding." FC 1103, Order No. 17424 at ¶33.

557 *See generally*, PEPCO (K): Efimova Direct. Company Witness Efimova provided a general overview of Pepco's modeling and forecasting in her Direct Testimony while more technical information behind the Company's forecasting, econometric detail, and results with descriptions are provided in the written forecast documentation and accompanying exhibits was included as PEPCO (K)-1 through PEPCO (K)-52.

and billing demand.[558] The information developed is used to inform the rate design process for the MYP.[559]

Company Witness Efimova explained that Pepco follows a consistent and standard process to estimate its forecasting models.[560] The goal is to develop the final model that is reasonable considering each tariff class's data input. To achieve this, the Company evaluates model performance using a measure of prediction accuracy and follows empirical rules generally used in statistics.[561] The choices also reflect a forecaster's judgments based on each tariff model case. Pepco attempts to find the best model specification with the most reasonable performance using actual data inputs.[562] The Company also ensures that empirical choices do not go against theoretical assumptions and that models fit the data well to estimate driver relationships based on statistical testing of regressions.[563]

To assist parties' evaluatation of the billing determinants forecast and its reasonableness, Pepco developed a Sensitivity Calculator, a new analysis that provides parties without access or the ability to run the regression models with an innovative tool built in Excel.[564] The Sensitivity Calculator allows parties to understand how the model works based on major sales driver inputs

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558 PEPCO (K): Efimova Direct at 5:7-12.

559 PEPCO (K): Efimova Direct at 5:16-17.

560 PEPCO (K): Efimova Direct at 11:14-15. With the importance of forecasting for setting future rates, the Company enhanced its forecasting process, engaging Itron to evaluate prior forecasting methods in the context of rate design and completely rebuilding its modeling structure for use in the MYP filing setting by making sure it is within industry practices following Itron's recommendations. *Id*. at 27:14-20. Among the enhancements Pepco made to its billing determinants forecasting approach was to provide greater forecast granularity at the tariff-class level. The new models also added additional economic, EE, COVID-19, and enhanced weather spline variables to align closer to industry practices. *Id*. at 28:4-12.

561 PEPCO (K): Efimova Direct at 11:15-19.

562 PEPCO (K): Efimova Direct at 11:19-12:2: PEPCO (K)-10.

563 PEPCO (K): Efimova Direct at 12:2-4.

564 PEPCO (K): Efimova Direct at 24:6-11;

and also permits them to create their own forecast changes by alternating the levels of key driver variables. The Company also provided an analysis of potential future "sensitivities." Pepco also held a technical conference on May 23, 2023,[565] to discuss its forecasts of billing determinants used in developing the MYP and to allow parties to ask questions.

The only party to directly challenge Pepco's billing determinants forecast was OPC. OPC Witness Gorman asserts that the Company included factors in its billing determinants forecasts that reduce forecasted residential usage, such as energy efficiency, but excludes factors which may increase it, such as electrification, thus, producing what he claims is an "unbalanced" forecast.[566] He recommends that the Commission should find Pepco's forecast of residential Usage per Customer (UPC) to be understated and impose a constant UPC holding it at 636 kWh per customer per month, the forecasted levels, throughout the MYP period.[567] Company Witness Efimova explains that OPC's proposal arbitrarily raises the energy sales forecasts for residential customers and should be rejected.[568]

Contrary to OPC's claims, Pepco uses various drivers in the forecasting of billing determinants, including drivers that increase residential UPC.[569] Some impacts of building electrification were implicitly incorporated through historical usage data entering the regression

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565 A copy of Pepco's Billing Determinants Forecast presentation at the technical conference was provided as PEPCO (2K)-2.

566 OPC (B): Gorman Direct at 7:16-19; 11:4-6.

567 OPC (B) Gorman Direct at 17:2-3. OPC Witness Gorman claims that his proposal is more reasonable and balanced because the Company has the protection of the MYP reconciliation process to ensure it recovers its cost of service in case future actual sales differ from the forecast; however, as Company Witness Efimova emphasizes neither customers nor Pepco benefit from inaccurately set rates. PEPCO (2K): Efimova Rebuttal at 14:6-7.

568 PEPCO (2K): Efimova Rebuttal at ii.

569 PEPCO (2K): Efimova Rebuttal at 5:14-6:5. For example, as Company Witness Efimova described in her Direct Testimony, Pepco accounts for the impact of anticipated electrification in the form of EV adoption through an out-of-model adjustment because the impact on sales of EV adoption historically has been very small and the regression models do not recognize its impact well. PEPCO (K): Efimova Direct at 9:15-19.

models. OPC Witness Gorman also incorrectly points to the distribution planning forecast assumptions and billing determinant assumptions in Pepco's response to AOBA DR 1-11 and improperly concludes that this provides evidence the billing determinants forecast is "imbalanced.[570] It does not. The differences between billing determinants forecasts and capacity/load forecasts were addressed by Company Witness Cantler in her Supplemental Direct Testimony.[571]

Similarly, OPC Witness Gorman's assertion that the Company excludes conversion to electrification in its billing determinants forecast is incorrect.[572] Company Witness Efimova's Direct Testimony actually indicated that existing building electrification impacts are accounted for through existing trends.[573] The impact of building electrification is implicitly captured in Pepco's forecast through historical sales data in the regression models.[574] Because of this, OPC's assumption would be double counting the sources of growth in the forecast.[575]

Moreover, the actual impact of building electrification on residential sales over the next several years and beyond is far from certain and not precise enough to include in the current billing determinants forecasts.[576] Company Witness Efimova cautioned that there is a lack of clarity about

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570 OPC (B): Gorman Direct at 14:3-28.

571 PEPCO (3H): Cantler Supp. Direct at 8:17 - 9:2.

572 OPC (B): Gorman Direct at 11:9-12.

573 PEPCO (2K): Efimova Rebuttal at 6:11-14.

574 PEPCO (2K): Efimova Rebuttal at 6:14-19. Company Witness Efimova indicated that once the impacts of policies related to electrification can be better discerned, Pepco will evaluate and incorporate those into its future MYP billing determinants forecasts. *Id*. at 6:19-21.

575 PEPCO (2K): Efimova Rebuttal at 12:5-6.

576 PEPCO (2K): Efimova Rebuttal at 7:4-6.

specific impacts of building electrification and decarbonization goals on residential customer bills and certainly no proof that they will lead to flat residential UPC over the MYP period.[577]

Finally, OPC Witness Gorman provides no analysis that quantifies the impacts of building electrification on residential UPC to justify his UPC assumption[578] and he does not provide sufficient support to demonstrate that his recommendation produces a more reasonable forecast than Pepco's. His recommendation that the residential UPC be held flat at 636 kWh per customer per month over the MYP period is not supported by the data. Looking back ten years, residential UPC has been continuously declining and is projected to continue to decline into and during the MYP period.[579] OPC Witness Gorman essentially assumes that the impacts of building electrification and/or other unquantified upside will completely offset growing impacts of energy efficiency[580] (and DER) but, unlike the extensive and rigorous forecast documentation Pepco provided for its billing determinants forecast, OPC does not provide adequate support to demonstrate that holding 2023 forecasted levels of residential UPC constant is a reasonable and an appropriate assumption to use for the MYP period.[581]

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[577] PEPCO (2K): Efimova Rebuttal at 8:2-5. She also noted that energy efficiency will provide an offsetting impact to building electrification-related increases in residential electric usage. *Id*. at 8:8-9.

[578] Pepco Data Request No. 1 to OPC asked OPC to provide all relevant workpapers and analysis OPC Witness Gorman used to derive his recommendation; however, OPC's response does not provide additional information to explain the choice of holding residential UPC flat.

[579] PEPCO (2K): Efimova Rebuttal at 9:10-11:1.

[580] OPC Witness Gorman claims that there is uncertainty regarding future energy efficiency programs that were included in Pepco's billing determinants forecast. OPC (B): Gorman Direct at 12:14-15. The forecast included savings based on DC SEU as well as Company programs based on the information available at the time the forecast was prepared and was reasonable. It reflects the annual energy savings goal the Commission established in Order No. 20654 for utility-run EE programs. Given the importance of EE in meeting District climate goals, it is reasonable to expect that the savings from the identified EE programs should be achieved through Commission approved programs or programs implemented by others. PEPCO (2K): Efimova Rebuttal at 12:17-13:20.

[581] PEPCO (2K): Efimova Rebuttal at 11:8-12:4. Pepco does seek continuous improvement of its billing determinants forecasting. While OPC Witness Gorman's recommendations are not appropriate for this proceeding, building electrification is an important subject to evaluate for the Company's next MYP.

Pepco's forecast of residential UPC is reasonable and should be accepted by the Commission for this current MYP. Moreover, the Company provided extensive documentation, supporting data/exhibits, held a technical conference, and undertook a careful evaluation of the impacts of various assumptions on billing determinants. Pepco also documented, rigorously evaluated, and incorporated assumptions consistent with utility practices and industry standards as detailed in the testimony of Company Witness Efimova. Pepco's billing determinants forecasts are reasonable and their use in this proceeding should be approved by the Commission.

V. Pepco's Jurisdictional Cost of Service Study ("JCOS") Is Consistent with Commission Precedent, Is Reasonable and Should Be Approved.

The JCOS for the MYP, which was presented in PEPCO (B)-3, assigns and allocates each element of Pepco's unadjusted rate base, revenues, and expenses to the Company's Pepco District of Columbia jurisdiction for 2022, the projection of distribution costs for the bridge year 2023, as well as each of the MYP's projected years 2024, 2025 and 2026.[582] As Company Witness Leming explained, the methodologies the Company used are reasonable and consistent with those the Commission has previously approved and, therefore, should be approved.[583]

The Company developed the JCOS to appropriately assign and allocate each element of rate base, revenues, and expenses to Pepco's District of Columbia jurisdiction.[584] The costs associated with customers outside of the District of Columbia are assigned and allocated to the "Other" jurisdiction.[585] The allocations and assignments in the JCOS are consistent with the study

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[582] PEPCO (B): Leming Direct at 44:2-11.
[583] PEPCO (B): Leming Direct at 44:2-46:19; PEPCO (B)-3.
[584] PEPCO (B): Leming Direct at 44:2-4.
[585] PEPCO (B): Leming Direct at 44:4-5.

that the Commission found reasonable in FC 1156.[586] The study's allocations were driven primarily by direct jurisdictional assignments and allocations of plant, depreciation expense, and O&M expense.[587]

Pepco projected and directly assigned the amount of plant additions for Pepco District of Columbia Distribution EPIS, as opposed to allocating "Total Pepco" distribution plant additions to the District of Columbia based on an allocation ratio. The projected EPIS by FERC account was developed by pro-rating the projected plant additions to the FERC accounts based on historical plant additions activity for the previous year.[588]

The majority of Pepco's distribution facilities are primary- and secondary-voltage systems (*e.g.*, distribution substations, overhead and underground lines, and line transformers), which serve customers in a local area and were, therefore, directly assigned to the appropriate jurisdiction.[589] Similarly, consistent with well-established Commission precedent, subtransmission facilities were allocated according to the Average and Excess Demand Non-Coincident Peak ("AED-NCP") method.[590]

Consistent with the method approved in prior proceedings, distribution-general and intangible plant was allocated to jurisdiction based on the subtransmission and distribution plant, less allowance for funds used during construction ("AFUDC") ratios.[591] Distribution and general

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586 PEPCO (B): Leming Direct at 44:5-7. *See* FC 1156, Order No. 20755 at ¶366.
587 PEPCO (B): Leming Direct at 44:7-9.
588 PEPCO (B): Leming Direct at 44:12-22.
589 PEPCO (B): Leming Direct at 45:1-4.
590 PEPCO (B): Leming Direct at 45:5-11. *See* FC 1156, Order No. 20755 at ¶366; FC 1139, Order No. 18846 at ¶399; FC 1103, Order No. 17424 at ¶384; FC 1087, Order No. 16930 at ¶268; FC 1076, Order No. 15710 at ¶288; FC 1053, Order No. 14712 at ¶¶254-56.
591 PEPCO (B): Leming Direct at 45:12-15. *See* FC 1156, Order No. 20755 at ¶366; FC 1139, Order No. 18846 at ¶399.

depreciation expenses were assigned to the appropriate jurisdiction based on Company plant-related records.[592]

Distribution O&M expenses were assigned based on detailed direct assignments where applicable or allocated at the FERC account level using relevant plant ratios based on 2022.[593] Incremental storm and tree trimming costs are separately identified in the JCOS and are assigned to a jurisdiction based upon the Company's records.[594] Customer accounts and sales expense (FERC Accounts 901 through 913) were assigned to a customer class based on the results of the Company's most recent detailed analysis of these accounts and then allocated to jurisdictions based on the number of customers in 2022.[595]

The majority of administrative and general ("A&G") expenses were allocated based on the O&M expense less A&G, storm, and tree trimming allocator; however, property insurance (FERC Account 924) was allocated on subtransmission and distribution plant, and regulatory expenses (FERC Account 928) were directly assigned to the jurisdiction.[596]

All of the allocation methods used in the Company's JCOS have previously been approved by the Commission and were used in the JCOS approved in FC 1156.[597]

No party objected to the Company's JCOS. The Commission should find that the JCOS is reasonable and consistent with Commission precedent.

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592 PEPCO (B): Leming Direct at 45:17-21.
593 PEPCO (B): Leming Direct at 46:2-5.
594 PEPCO (B): Leming Direct at 46:5-6.
595 PEPCO (B): Leming Direct at 46:7-10.
596 PEPCO (B): Leming Direct at 46:11-16.
597 PEPCO (B): Leming Direct at 46:17-19.

W. Pepco's Customer Class Cost of Service Study Is Reasonable and Should Be Approved.

Pepco has established that its customer class cost of service study ("CCOSS") is reasonable and should be approved. Company Witness Gardiner presented the CCOSS, which was developed to assign and allocate Pepco's rate base, revenues, and expenses to customer classes based on the principle of cost causation.[598] The CCOSS is based on the 12-month period ending December 31, 2021 and provides both a reasonable representation of each of the Company's rate class's contribution to Pepco's revenue requirement and a calculation of unit costs.[599]

The CCOSS, which is similar to those the Company used in prior proceedings,[600] informs the rate design for the MYP Proposal.[601] The CCOSS incorporates the unadjusted results of the JCOS and includes the applicable ratemaking adjustments as shown in the Company's FC 1156 Annual Informational Filing for CY 2021 in order to provide a more accurate portrayal of the cost of service for each customer class.[602]

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598 PEPCO (D): Gardiner Direct at 3:4-6. In addition to the CCOSS, which was provided as PEPCO (D)-1, Company Witness Gardiner also provided: CCOSS Summary of Results (PEPCO (D)-2); CCOSS Summary of Allocators (PEPCO (D)-3); Unbundled Cost, Revenue (PEPCO (D)-4); Unbundled Cost, Unit (PEPCO (D)-5); and CIAC Workpaper (PEPCO (D)-6).

599 PEPCO (D): Gardiner Direct at 5:5-8.

600 Company Witness Gardiner detailed the modifications made to update the CCOSS in the following areas, including a comparison showing the impact of each change as well as the overall impact by rate class: functionalization of distribution and sub-transmission AFUDC; primary/secondary split functionalization; surcharge allocation; development of demand allocators; and meter allocation. PEPCO (D): Gardiner Direct at 6:4-14 (Table 5).

601 PEPCO (D): Gardiner Direct at 5:10-11.

602 PEPCO (D): Gardiner Direct at 5:21-6:3.

The only party to challenge the Company's CCOSS was AOBA. Company Witness Gardiner addressed each of the concerns raised be AOBA Witness B. Oliver and showed that they were not a basis to reject the CCOSS.[603]

AOBA Witness B. Oliver inaccurately claimed that the CCOSS model lacks transparency because of the presence of hardcoded values.[604] However, as Company Witness Gardiner explained and was also indicated in Pepco's response to AOBA DR 6-2, the calculation of any hardcoded value in the CCOSS model can be found in the "sub(functions)" worksheet that was provided.[605]

AOBA Witness B. Oliver asserts that PEPCO (D)-2 should reconcile with the customer unit costs in PEPCO (E)-4.[606] However, this is not the case. Company Witness Bonikowski relied on customer unit costs at the proposed rate of return presented in PEPCO (D)-4, not on the customer unit costs at the present rate of return presented in PEPCO (D)-2. The customer unit costs in PEPCO (D)-4 and PEPCO (E)-4 do in fact match.[607]

Although AOBA Witness B. Oliver agrees that Contributions in Aid of Construction ("CIAC") should not be a part of rate base,[608] he argues that CIAC should be included separately,

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603 To address some of AOBA's concerns and facilitate its review of the CCOSS, Company Witness Gardiner agreed to provide CCOSS analyses comparable to those in FC 1156, to remove the proprietary label from the CCOSS model; and to provide a table of contents in the electronic-only version of the CCOSS model. PEPCO (2D): Gardiner Rebuttal at 2:15-3:18. Additionally, Pepco agreed with AOBA's recommendation to calculate a per-customer average Customer Installations (Account 371) unbundled cost for Schedules GT-LV and MGT-LV, effectively setting this cost equal for all customers in both classes. *Id*. at 6:8-9; PEPCO (2D)-1. The Company also indicated that it would review Customer Installations (Account 371) unbundled costs and provide a recommendation in the Company's next base rate case, *Id*. at 6:16-18.

604 AOBA (A): B. Oliver Direct at 87:13-17.

605 PEPCO (2D): Gardiner Rebuttal at 4:8-20.

606 AOBA (A): B. Oliver Direct at 90 n.70.

607 PEPCO (2D): Gardiner Rebuttal at 5:3-11.

608 AOBA (A): B. Oliver Direct at 99:14-15.

not netted, in the CCOSS model. He claims that CIAC payments are not proportional to rate base allocations, and as a result, large commercial customers should bear less responsibility for customer-related facilities costs.[609] Contrary to AOBA's claims, CIAC amounts are not a part of rate base and have no relevance in the determination of rate base allocations and customer unit costs.[610] As such, its inclusion would distort the results of the CCOSS model.[611]

AOBA Witness B. Oliver suggests that Pepco should be required to provide a CCOSS model for each year of an MYP,[612] as he claims there is not uniform growth in cost categories, and as a result, the change in cost responsibilities should be reflected in the revenue allocation determinations.[613] AOBA's suggestion ignores that the CCOSS represents a snapshot of time and is used as a guide in rate design.[614] As Company Witness Gardiner indicated, the use of an historical CCOSS throughout an MYP has been accepted not only in FC 1156 but also in several MYPs in Maryland.[615] Additionally, the Company does not forecast demand and customer expense accounts at the rate class level, and as a result, would need to rely on historical test-year allocators and thus an historical CCOSS remains the most appropriate guide for rate design throughout an MYP.[616]

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609 AOBA (A): B. Oliver Direct at 97:11-99:10.
610 PEPCO (2D): Gardiner Rebuttal at 9:3-5; 10:21-22.
611 PEPCO (2D): Gardiner Rebuttal at 9:5.
612 AOBA (A): B. Oliver Direct at 137:6-8.
613 AOBA (A): B. Oliver Direct at 101:6-12.
614 PEPCO (2D): Gardiner Rebuttal at 11:15.
615 PEPCO (2D): Gardiner Rebuttal at 11:16-19 (referencing MdPSC Case Nos. 9645, 9655, 9692 and 9692). She also explained that AOBA's position is based on the two isolated cost categories from which AOBA infers that the residential class should experience rapid increases in class cost responsibilities throughout an MYP. Although individual costs may indeed change between cases, this does not mean that the class rate of return will follow that trend, as the rate of return depends on multiple cost categories. The residential class actually saw an improved rate of return from FC 1156 to FC 1176, *Id*. at 12:9-18.
616 PEPCO (2D): Gardiner Rebuttal at 12:21-13:6.

Finally, although it provides no details to support its assertion, AOBA suggests that Pepco's income tax allocation in the CCOSS model is inappropriate.[617] Pepco continues to allocate income tax based on taxable income for each customer class at the Company's overall effective tax rates in accordance with well-established Commission precedent.[618] This method ensures that the same tax rate is applied to all customer classes.[619] AOBA presents no justification for the Commission to alter its position on the allocation of income tax in the CCOSS. Indeed, in FC 1156, the Commission, in language equally applicable here, held:

> Although AOBA has again raised the issue of the allocation of income tax in prior cases, the Commission declines to change our income tax pronouncements that "[t]axes are levied on the sums of money paid by customers for electric service, not on the basis of class rate base or some underlying 'costs' of the seller to provide the service." There is no compelling reason or basis warranting deviation from that position in this case.[620]

Company Witness Gardiner established that the Company's CCOSS is reasonable and consistent with Commission precedent. The Commission should find the CCOSS is reasonable and approve its use in this proceeding.

X. Pepco's Appliance Saturation Study and the Conditional Demand Analysis Based on Its Results Are Reasonable.

In response to the Commission directive in FC 1139,[621] in FC 1150, Pepco prepared a new Conditional Demand Analysis ("CDA") based on the results of the Company's most recent appliance saturation study. Company Witness Bonikowski provided that CDA as part of his Direct

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617 AOBA (A): B. Oliver Direct at 129:11-14.
618 PEPCO (2D): Gardiner Rebuttal at 13:17-18. *See* FC 1156, Order No. 20755 at ¶373; FC 1139, Order No. 18846 at ¶427; FC 1103, Order No. 17424 at ¶398; FC 1087, Order No. 16930 at ¶306.
619 PEPCO (2D): Gardiner Rebuttal at 13:18-19.
620 FC 1156, Order No. 20755 at ¶373.
621 Order No. 18846 at ¶536.

Testimony.[622] The results of the CDA reinforce the underlying justification for the existence of the first volumetric rate block of the residential rate structure as it confirms that 400 kWh remains a reasonable approximation of electric usage for basic needs.[623]

No other party presented testimony on this issue. The Commission should find that the Company's Appliance Saturation Study and CDA are reasonable and have been appropriately used in this proceeding.

Company Witness Bonikowski also provided a Distribution Marginal Cost Study as part of his Direct Testimony (PEPCO (E)-17) in order to comply with various Commission directives from FC 939 and earlier base rate proceedings that predate the divestiture of Pepco's generation plants.[624] However, as in each of the Company's other base rate cases since divestiture, the results of the Marginal Cost Study were not used in this proceeding.[625] No other party presented testimony regarding the Marginal Cost Study. The Company respectfully requests that the Commission direct that Pepco is no longer required to file a Marginal Cost Study as part of any future proceeding to establish rates for electric distribution service in the District of Columbia.

Y. The Adjusted Rate Base in the TTYCF and the 2023 Report Serve Different Purposes and Pepco Appropriately Reflected Its Rate Base in Each.

OPC and AOBA noted that there are differences between the rate base in the Rate of Return Report for the 12 Months ending December 31, 2023 that Pepco submitted in FC 1156 and the Company's filings in FC 1176 and claimed that these differences call into question the Company's

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[622] PEPCO (E)-16.
[623] PEPCO (E): Bonikowski Direct at 69:9-12.
[624] *See, e.g.*, FC 939, Order No. 10646.
[625] PEPCO (E): Bonikowski Direct at 70:1-2.

submissions in FC 1176.[626] Indeed, OPC and AOBA asserted that Pepco had overstated or inflated its rate base pointing to the Company's TTYCF filing.[627] This is not the case. As was explained in the Company's June 17, 2024 Response in Opposition to Motion to Dismiss or, in the Alternative, Motion for Summary Judgment ("Response"), these filings are appropriately different:

> There are important differences between the two presentations that would necessarily result in their numbers **not** being similar. Unlike the 2023 Report, which is intended to reflect actual ratemaking results for a historic period, as Company Witness Leming explained in his Supplemental Direct Testimony regarding the TTYCF, Pepco's TTYCF includes a number of ratemaking adjustments for known and measurable changes that need to be made to the 2023 test year so that it is more reflective of the rate effective period, which is a period beyond 2023. As Company Witness Leming detailed, the TTYCF includes adjustments to annualize test year cost increases and include pro forma adjustments to provide more contemporaneous recovery or better represent a future period. For example, among other adjustments, the TTYCF included specific adjustments to:
>
> - Annualize test-year reliability closings (TTYCF RMA 1);
> - Annualize the remainder of rate base (TTYCF RMA 4);
> - Reflect the Company's proposed Bill Stabilization Adjustment regulatory asset in rate base (TTYCF RMA 12);
> - Reflect an adjustment to non-labor O&M expense for inflation (TTYCF RMA 34); and
> - Annualize depreciation expense ((TTYCF RMA 3).[628]

In fact, as Pepco explained in its Response a comparison of the unadjusted projections for 2023 from the TTYCF and unadjusted results reported in the 2023 Report shows that these figures to be very close and indicates that Pepco's projections actually understated the Company's financial need.[629]

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626 Tr. at 59, 62, 64, 99-100.
627 *Id*.
628 Response at 8-9 (emphasis in original).
629 Response at 10.

Some parties have also suggested that the Company should refile its submissions to reflect actual 2023 results. However, this is unnecessary due to the MYP's annual reconciliation process, because variances occurring in 2023 will get incorporated into the 2024 annual reconciliation. Moreover, none of the Commission's orders in FC 1176 required or even contemplated the filing of updated numbers. Additionally, such updating is not required by the Commission's rules, the AFOR Order or any Commission order in this proceeding. To the contrary, Rule 213.2 states, with respect to the use of a partially projected test year: "Within one hundred eighty (180) days of the completion of the rate proceeding, a utility shall file an actual historical cost-of-service study for the entire proposed test year."[630]

Z. The Company Has Demonstrated that an Increase of $108.1 Million Would be Warranted under Traditional Ratemaking and the Disallowances Proposed by AOBA and OPC to the TTYCF Must be Rejected.

For the reasons set forth herein, the MYP proposed by Pepco is reasonable, in the public interest and should be approved by the Commission, In response to Commission direction, Pepco submitted the TTYCF but is not advocating for its acceptance as an alternative to the MYP. As stated in Pepco's Pre-Hearing brief, if the Commission were to approve rates based on a historical test year, the Company would have to consider filing rate cases on an annual basis given the pace of investment required to maintain a safe, reliable, and resilient system that meets the needs of customers and helps advance the District's climate goals.[631] If the Commission does not grant Pepco's request to implement its MYP at this time, the Company has through its testimony

[630] 15 D.C.M.R. §213.2.
[631] Pepco's Pre-Hearing Brief at 28.

demonstrated that a $108.1 million increase in District of Columbia base distribution rates is reasonable. The requested disallowances should be denied.

Specifically, in Pepco's Rebuttal Testimony, the Company presents its updated TTYCF revenue requirement of $108.1 million.[632] This updated revenue requirement includes the effect of RMA 38 (tax effect of proforma interest expense) and RMA 39 (removal of costs related to DC CREF meters) but does not include the effect of a ten-year amortization for a portion of the BSA deferral balances, which if approved would add an additional $4.2 million to the revenue requirement.[633]

Intervenors did propose several disallowances to Pepco's TTYCF revenue requirement; however, the Rebuttal Testimony of Pepco Witness Leming addresses each and demonstrates that Pepco's revenue requirement presented in rebuttal testimony is just and reasonable.[634] For example, OPC Witness Gorman and AOBA Witness T. Oliver contest including a return on the BSA deferral balance.[635] However, as pointed out by Company Witness Leming,[636] the Commission's independent BSA auditor recommended allowing a return on the BSA deferral balance, which is necessary to mitigate potential negative impacts resulting from the high balance on Pepco's credit metrics. In addition, OPC proposed several capital disallowances related to the TTYCF.[637] These proposed disallowances related to projects not included in the TTYCF revenue

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632 PEPCO (3B): Leming Rebuttal at 41:7-12.
633 PEPCO (3B): Leming Rebuttal at 33:7-17.
634 OPC's depreciation and ROE positions, not addressed here, would also decrease Pepco's TTYCF revenue requirement. Similarly, AOBA's ROE, New Business (referred to as customer connections) and Lead-Lag Study arguments would have corresponding effects on the revenue requirements for TTYCF, but are addressed elsewhere.
635 OPC (B): Gorman Direct at 46:8-10; AOBA (B) at 26:20-27:8.
636 PEPCO (3B): 29:8-15.
637 OPC(E): Mara Direct at 43-46.

requirement because they did not go into service in 2023.[638] As such, the capital disallowances proposed by OPC should not be accepted. AOBA also suggests disallowances of several projects, which according to the testimony of AOBA Witness B Oliver, span both the MYP and TTYCF, on the belief that the projects were not adequately supported.[639] However, as explained in the Rebuttal Testimony of Company Witness Cantler, AOBA based its position on preliminary budget estimates and not the final budgets presented in PEPCO (H)-2, the exhibit required for base rate filings and at issue in this case.[640] As such, the Commission should not accept AOBA's proposed disallowances for projects cited by AOBA in the TTYCF. Furthermore, OPC Witness Gorman proposed an adjustment to RMA 35, which relates to Inflation of Non-Labor O&M expenses, while AOBA testifies that it should be rejected in its entirety.[641] Specifically, OPC Witness Gorman proposes using a lower inflation rate, which is based on a six-month projection period.[642] The Commission should reject this adjustment because a more reasonable approach, as proposed by Pepco, uses a longer-term view of inflation to inform what is expected in the rate effective period.[643] OPC Witness Gorman also proposed to amortize Pepco's TTYCF regulatory assets over a six-year period, which is the same recovery period he suggests for MYP regulatory assets.[644] While Pepco maintains its objection to adopting the TTYCF Pepco does not contest this adjustment if the Commission finds it reasonable. Finally, OPC proposed an adjustment to Pepco's 2023 revenues to reflect end-of-year growth that occurred during 2023.[645] Pepco does not disagree with

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638 PEPCO (3B): Leming Rebuttal at 34:9-13.
639 AOBA (A): B. Oliver Direct at 74:1-10.
640 PEPCO (4H): Cantler Rebuttal at 10-13:6.
641 AOBA (B): T Oliver Direct at 28:5-11.
642 OPC(B): Gorman Direct at Exhibit (B)-14.
643 PEPCO(3B): Leming Rebuttal at 35:14-20.
644 OPC(B): Gorman Direct at 8:28-32.
645 OPC(B): Gorman Direct at 42:14-43:8.

this adjustment, again subject to its position that the proposed MYP should be approved.[646] Should the Commission adopt this adjustment, billing determinants used to design rates for the TTYCF should be modified in the manner detailed in Company Witness Bonikowski's Rebuttal testimony.[647]

IV. CONCLUSION

For the reasons set forth herein, the Pre-Hearing Brief and the record in this proceeding, the Commission should approve the Company's proposed MYP.

Respectfully submitted,

POTOMAC ELECTRIC POWER COMPANY

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August 30, 2024

[646] PEPCO (3B): Leming Rebuttal at 28:18-22.
[647] PEPCO (3E): Bonikowski Rebuttal at 51:11-52:7.

APPENDIX A

R.T. Leming
Rebuttal Testimony Exhibit
DC P.S.C. - - February 27, 2024

Introduced as:
PEPCO _________(3B) - 1

Potomac Electric Power Company

District of Columbia
Ratemaking Results - Distribution Only
Multi-Year Plan

(Thousands of Dollars)

		HTY - 12 ME December 31, 2022			Bridge Year - 12 ME December 31, 2023			MYP Year (1) - 12 ME December 31, 2024			MYP Year (2) - 12 ME December 31, 2025			MYP Year (3) - 12 ME December 31, 2026		
Line No.		Average Unadjusted (1)	Ratemaking Adjustments (2)	D.C. Adjusted (3)	Average Unadjusted (1)	Ratemaking Adjustments (2)	D.C. Adjusted (3)	Average Unadjusted (1)	Ratemaking Adjustments (2)	D.C. Adjusted (3)	Average Unadjusted (1)	Ratemaking Adjustments (2)	D.C. Adjusted (3)	Average Unadjusted (1)	Ratemaking Adjustments (2)	D.C. Adjusted (3)
	Rate Base															
1	Electric Plant in Service	$ 4,592,885	$ (12,498)	$ 4,580,387	$ 4,942,429	$ (13,800)	$ 4,928,629	$ 5,314,023	$ (14,753)	$ 5,299,270	$ 5,696,101	$ (13,576)	$ 5,682,525	$ 6,045,534	$ (20,513)	$ 6,025,021
2	Accumulated Depreciation	(1,418,851)	1,148	(1,417,703)	(1,500,335)	1,542	(1,498,793)	(1,591,366)	(3,658)	(1,595,024)	(1,691,575)	(15,413)	(1,706,988)	(1,801,847)	(28,033)	(1,829,880)
3	Accumulated Amortization	(35,936)	-	(35,936)	(51,797)	46	(51,751)	(67,769)	(435)	(68,204)	(84,349)	(1,860)	(86,209)	(103,298)	(3,566)	(106,864)
4	Materials and Supplies	54,495	-	54,495	57,620	-	57,620	57,422	-	57,422	57,725	-	57,725	57,993	-	57,993
5	Cash Working Capital	8,800	13,606	22,406	8,109	15,773	23,882	7,977	15,835	23,812	7,562	15,901	23,463	7,212	16,129	23,341
6	Accumulated Deferred Income Taxes	(794,119)	268	(793,851)	(789,882)	376	(789,506)	(798,633)	2,079	(796,554)	(821,867)	5,296	(816,571)	(844,779)	8,698	(836,081)
7	Prepaid Pension/OPEB Liab. (net of tax)	65,010	-	65,010	58,620	-	58,620	54,893	-	54,893	50,430	-	50,430	46,908	-	46,908
8	Customer Deposits	(8,780)	-	(8,780)	(9,050)	-	(9,050)	(8,986)	-	(8,986)	(8,986)	-	(8,986)	(8,986)	-	(8,986)
9	Pepco Portion of Servco Assets	13,099	-	13,099	8,717	-	8,717	6,123	-	6,123	4,428	-	4,428	4,943	-	4,943
10	Regulatory Assets	33,292	(1,817)	31,475	28,376	(1,698)	26,678	19,151	14,468	33,619	13,173	10,985	24,158	8,828	6,434	15,262
11	Unamortized Credit Facility Costs	340	-	340	298	-	298	215	-	215	133	-	133	49	-	49
12	**Total Rate Base**	**$ 2,510,235**	**$ 707**	**$ 2,510,942**	**$ 2,753,106**	**$ 2,239**	**$ 2,755,345**	**$ 2,993,051**	**$ 13,536**	**$ 3,006,587**	**$ 3,222,775**	**$ 1,333**	**$ 3,224,108**	**$ 3,412,556**	**$ (20,851)**	**$ 3,391,705**
	Operating Revenues															
13	Sale of Electricity	$ 610,199	$ 15,025	$ 625,224	$ 674,430	$ -	$ 674,430	$ 673,801	$ -	$ 673,801	$ 671,328	$ -	$ 671,328	$ 668,661	$ -	$ 668,661
14	Other Revenues	6,847		6,847	4,552		4,552	4,566		4,566	4,580		4,580	4,604		4,604
15	Operating Revenues	$ 617,046	$ 15,025	$ 632,071	$ 678,982	$ -	$ 678,982	$ 678,367	$ -	$ 678,367	$ 675,908	$ -	$ 675,908	$ 673,265	$ -	$ 673,265
	Operating Expenses															
16	Operation and Maintenance	$ 173,915	$ (9,737)	$ 164,178	$ 184,371	$ (5,033)	$ 179,338	$ 189,682	$ (4,447)	$ 185,235	$ 190,760	$ (4,635)	$ 186,125	$ 194,647	$ (4,737)	$ 189,910
17	Depreciation	123,942	(395)	123,547	133,177	(429)	132,748	141,512	11,349	152,861	151,889	12,145	164,034	160,883	13,050	173,933
18	Amortization	16,058	-	16,058	27,569	(469)	27,100	25,970	5,963	31,933	23,477	7,206	30,683	27,028	7,188	34,216
19	Other Taxes	150,391	-	150,391	151,560	-	151,560	152,582	-	152,582	151,791	-	151,791	150,914	-	150,914
20	D.C. Income Tax	(19,527)	2,075	(17,452)	6,733	484	7,217	7,905	(1,088)	6,817	6,884	(1,217)	5,667	4,971	(1,237)	3,734
21	Federal Income Tax	3,646	4,844	8,490	5,975	1,133	7,108	2,144	(2,545)	(401)	(1,127)	(2,844)	(3,971)	(5,597)	(2,889)	(8,486)
22	Total Operating Expenses	$ 448,425	$ (3,213)	$ 445,212	$ 509,386	$ (4,314)	$ 505,072	$ 519,795	$ 9,232	$ 529,027	$ 523,675	$ 10,655	$ 534,330	$ 532,847	$ 11,375	$ 544,222
23	**Operating Income**	**$ 168,621**	**$ 18,238**	**$ 186,859**	**$ 169,596**	**$ 4,314**	**$ 173,910**	**$ 158,571**	**$ (9,232)**	**$ 149,339**	**$ 152,233**	**$ (10,655)**	**$ 141,578**	**$ 140,418**	**$ (11,375)**	**$ 129,043**
24	**D.C. Jurisdictional Return on Rate Base**	**6.72%**		**7.44%**	**6.16%**		**6.31%**	**5.30%**		**4.97%**	**4.72%**		**4.39%**	**4.11%**		**3.80%**
25	Less Weighted Cost of Long-Term Debt	2.31%		2.31%	2.35%		2.35%	2.47%		2.47%	2.48%		2.48%	2.49%		2.49%
26	Net amount available for common equity	4.41%		5.13%	3.81%		3.96%	2.83%		2.50%	2.24%		1.91%	1.62%		1.31%
27	Common Equity ratio	50.68%		50.68%	50.68%		50.68%	50.50%		50.50%	50.50%		50.50%	50.50%		50.50%
		For Informational Purposes Only			**For Informational Purposes Only**											
28	**Earned D.C. Jurisdictional Return on Equity**	**8.702%**		**10.122%**	**7.518%**		**7.814%**	**5.604%**		**4.950%**	**4.436%**		**3.782%**	**3.208%**		**2.594%**
29	Requested Rate of Return			7.01%			7.05%			7.77%			7.78%			7.79%
30	**Cumulative Revenue Requirement**			**$ (14,958)**			**$ 28,064**			**$ 116,266**			**$ 150,736**			**$ 186,488**
31	**Projected Earned ROE**			**10.122%**			**7.814%**			**10.50%**			**10.50%**			**10.50%**
32	**Total Adjusted Distribution Revenue Requirement**															
33	**Cumulative Revenue Requirement**									**$ 116,266**			**$ 150,736**			**$ 186,488**
34	**Total Distribution Revenues, Adjusted**									**$ 794,632**			**$ 826,644**			**$ 859,752**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Analysis of Revenue Requirement -- Distribution Only
Multi-Year Plan

(Thousands of Dollars)		HTY - 12 ME December 31, 2022			Bridge Year - 12 ME December 31, 2023			MYP Year (1) - 12 ME December 31, 2024			MYP Year (2) - 12 ME December 31, 2025			MYP Year (3) - 12 ME December 31, 2026		
		Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement
	Unadjusted Amounts	$ 2,510,235	168,621	$ 10,135	$ 2,753,106	169,596	$ 33,798	$ 2,993,051	158,571	$ 102,078	$ 3,222,775	152,233	$ 135,893	$ 3,412,556	140,418	$ 173,035
	Adjustments															
1	Removal of DC Power Line Undergrounding (DC PLUG) initiative costs	$ (9,041)	$ 467	$ (1,519)	$ (8,711)	$ 565	$ (1,627)	$ (8,393)	$ 668	$ (1,821)	$ (8,088)	$ 630	$ (1,737)	$ (7,792)	$ 532	$ (1,571)
2	Removal of supplemental executive retirement plan (SERP) costs	(1,161)	507	(812)	(1,387)	907	(1,386)	(1,577)	722	(1,165)	(1,761)	758	(1,235)	(1,928)	798	(1,308)
3	Removal of certain executive incentive plan costs	(880)	1,321	(1,908)	(1,002)	1,296	(1,885)	(1,078)	1,326	(1,945)	(1,155)	1,335	(1,966)	(1,227)	1,363	(2,012)
4	Removal of adjustments to deferred compensation balances	-	(106)	146	-	22	(30)	-	22	(30)	-	22	(30)	-	24	(33)
5	Removal of employee association costs	-	27	(37)	-	27	(37)	-	27	(37)	-	27	(37)	-	28	(39)
6	Removal of industry contributions and membership fees	-	378	(522)	-	468	(646)	-	472	(651)	-	485	(669)	-	496	(684)
7	Removal of institutional advertising/selling expenses	-	476	(657)	-	438	(604)	-	473	(653)	-	498	(687)	-	523	(722)
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs	-	(143)	197	-	(391)	539	-	(428)	590	-	(428)	590	-	(430)	593
9	Removal of executive perquisite expenses	-	47	(65)	-	47	(65)	-	47	(65)	-	47	(65)	-	48	(66)
10	Adjustment of BSC Billed Depreciation (Merger Commitment 39)	-	577	(796)	-	577	(796)	-	577	(796)	-	576	(795)	-	585	(807)
11	Removal of Benning Environmental Accrual (A)	-	298	(411)	-		-	-	-	-	-	-	-	-		-
11	Reflection of Benning Regulatory Asset (B) - Actual RI/FS Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Reflection of Benning Regulatory Asset (C) - Forecasted RI/FS Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Reflection of Benning Insurance Proceeds	-	-	-	-	-	-	(285)	569	(816)	-	-	-	-	-	-
13	Removal of Buzzard Point Environmental Remediation Costs	-	3,495	(4,822)	-	-	-	-	-	-	-	-	-	-	-	-
14	Removal of GAAP BSA Revenue Recognition Reserve	-	10,890	(15,024)		-	-	-	-	-	-	-	-	-	-	-
15	Reflection of PHISCO DDIT	-	-	-	-	-	-	3,818	(848)	1,579	2,970	(848)	1,489	2,121	(848)	1,398
16	Reflection of Climate Solutions Plan (CSP) Programs	-	-	-	-	-	-	1,037	(609)	951	2,814	(1,036)	1,731	2,907	(957)	1,633
17	Reflection of Regulatory Asset for COVID-19 related costs	-	-	-	-	-	-	8,314	(1,848)	3,441	6,467	(1,848)	3,244	4,619	(1,848)	3,046
18	Reflection of Real Estate & Facility Costs	-	-	-	-	-	-	-	-	-	-	-	-	4,550	(359)	984
19	DER Interconnection	-	-	-	-	-	-	1,952	(879)	1,422	3,313	(745)	1,383	2,124	(749)	1,262
20	EDIT Balance	-	-	-	-	-	-	217	(109)	174	381	(109)	191	272	(109)	180
21	House of Worship Credit	-	-	-	-	-	-	28	(55)	79	-	-	-	-	-	-
22	Reflection of Current Case Costs	-	-	-	-	-	-	2,337	(935)	1,540	1,402	(935)	1,440	467	(935)	1,340
23	Reflection of Electric Vehicle Regulatory Asset	-	-	-	-	-	-	1,777	(517)	904	1,812	(517)	908	1,295	(517)	852
24	Small DER Cost Sharing Petition	-	-	-	-	-	-	196	(5)	28	572	(8)	72	921	(13)	117
25	Adjustments to Depreciation Rates	-	-	-	-	-	-	(4,279)	(8,641)	11,463	(13,248)	(9,313)	11,427	(22,870)	(9,900)	11,201
26	Reflection of 2021 Lead Lag Study	13,829	-	1,337	16,034	-	1,560	16,058	-	1,721	16,143	-	1,733	16,371	-	1,759
27	Adjustments to Cash Working Capital Allowance	(223)	-	(22)	(261)	-	(25)	(223)	-	(24)	(242)	-	(26)	(242)	-	(26)
28	Tax Effect of Proforma Interest Expense	-	4	(6)	-	14	(19)	-	92	(127)		9	(12)	-	(143)	197
29	Reflection of Capital Project Updates	-	-	-	(736)	105	(216)	(4,600)	369	(1,002)	(8,576)	467	(1,565)	(21,253)	758	(3,330)
30	Removal of DC CREF Meters	-	-	-	-	-	-	(303)	39	(86)	(250)	39	(81)	(204)	39	(76)
31	Removal of Benning RI/FS Regulatory Asset & Amortization (Order 21884)	(1,817)	-	(176)	(1,698)	239	(495)	(1,460)	239	(486)	(1,221)	239	(461)	(982)	239	(435)
	Total Adjustments	**$ 707**	**$ 18,238**	**$ (25,097)**	**$ 2,239**	**$ 4,314**	**$ (5,732)**	**$ 13,536**	**$ (9,232)**	**$ 14,188**	**$ 1,333**	**$ (10,655)**	**$ 14,842**	**$ (20,851)**	**$ (11,375)**	**$ 13,453**
		Informational Purposes Only			**Informational Purposes Only**											
Total Revenue Requirement at % Rate of Return (Adj. Results)		**$ 2,510,942**	**$ 186,859**	**$ (14,958)**	**$ 2,755,345**	**$ 173,910**	**$ 28,064**	**$ 3,006,587**	**$ 149,339**	**$ 116,266**	**$ 3,224,108**	**$ 141,578**	**$ 150,736**	**$ 3,391,705**	**$ 129,043**	**$ 186,488**

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Multi-Year Plan
HTY - 12 ME December 31, 2022

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)	Operating Income (9)
1	Removal of DC Power Line Undergrounding (DC PLUG) initiative costs			$ (414)	$ (230)			$ 53	$ 124	$ 467
	Electric Plant in Service	$ (9,692)								
	Accumulated Depreciation	$ 383								
	Accumulated Deferred Income Taxes	$ 268								
2	Removal of supplemental executive retirement plan (SERP) costs			$ (600)	$ (100)			$ 58	$ 135	$ 507
	Electric Plant in Service	$ (1,706)								
	Accumulated Depreciation	$ 545								
3	Removal of certain executive incentive plan costs			$ (1,757)	$ (65)			$ 150	$ 351	$ 1,321
	Electric Plant in Service	$ (1,100)								
	Accumulated Depreciation	$ 220								
4	Removal of adjustments to deferred compensation balances			$ 146				$ (12)	$ (28)	$ (106)
5	Removal of employee association costs			$ (37)				$ 3	$ 7	$ 27
6	Removal of industry contributions and membership fees			$ (522)				$ 43	$ 101	$ 378
7	Removal of institutional advertising/selling expenses			$ (656)				$ 54	$ 126	$ 476
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs			$ 197				$ (16)	$ (38)	$ (143)
9	Removal of executive perquisite expenses			$ (65)				$ 5	$ 13	$ 47
10	Adjustment of BSC Billed Depreciation (Merger Commitment 39)			$ (796)				$ 66	$ 153	$ 577
11	Removal of Benning Environmental Accrual (A)	$ -		$ (411)				$ 34	$ 79	$ 298
11	Reflection of Benning Regulatory Asset (B) - Actual RI/FS Costs									
	Regulatory Assets									
11	Reflection of Benning Regulatory Asset (C) - Forecasted RI/FS Costs									
	Regulatory Assets									
12	Reflection of Benning Insurance Proceeds									
	Regulatory Assets									
13	Removal of Buzzard Point Environmental Remediation Costs			$ (4,822)		$ -		$ 398	$ 929	$ 3,495
14	Removal of GAAP BSA Revenue Recognition Reserve		$ 15,025					$ 1,240	$ 2,895	$ 10,890
15	Reflection of PHISCO DDIT					$ -				$ -
	Regulatory Assets	$ -								
16	Reflection of Climate Solutions Plan (CSP) Programs			$ -		$ -		$ -	$ -	$ -
	Electric Plant in Service	$ -								
	Accumulated Amortization	$ -								
	Accumulated Deferred Income Taxes	$ -								
17	Reflection of Regulatory Asset for COVID-19 related costs					$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
18	Reflection of Real Estate & Facility Costs				$ -			$ -	$ -	$ -
	Electric Plant in Service	$ -								
	Accumulated Depreciation	$ -								
	Accumulated Deferred Income Taxes	$ -								
19	DER Interconnection									
20	EDIT Balance									
21	House of Worship Credit					$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
22	Reflection of Current Case Costs					$ -				$ -
	Regulatory Assets	$ -								
23	Reflection of Electric Vehicle Regulatory Asset					$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
24	Small DER Cost Sharing Petition					$ -		$ -	$ -	$ -
	Electric Plant in Service									
	Accumulated Depreciation									
	Accumulated Deferred Income Taxes									
	Regulatory Assets									
25	Adjustments to Depreciation Rates				$ -			$ -	$ -	$ -
	Accumulated Depreciation	$ -								
	Accumulated Deferred Income Taxes	$ -								
26	Reflection of 2021 Lead Lag Study									
	Cash Working Capital	$ 13,829								
27	Adjustments to Cash Working Capital Allowance									
	Cash Working Capital	$ (223)								
28	Tax Effect of Proforma Interest Expense							$ (1)	$ (3)	$ 4
29	Reflection of Capital Project Updates									$ -
	Electric Plant in Service									
	Accumulated Depreciation									
	Accumulated Amortization									
	Accumulated Deferred Income Taxes									
30	Removal of DC CREF Meters									$ -
	Electric Plant in Service									
	Accumulated Depreciation									
	Accumulated Deferred Income Taxes									
31	Removal of Benning RI/FS Regulatory Asset & Amortization (Order 21884)				$ -	$ -		$ -	$ -	$ -
	Regulatory Assets	$ (1,817)								
	Total Ratemaking Adjustments	$ 707	$ 15,025	$ (9,737)	$ (395)	$ -	$ -	$ 2,075	$ 4,844	$ 18,238

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Multi-Year Plan
Bridge Year - 12 ME December 31, 2023

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)	Operating Income (9)
1	Removal of DC Power Line Undergrounding (DC PLUG) initiative costs			$ (549)	$ (230)			$ 64	$ 150	$ 565
	Electric Plant in Service	$ (9,692)								
	Accumulated Depreciation	$ 613								
	Accumulated Deferred Income Taxes	$ 368								
2	Removal of supplemental executive retirement plan (SERP) costs			$ (1,132)	$ (119)			$ 103	$ 241	$ 907
	Electric Plant in Service	$ (2,032)								
	Accumulated Depreciation	$ 645								
3	Removal of certain executive incentive plan costs			$ (1,714)	$ (75)			$ 148	$ 345	$ 1,296
	Electric Plant in Service	$ (1,284)								
	Accumulated Depreciation	$ 282								
4	Removal of adjustments to deferred compensation balances			$ (30)				$ 2	$ 6	$ 22
5	Removal of employee association costs			$ (37)				$ 3	$ 7	$ 27
6	Removal of industry contributions and membership fees			$ (645)				$ 53	$ 124	$ 468
7	Removal of institutional advertising/selling expenses			$ (605)				$ 50	$ 117	$ 438
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs			$ 540				$ (45)	$ (104)	$ (391)
9	Removal of executive perquisite expenses			$ (65)				$ 5	$ 13	$ 47
10	Adjustment of BSC Billed Depreciation (Merger Commitment 39)			$ (796)				$ 66	$ 153	$ 577
11	Removal of Benning Environmental Accrual (A)	$ -		$ -	$ -					
11	Reflection of Benning Regulatory Asset (B) - Actual RI/FS Costs									$ -
	Regulatory Assets									
11	Reflection of Benning Regulatory Asset (C) - Forecasted RI/FS Costs									
	Regulatory Assets									
12	Reflection of Benning Insurance Proceeds									
	Regulatory Assets									
13	Removal of Buzzard Point Environmental Remediation Costs									$ -
14	Removal of GAAP BSA Revenue Recognition Reserve			$ -						$ -
15	Reflection of PHISCO DDIT					$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
16	Reflection of Climate Solutions Plan (CSP) Programs			$ -		$ -		$ -	$ -	$ -
	Electric Plant in Service	$ -								
	Accumulated Amortization	$ -								
	Accumulated Deferred Income Taxes	$ -								
17	Reflection of Regulatory Asset for COVID-19 related costs					$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
18	Reflection of Real Estate & Facility Costs				$ -			$ -	$ -	$ -
	Electric Plant in Service	$ -								
	Accumulated Depreciation	$ -								
	Accumulated Deferred Income Taxes	$ -								
19	DER Interconnection			$ -				$ -	$ -	$ -
20	EDIT Balance									
21	House of Worship Credit					$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
22	Reflection of Current Case Costs			$ -		$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
23	Reflection of Electric Vehicle Regulatory Asset					$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
24	Small DER Cost Sharing Petition					$ -		$ -	$ -	$ -
	Electric Plant in Service									
	Accumulated Depreciation									
	Accumulated Deferred Income Taxes									
	Regulatory Assets									
25	Adjustments to Depreciation Rates				$ -			$ -	$ -	$ -
	Accumulated Depreciation	$ -								
	Accumulated Deferred Income Taxes	$ -								
26	Reflection of 2021 Lead Lag Study									
	Cash Working Capital	$ 16,034								
27	Adjustments to Cash Working Capital Allowance									
	Cash Working Capital	$ (261)								
28	Tax Effect of Proforma Interest Expense							$ (4)	$ (10)	$ 14
29	Reflection of Capital Project Updates				$ (5)	$ (140)		$ 12	$ 28	$ 105
	Electric Plant in Service	$ (792)								
	Accumulated Depreciation	$ 2								
	Accumulated Amortization	$ 46								
	Accumulated Deferred Income Taxes	$ 8								
30	Removal of DC CREF Meters									$ -
	Electric Plant in Service									
	Accumulated Depreciation									
	Accumulated Deferred Income Taxes									
31	Removal of Benning RI/FS Regulatory Asset & Amortization (Order 21884)					$ (329)		$ 27	$ 63	$ 239
	Regulatory Assets	$ (1,698)								
	Total Ratemaking Adjustments	**$ 2,239**	**$ -**	**$ (5,033)**	**$ (429)**	**$ (469)**	**$ -**	**$ 484**	**$ 1,133**	**$ 4,314**

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Multi-Year Plan
MYP Year (1) - 12 ME December 31, 2024

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)	Operating Income (9)
1	Removal of DC Power Line Undergrounding (DC PLUG) initiative costs			$ (691)	$ (230)			$ 76	$ 177	$ 668
	Electric Plant in Service	$ (9,692)								
	Accumulated Depreciation	$ 843								
	Accumulated Deferred Income Taxes	$ 456								
2	Removal of supplemental executive retirement plan (SERP) costs			$ (859)	$ (137)			$ 82	$ 192	$ 722
	Electric Plant in Service	$ (2,339)								
	Accumulated Depreciation	$ 762								
3	Removal of certain executive incentive plan costs			$ (1,746)	$ (84)			$ 151	$ 353	$ 1,326
	Electric Plant in Service	$ (1,432)								
	Accumulated Depreciation	$ 354								
4	Removal of adjustments to deferred compensation balances			$ (30)				$ 2	$ 6	$ 22
5	Removal of employee association costs			$ (37)				$ 3	$ 7	$ 27
6	Removal of industry contributions and membership fees			$ (651)				$ 54	$ 125	$ 472
7	Removal of institutional advertising/selling expenses			$ (653)				$ 54	$ 126	$ 473
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs			$ 591				$ (49)	$ (114)	$ (428)
9	Removal of executive perquisite expenses			$ (65)				$ 5	$ 13	$ 47
10	Adjustment of BSC Billed Depreciation (Merger Commitment 39)			$ (796)				$ 66	$ 153	$ 577
11	Removal of Benning Environmental Accrual (A)									
11	Reflection of Benning Regulatory Asset (B) - Actual RI/FS Costs									
	Regulatory Assets									
11	Reflection of Benning Regulatory Asset (C) - Forecasted RI/FS Costs									
	Regulatory Assets									
12	Reflection of Benning Insurance Proceeds					$ (785)		$ 65	$ 151	$ 569
	Regulatory Assets	$ (285)								
13	Removal of Buzzard Point Environmental Remediation Costs									$ -
14	Removal of GAAP BSA Revenue Recognition Reserve									$ -
15	Reflection of PHISCO DDIT					$ 1,171		$ (97)	$ (226)	$ (848)
	Regulatory Assets	$ 3,818								
16	Reflection of Climate Solutions Plan (CSP) Programs			$ 299		$ 541		$ (69)	$ (162)	$ (609)
	Electric Plant in Service	$ 1,358								
	Accumulated Amortization	$ (271)								
	Accumulated Deferred Income Taxes	$ (50)								
17	Reflection of Regulatory Asset for COVID-19 related costs					$ 2,549		$ (210)	$ (491)	$ (1,848)
	Regulatory Assets	$ 8,314								
18	Reflection of Real Estate & Facility Costs				$ -			$ -	$ -	$ -
	Electric Plant in Service	$ -								
	Accumulated Depreciation	$ -								
	Accumulated Deferred Income Taxes	$ -								
19	DER Interconnection			$ 191		$ 1,022		$ (100)	$ (234)	$ (879)
	Electric Plant in Service	$ 2,556								
	Accumulated Amortization	$ (510)								
	Accumulated Deferred Income Taxes	$ (94)								
20	EDIT Balance									
	Regulatory Assets	$ 217				$ 150		$ (12)	$ (29)	$ (109)
21	House of Worship Credit					$ 76		$ (6)	$ (15)	$ (55)
	Regulatory Assets	$ 28								
22	Reflection of Current Case Costs					$ 1,290		$ (106)	$ (249)	$ (935)
	Regulatory Assets	$ 2,337								
23	Reflection of Electric Vehicle Regulatory Asset					$ 714		$ (59)	$ (138)	$ (517)
	Regulatory Assets	$ 1,777								
24	Small DER Cost Sharing Petition				$ 29	$ (23)		$ -	$ (1)	$ (5)
	Electric Plant in Service	$ 490								
	Accumulated Depreciation	$ (15)								
	Accumulated Deferred Income Taxes	$ (1)								
	Regulatory Assets	$ (278)								
25	Adjustments to Depreciation Rates				$ 11,921			$ (983)	$ (2,297)	$ (8,641)
	Accumulated Depreciation	$ (5,904)								
	Accumulated Deferred Income Taxes	$ 1,625								
26	Reflection of 2021 Lead Lag Study									
	Cash Working Capital	$ 16,058								
27	Adjustments to Cash Working Capital Allowance									
	Cash Working Capital	$ (223)								
28	Tax Effect of Proforma Interest Expense							$ (28)	$ (64)	$ 92
29	Reflection of Capital Project Updates				$ (96)	$ (413)		$ 42	$ 98	$ 369
	Electric Plant in Service	$ (5,045)								
	Accumulated Depreciation	$ 33								
	Accumulated Amortization	$ 346								
	Accumulated Deferred Income Taxes	$ 66								
30	Removal of DC CREF Meters				$ (54)			$ 4	$ 11	$ 39
	Electric Plant in Service	$ (649)								
	Accumulated Depreciation	$ 269								
	Accumulated Deferred Income Taxes	$ 77								
31	Removal of Benning RI/FS Regulatory Asset & Amortization (Order 21884)					$ (329)		$ 27	$ 63	$ 239
	Regulatory Assets	$ (1,460)								
	Total Ratemaking Adjustments	**$ 13,536**	**$ -**	**$ (4,447)**	**$ 11,349**	**$ 5,963**	**$ -**	**$ (1,088)**	**$ (2,545)**	**$ (9,232)**

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Multi-Year Plan
MYP Year (2) - 12 ME December 31, 2025

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)	Operating Income (9)
1	Removal of DC Power Line Undergrounding (DC PLUG) initiative costs			$ (639)	$ (230)			$ 72	$ 167	$ 630
	Electric Plant in Service	$ (9,692)								
	Accumulated Depreciation	$ 1,072								
	Accumulated Deferred Income Taxes	$ 532								
2	Removal of supplemental executive retirement plan (SERP) costs			$ (890)	$ (155)			$ 86	$ 201	$ 758
	Electric Plant in Service	$ (2,658)								
	Accumulated Depreciation	$ 897								
3	Removal of certain executive incentive plan costs			$ (1,749)	$ (93)			$ 152	$ 355	$ 1,335
	Electric Plant in Service	$ (1,590)								
	Accumulated Depreciation	$ 435								
4	Removal of adjustments to deferred compensation balances			$ (31)				$ 3	$ 6	$ 22
5	Removal of employee association costs			$ (37)				$ 3	$ 7	$ 27
6	Removal of industry contributions and membership fees			$ (669)				$ 55	$ 129	$ 485
7	Removal of institutional advertising/selling expenses			$ (687)				$ 57	$ 132	$ 498
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs			$ 591				$ (49)	$ (114)	$ (428)
9	Removal of executive perquisite expenses			$ (65)				$ 5	$ 13	$ 47
10	Adjustment of BSC Billed Depreciation (Merger Commitment 39)			$ (795)				$ 66	$ 153	$ 576
11	Removal of Benning Environmental Accrual (A)									
11	Reflection of Benning Regulatory Asset (B) - Actual RI/FS Costs									$ -
	Regulatory Assets									
11	Reflection of Benning Regulatory Asset (C) - Forecasted RI/FS Costs									
	Regulatory Assets									
12	Reflection of Benning Insurance Proceeds									
	Regulatory Assets									
13	Removal of Buzzard Point Environmental Remediation Costs									$ -
14	Removal of GAAP BSA Revenue Recognition Reserve			$ -						$ -
15	Reflection of PHISCO DDIT					$ 1,171		$ (97)	$ (226)	$ (848)
	Regulatory Assets	$ 2,970								
16	Reflection of Climate Solutions Plan (CSP) Programs			$ 336		$ 1,094		$ (118)	$ (276)	$ (1,036)
	Electric Plant in Service	$ 4,102								
	Accumulated Amortization	$ (1,088)								
	Accumulated Deferred Income Taxes	$ (200)								
17	Reflection of Regulatory Asset for COVID-19 related costs					$ 2,549		$ (210)	$ (491)	$ (1,848)
	Regulatory Assets	$ 6,467								
18	Reflection of Real Estate & Facility Costs				$ -			$ -	$ -	$ -
	Electric Plant in Service	$ -								
	Accumulated Depreciation	$ -								
	Accumulated Deferred Income Taxes	$ -								
19	DER Interconnection			$ -		$ 1,028		$ (85)	$ (198)	$ (745)
	Electric Plant in Service	$ 5,126								
	Accumulated Amortization	$ (1,532)								
	Accumulated Deferred Income Taxes	$ (281)								
20	EDIT Balance									
	Regulatory Assets	$ 381				$ 150		$ (12)	$ (29)	$ (109)
21	House of Worship Credit					$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
22	Reflection of Current Case Costs					$ 1,290		$ (106)	$ (249)	$ (935)
	Regulatory Assets	$ 1,402								
23	Reflection of Electric Vehicle Regulatory Asset					$ 714		$ (59)	$ (138)	$ (517)
	Regulatory Assets	$ 1,812								
24	Small DER Cost Sharing Petition				$ 58	$ (47)		$ (1)	$ (2)	$ (8)
	Electric Plant in Service	$ 1,470								
	Accumulated Depreciation	$ (58)								
	Accumulated Deferred Income Taxes	$ (14)								
	Regulatory Assets	$ (826)								
25	Adjustments to Depreciation Rates				$ 12,849			$ (1,060)	$ (2,476)	$ (9,313)
	Accumulated Depreciation	$ (18,278)								
	Accumulated Deferred Income Taxes	$ 5,030								
26	Reflection of 2021 Lead Lag Study									
	Cash Working Capital	$ 16,143								
27	Adjustments to Cash Working Capital Allowance									
	Cash Working Capital	$ (242)								
28	Tax Effect of Proforma Interest Expense							$ (3)	$ (6)	$ 9
29	Reflection of Capital Project Updates				$ (230)	$ (414)		$ 53	$ 124	$ 467
	Electric Plant in Service	$ (9,685)								
	Accumulated Depreciation	$ 196								
	Accumulated Amortization	$ 760								
	Accumulated Deferred Income Taxes	$ 153								
30	Removal of DC CREF Meters				$ (54)			$ 4	$ 11	$ 39
	Electric Plant in Service	$ (649)								
	Accumulated Depreciation	$ 323								
	Accumulated Deferred Income Taxes	$ 76								
31	Removal of Benning RI/FS Regulatory Asset & Amortization (Order 21884)					$ (329)		$ 27	$ 63	$ 239
	Regulatory Assets	$ (1,221)								
	Total Ratemaking Adjustments	**$ 1,333**	**$ -**	**$ (4,635)**	**$ 12,145**	**$ 7,206**	**$ -**	**$ (1,217)**	**$ (2,844)**	**$ (10,655)**

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Multi-Year Plan
MYP Year (3) - 12 ME December 31, 2026

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)	Operating Income (9)
1	Removal of DC Power Line Undergrounding (DC PLUG) initiative costs			$ (503)	$ (230)			$ 60	$ 141	$ 532
	Electric Plant in Service	$ (9,692)								
	Accumulated Depreciation	$ 1,302								
	Accumulated Deferred Income Taxes	$ 598								
2	Removal of supplemental executive retirement plan (SERP) costs			$ (927)	$ (174)			$ 91	$ 212	$ 798
	Electric Plant in Service	$ (2,979)								
	Accumulated Depreciation	$ 1,051								
3	Removal of certain executive incentive plan costs			$ (1,778)	$ (102)			$ 155	$ 362	$ 1,363
	Electric Plant in Service	$ (1,752)								
	Accumulated Depreciation	$ 525								
4	Removal of adjustments to deferred compensation balances			$ (33)				$ 3	$ 6	$ 24
5	Removal of employee association costs			$ (38)				$ 3	$ 7	$ 28
6	Removal of industry contributions and membership fees			$ (684)				$ 56	$ 132	$ 496
7	Removal of institutional advertising/selling expenses			$ (722)				$ 60	$ 139	$ 523
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs			$ 593				$ (49)	$ (114)	$ (430)
9	Removal of executive perquisite expenses			$ (66)				$ 5	$ 13	$ 48
10	Adjustment of BSC Billed Depreciation (Merger Commitment 39)			$ (806)				$ 66	$ 155	$ 585
11	Removal of Benning Environmental Accrual (A)									
11	Reflection of Benning Regulatory Asset (B) - Actual RI/FS Costs									
	Regulatory Assets									
11	Reflection of Benning Regulatory Asset (C) - Forecasted RI/FS Costs									
	Regulatory Assets									
12	Reflection of Benning Insurance Proceeds									
	Regulatory Assets									
13	Removal of Buzzard Point Environmental Remediation Costs									$ -
14	Removal of GAAP BSA Revenue Recognition Reserve			$ -						$ -
15	Reflection of PHISCO DDIT					$ 1,171		$ (97)	$ (226)	$ (848)
	Regulatory Assets	$ 2,121								
16	Reflection of Climate Solutions Plan (CSP) Programs			$ 227		$ 1,094		$ (109)	$ (255)	$ (957)
	Electric Plant in Service	$ 5,489								
	Accumulated Amortization	$ (2,182)								
	Accumulated Deferred Income Taxes	$ (400)								
17	Reflection of Regulatory Asset for COVID-19 related costs					$ 2,549		$ (210)	$ (491)	$ (1,848)
	Regulatory Assets	$ 4,619								
18	Reflection of Real Estate & Facility Costs				$ 495			$ (41)	$ (95)	$ (359)
	Electric Plant in Service	$ 4,779								
	Accumulated Depreciation	$ (248)								
	Accumulated Deferred Income Taxes	$ 19								
19	DER Interconnection			$ -		$ 1,033		$ (85)	$ (199)	$ (749)
	Electric Plant in Service	$ 5,153								
	Accumulated Amortization	$ (2,559)								
	Accumulated Deferred Income Taxes	$ (470)								
20	EDIT Balance									
	Regulatory Assets	$ 272				$ 150		$ (12)	$ (29)	$ (109)
21	House of Worship Credit					$ -		$ -	$ -	$ -
	Regulatory Assets	$ -								
22	Reflection of Current Case Costs					$ 1,290		$ (106)	$ (249)	$ (935)
	Regulatory Assets	$ 467								
23	Reflection of Electric Vehicle Regulatory Asset					$ 714		$ (59)	$ (138)	$ (517)
	Regulatory Assets	$ 1,295								
24	Small DER Cost Sharing Petition				$ 87	$ (70)		$ (1)	$ (3)	$ (13)
	Electric Plant in Service	$ 2,450								
	Accumulated Depreciation	$ (131)								
	Accumulated Deferred Income Taxes	$ (40)								
	Regulatory Assets	$ (1,358)								
25	Adjustments to Depreciation Rates				$ 13,659			$ (1,127)	$ (2,632)	$ (9,900)
	Accumulated Depreciation	$ (31,553)								
	Accumulated Deferred Income Taxes	$ 8,683								
26	Reflection of 2021 Lead Lag Study									
	Cash Working Capital	$ 16,371								
27	Adjustments to Cash Working Capital Allowance									
	Cash Working Capital	$ (242)								
28	Tax Effect of Proforma Interest Expense							$ 43	$ 100	$ (143)
29	Reflection of Capital Project Updates				$ (631)	$ (414)		$ 86	$ 201	$ 758
	Electric Plant in Service	$ (23,312)								
	Accumulated Depreciation	$ 644								
	Accumulated Amortization	$ 1,175								
	Accumulated Deferred Income Taxes	$ 240								
30	Removal of DC CREF Meters				$ (54)			$ 4	$ 11	$ 39
	Electric Plant in Service	$ (649)								
	Accumulated Depreciation	$ 377								
	Accumulated Deferred Income Taxes	$ 68								
31	Removal of Benning RI/FS Regulatory Asset & Amortization (Order 21884)					$ (329)		$ 27	$ 63	$ 239
	Regulatory Assets	$ (982)								
	Total Ratemaking Adjustments	**$ (20,851)**	**$ -**	**$ (4,737)**	**$ 13,050**	**$ 7,188**	**$ -**	**$ (1,237)**	**$ (2,889)**	**$ (11,375)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 11 (B) - Reflection of Benning Regulatory Asset - Actual RI/FS Costs		MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings				
1	Dollars Spent for the RI/FS from from 1/1/2018 through 12/31/2022	$ -			
2	Allocation to DC	57.7%			
3	Dollars Spent for the RI/FS from 1/1/2018 to Date - Pepco DC	$ -			
4	Adjustment to Amortization Expense (10 year amortization period)		$ -	$ -	$ -
5	Adjustment to D.C. Income Tax Expense		-	-	-
6	Adjustment to Federal Income Tax Expense		-	-	-
	Total Earnings		**$ -**	**$ -**	**$ -**
	Rate Base				
7	Average DC regulatory asset balance	$ -			
8	Decline in balance after Year 1	-			
9	Total average unamortized rate base balances		$ -	$ -	$ -
10	Adjustment to accumulated deferred income taxes		-	-	-
11	Adjustment to rate base, net of accumulated deferred taxes		$ -	$ -	$ -
	Total Rate Base		**$ -**	**$ -**	**$ -**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 11 (C) - Reflection of Benning Regulatory Asset - Forecasted RI/FS Costs	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings			
1	Future Costs for RI/FS - Pepco through Q1 2024	$ -	$ -	$ -
2	Allocation to DC	57.7%	57.7%	57.7%
3	Future Costs for RI/FS - Pepco through Q1 2024	$ -	$ -	$ -
4	Adjustment to Amortization Expense (10 year amortization period)	-	-	-
5	Adjustment to D.C. Income Tax Expense	-	-	-
6	Adjustment to Federal Income Tax Expense	-	-	-
	Total Earnings	**$ -**	**$ -**	**$ -**
	Rate Base			
7	Future Costs of RI/FS - Pepco DC Regulatory Asset	$ -	$ -	$ -
8	Decrease in balance due to amortization expense	-	-	-
9	Net Rate Base Impact - DC Regulatory Asset	$ -	$ -	$ -
10	Average Rate Base	-	-	-
11	Adjustment to accumulated deferred income taxes	-	-	-
12	Adjustment to rate base, net of accumulated deferred taxes	$ -	$ -	$ -
	Total Rate Base	**$ -**	**$ -**	**$ -**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 12 - Reflection of Benning Insurance Proceeds		MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings				
1	Benning Insurance Proceeds - Distribution DC (2018-2021 Amortization Expense)	$ (785)			
2	Adjustment to Amortization Expense (1 year amortization period)		$ (785)	$ -	$ -
3	Adjustment to D.C. Income Tax Expense		65	-	-
4	Adjustment to Federal Income Tax Expense		151	-	-
	Total Earnings		**$ 569**	**$ -**	**$ -**
5	Average DC regulatory liability balance	$ (785)			
6	Decline in balance after Year 1	393			
7	Total average unamortized rate base balances		$ (393)	$ -	$ -
8	Adjustment to accumulated deferred income taxes		108	-	-
9	Adjustment to rate base, net of accumulated deferred taxes		$ (285)	$ -	$ -
	Total Rate Base		**$ (285)**	**$ -**	**$ -**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 15 - Reflection of PHISCO DDIT		HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings						
1	PHISCO Deficient Deferred Income Tax Balances						
2	Non-Property Related (5 year amortization)	$ 5,853					
3	Adjustment to DC Distribution amortization expense		$ -	$ -	$ 1,171	$ 1,171	$ 1,171
4	Adjustment to D.C. Income Tax Expense		$ -	$ -	$ (97)	$ (97)	$ (97)
5	Adjustment to Federal Income Tax Expense		$ -	$ -	$ (226)	$ (226)	$ (226)
	Total Earnings		**$ -**	**$ -**	**$ (848)**	**$ (848)**	**$ (848)**
	Rate Base						
6	Average DC Regulatory Asset Balance	$ 5,853					
7	Decline in Balance After Year 1	(586)					
8	Average unamortized regulatory asset balance		$ -	$ -	$ 5,268	$ 4,097	$ 2,926
9	Adjustment to accumulated deferred income taxes				(1,450)	(1,127)	(805)
10	Average adjustment to rate base, net of accumulated deferred taxes		$ -	$ -	$ 3,818	$ 2,970	$ 2,121
	Total Rate Base		**$ -**	**$ -**	**$ 3,818**	**$ 2,970**	**$ 2,121**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 16 - Reflection of Climate Solutions Plan (CSP) Programs	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings					
1	Electric Plant in Service	$ -	$ -	$ 6,076	$ 12,215	$ 12,215
2	Allocation to distribution (Labor Ratio)	85.75%	85.75%	85.75%	85.75%	85.75%
3	Allocation to D.C. (Plant less AFUDC ratio)	51.41%	52.04%	52.12%	52.40%	52.40%
4	D.C. distribution electric plant in service	$ -	$ -	$ 2,715	$ 5,489	$ 5,489
5	Adjustment to D.C. amortization expense	$ -	$ -	$ 541	$ 1,094	$ 1,094
6	Adjustment to O&M expense	$ -	$ -	$ 800	$ 900	$ 600
7	Allocation to distribution (Labor ratio)	85.75%	85.75%	85.75%	85.75%	85.75%
8	Allocation to D.C. (Labor ratio)	43.59%	43.55%	43.57%	43.50%	44.10%
9	Adjustment to D.C. distribution O&M expense	$ -	$ -	$ 299	$ 336	$ 227
10	Adjustment to D.C. income tax expense	$ -	$ -	$ (69)	$ (118)	$ (109)
11	Adjustment to Federal income tax expense	$ -	$ -	$ (162)	$ (276)	$ (255)
	Total Earnings	**$ -**	**$ -**	**$ (609)**	**$ (1,036)**	**$ (957)**
	Rate Base					
12	Adjustment to average D.C. distribution electric plant in service	$ -	$ -	$ 1,358	$ 4,102	$ 5,489
13	Adjustment to D.C. distribution accumulated amortization	-	-	(271)	(1,088)	(2,182)
14	Adjustment to D.C. distribution net plant	$ -	$ -	$ 1,087	$ 3,014	$ 3,307
15	Adjustment to accumulated deferred income tax	$ -	$ -	$ (50)	$ (200)	$ (400)
	Total Rate Base	**$ -**	**$ -**	**$ 1,037**	**$ 2,814**	**$ 2,907**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 17 - Reflection of Regulatory Asset for COVID-19 Related Costs		HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings						
1	COVID Costs Deferred Balance - Actual through October 2021	$ 12,746					
2	Adjustment to Amortization Expense (5 year amortization period)		$ -	$ -	$ 2,549	$ 2,549	$ 2,549
3	Adjustment to D.C. Income Tax Expense		-	-	(210)	(210)	(210)
4	Adjustment to Federal Income Tax Expense		-	-	(491)	(491)	(491)
	Total Earnings		**$ -**	**$ -**	**$ (1,848)**	**$ (1,848)**	**$ (1,848)**
	Rate Base						
5	Average DC regulatory asset balance	$ 12,746					
6	Decline in balance After Year 1	(1,275)					
7	Total average unamortized rate base balances		$ -	$ -	$ 11,471	$ 8,922	$ 6,373
8	Adjustment to accumulated deferred income taxes		-	-	(3,157)	(2,455)	(1,754)
9	Adjustment to rate base, net of accumulated deferred taxes		-	-	8,314	6,467	4,619
	Total Rate Base		**$ -**	**$ -**	**$ 8,314**	**$ 6,467**	**$ 4,619**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 18 - Reflection of Real Estate & Facility Costs	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings					
1	Electric Plant in Service	$ -	$ -	$ -	$ -	$ 21,225
2	Allocation to distribution (Labor Ratio)	85.75%	85.75%	85.75%	85.75%	85.75%
3	Allocation to D.C. (Plant less AFUDC ratio)	51.41%	52.04%	52.12%	52.40%	52.66%
4	Adjustment to D.C. electric plant in service	$ -	$ -	$ -	$ -	$ 9,585
5	Adjustment to D.C. depreciation expense	-	-	-	-	495
6	Adjustment to D.C. Income Tax Expense	-	-	-	-	(41)
7	Adjustment to Federal Income Tax Expense	-	-	-	-	(95)
	Total Earnings	**$ -**	**$ -**	**$ -**	**$ -**	**$ (359)**
	Rate Base					
8	Adjustment to average D.C. distribution electric plant in service	$ -	$ -	$ -	$ -	$ 4,779
9	Adjustment to average D.C. distribution accumulated depreciation	-	-	-	-	(248)
10	Average Net Plant	$ -	$ -	$ -	$ -	$ 4,531
11	Accumulated Deferred Income Tax	-	-	-	-	19
	Total Rate Base	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4,550**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 19 - DER Interconnection	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings					
1	Electric Plant in Service	$ -	$ -	$ 11,439	$ 11,439	$ 11,439
2	Allocation to distribution (Labor Ratio)	85.75%	85.75%	85.75%	85.75%	85.75%
3	Allocation to D.C. (Plant less AFUDC ratio)	51.41%	52.04%	52.12%	52.40%	52.66%
4	Electric Plant in Service (IT) - DC Distribution	$ -	$ -	$ 5,112	$ 5,140	$ 5,166
5	Adjustment to Amortization Expense (5 year)	$ -	$ -	$ 1,022	$ 1,028	$ 1,033
6	Adjustment to O&M expense	$ -	$ -	$ 512	$ -	$ -
7	Allocation to distribution (Labor ratio)	85.75%	85.75%	85.75%	85.75%	85.75%
8	Allocation to D.C. (Labor ratio)	43.59%	43.55%	43.57%	43.50%	44.10%
9	Adjustment to D.C. distribution O&M expense	$ -	$ -	$ 191	$ -	$ -
10	Adjustment to D.C. Income Tax Expense	-	-	(100)	(85)	(85)
11	Adjustment to Federal Income Tax Expense	-	-	(234)	(198)	(199)
	Total Earnings	**$ -**	**$ -**	**$ (879)**	**$ (745)**	**$ (749)**
	Rate Base					
12	Adjustment to average D.C. distribution electric plant in service	$ -	$ -	$ 2,556	$ 5,126	$ 5,153
13	Adjustment to D.C. distribution accumulated amortization			(510)	(1,532)	(2,559)
14	Net DC distribution plant	$ -	$ -	$ 2,046	$ 3,594	$ 2,594
15	Accumulated Deferred Income Tax			(94)	(281)	(470)
	Total Rate Base	**$ -**	**$ -**	**$ 1,952**	**$ 3,313**	**$ 2,124**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 20 - EDIT Balance	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings					
1	5-Year Excess Deferred Income Tax Balance (Regulatory Asset) Non-Property Related (5 year amortization)	$ -	$ -	$ 750	$ 750	$ 750
2	Adjustment to Amortization expense	-	-	150	150	150
3	Adjustment to D.C. Income Tax Expense	-	-	(12)	(12)	(12)
4	Adjustment to Federal Income Tax Expense	-	-	(29)	(29)	(29)
	Total Earnings	**$ -**	**$ -**	**$ (109)**	**$ (109)**	**$ (109)**
	Rate Base					
5	DC Regulatory Asset Balance	$ -	$ -	$ 750	$ 750	$ 750
6	Decrease in balance due to amortization expense	-	-	(150)	(300)	(450)
7	Net Rate Base Impact - DC Regulatory Asset	$ -	$ -	$ 600	$ 450	$ 300
8	Average Rate Base	$ -	$ -	$ 300	$ 525	$ 375
9	Adjustment to accumulated deferred income taxes	-	-	(83)	(144)	(103)
10	Adjustment to rate base, net of accumulated deferred taxes	$ -	$ -	$ 217	$ 381	$ 272
	Total Rate Base	**$ -**	**$ -**	**$ 217**	**$ 381**	**$ 272**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 21 - House of Worship Credit		HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings						
1	House of Worship / Non-Profit Credit - Costs Incurred through December 2022	$ 57					
2	Add: Estimated Q1 2023 House of Worship Credit Costs	19					
3	Total Projected Costs	$ 76					
4	Adjustment to Amortization Expense (1 year amortization period)		$ -	$ -	$ 76	$ -	$ -
5	Adjustment to D.C. Income Tax Expense		-	-	(6)	-	-
6	Adjustment to Federal Income Tax Expense		-	-	(15)	-	-
	Total Earnings		**$ -**	**$ -**	**$ (55)**	**$ -**	**$ -**
	Rate Base						
7	Average DC regulatory asset balance	$ 76					
8	Decline in balance After Year 1	(38)					
9	Total average unamortized rate base balances		$ -	$ -	$ 38		$ -
10	Adjustment to accumulated deferred income taxes		-	-	(10)	-	-
11	Adjustment to rate base, net of accumulated deferred taxes		$ -	$ -	$ 28	$ -	$ -
	Total Rate Base		**$ -**	**$ -**	**$ 28**	**$ -**	**$ -**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 22 - Reflection of Current Case Costs		HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings						
1	Current Rate Case Costs Projection	$ 4,065					
2	Less: Refund of FCs 1139 and 1150 Rate Case Costs	(196)					
3	Subtotal: Rate Case Costs Projection	$ 3,869					
4	Adjustment to Amortization Expense (3 Year Amortization Period)		$ -	$ -	$ 1,290	$ 1,290	$ 1,290
5	Adjustment to D.C. Income Tax Expense		-	-	(106)	(106)	(106)
6	Adjustment to Federal Income Tax Expense		-	-	(249)	(249)	(249)
	Total Earnings		**$ -**	**$ -**	**$ (935)**	**$ (935)**	**$ (935)**
	Rate Base						
7	Average DC regulatory asset balance	$ 3,869					
8	Decline in balance after Year 1	(645)					
9	Total average unamortized rate base balances		$ -	$ -	$ 3,224	$ 1,934	$ 644
10	Adjustment to accumulated deferred income taxes		-	-	(887)	(532)	(177)
11	Adjustment to rate base, net of accumulated deferred taxes		$ -	$ -	$ 2,337	$ 1,402	$ 467
	Total Rate Base		**$ -**	**$ -**	**$ 2,337**	**$ 1,402**	**$ 467**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 23 - Reflection of Electric Vehicle Regulatory Asset	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings					
1	Electric Vehicle Costs Deferred Balance	$ 626	$ 2,047	$ 3,571	$ 3,571	$ 3,571
2	Adjustment to Amortization Expense (5 year amortization period)	-	-	714	714	714
3	Adjustment to D.C. Income Tax Expense	-	-	(59)	(59)	(59)
4	Adjustment to Federal Income Tax Expense	-	-	(138)	(138)	(138)
	Total Earnings	**$ -**	**$ -**	**$ (517)**	**$ (517)**	**$ (517)**
	Rate Base					
5	Electric Vehicle Costs Deferred Balance (Regulatory Asset)	$ 626	$ 2,047	$ 3,571	$ 3,571	$ 3,571
	Decrease in balance due to amortization expense	-	-	(714)	(1,428)	(2,142)
6	Net Rate Base Impact - DC Regulatory Asset	$ 626	$ 2,047	$ 2,857	$ 2,143	$ 1,429
7	Average Rate Base	$ -	$ -	$ 2,452	$ 2,500	$ 1,786
8	Adjustment to accumulated deferred income taxes	-	-	(675)	(688)	(491)
9	Adjustment to rate base, net of accumulated deferred taxes	$ -	$ -	$ 1,777	$ 1,812	$ 1,295
	Total Rate Base	**$ -**	**$ -**	**$ 1,777**	**$ 1,812**	**$ 1,295**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 24 - Small DER Cost Sharing Petition	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings					
1	D.C. Distribution Electric Plant in Service	$ -	$ -	$ 980	$ 1,960	$ 2,940
2	D.C. Small DER Regulatory Liability (Deferred Revenues)	-	-	(791)	(1,582)	(2,373)
3	Adjustment to Depreciation Expense	-	-	29	58	87
4	Adjustment to Amortization Expense - Reg Liability	-	-	(23)	(47)	(70)
5	Adjustment to D.C. Income Tax Expense	-	-	-	(1)	(1)
6	Adjustment to Federal Income Tax Expense	-	-	(1)	(2)	(3)
	Total Earnings	**$ -**	**$ -**	**$ (5)**	**$ (8)**	**$ (13)**
	Rate Base					
7	Adjustment to average D.C. distribution electric plant in service	$ -	$ -	$ 490	$ 1,470	$ 2,450
8	Adjustment to average D.C. distribution accumulated depreciation	-	-	(15)	(58)	(131)
9	Average Net Plant	$ -	$ -	$ 475	$ 1,412	$ 2,319
10	Adjustment to accumulated deferred income tax - net plant	-	-	(1)	(14)	(40)
11	Adjustment to average DC Regulatory Liability - Small DER	-	-	(396)	(1,187)	(1,978)
12	Adjustment to average D.C. distribution accumulated amortization	-	-	12	47	105
13	Adjustment to accumulated deferred income taxes	-	-	106	314	515
14	Adjustment to reg liability net of accumulated deferred taxes and accum. amortization	$ -	$ -	$ (278)	$ (826)	$ (1,358)
	Total Rate Base	**$ -**	**$ -**	**$ 196**	**$ 572**	**$ 921**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 25 - Adjustments to Depreciation Rates	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings					
1	Adjustment to DC Distribution Depreciation Expense	$ -	$ -	$ 11,921	$ 12,849	$ 13,659
2	Adjustment to D.C. Income Tax Expense	-	-	(983)	(1,060)	(1,127)
3	Adjustment to Federal Income Tax Expense	-	-	(2,297)	(2,476)	(2,632)
	Total Earnings	**$ -**	**$ -**	**$ (8,641)**	**$ (9,313)**	**$ (9,900)**
	Rate Base					
4	Adjustment to average DC Distribution Accumulated Depreciation	$ -	$ -	$ (5,904)	$ (18,278)	$ (31,553)
5	Average Rate Base	-	-	(5,904)	(18,278)	(31,553)
6	Adjustment to accumulated deferred income taxes			1,625	5,030	8,683
7	Adjustment to rate base, net of accumulated deferred taxes			(4,279)	(13,248)	(22,870)
	Total Rate Base	**$ -**	**$ -**	**$ (4,279)**	**$ (13,248)**	**$ (22,870)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 29 - Reflection of Capital Project Updates	HTY 12 ME December 31, 2022	Bridge Year 12 ME December 31, 2023	MYP Year 1 12 ME December 31, 2024	MYP Year 2 12 ME December 31, 2025	MYP Year 3 12 ME December 31, 2026
	Earnings					
1	Adjustment to DC Depreciation Expense	$ -	$ (5)	$ (96)	$ (230)	$ (631)
2	Adjustment to DC Amortization Expense	-	(140)	(413)	(414)	(414)
3	Adjustment to DC Income Tax expense	-	12	42	53	86
4	Adjustment to Federal Income Tax expense	-	28	98	124	201
	Total Earnings	**$ -**	**$ 105**	**$ 369**	**$ 467**	**$ 758**
	Rate Base					
5	Adjustment to average DC distribution electric plant in service	$ -	$ (792)	$ (5,045)	$ (9,685)	$ (23,312)
6	Adjustment to DC distribution accumulated depreciation	-	2	33	196	644
7	Adjustment to DC distribution accumulated amortization	-	46	346	760	1,175
8	Net DC distribution plant	**$ -**	**$ (744)**	**$ (4,666)**	**$ (8,729)**	**$ (21,493)**
9	Accumulated Deferred Income Tax	-	8	66	153	240
	Total Rate Base	**$ -**	**$ (736)**	**$ (4,600)**	**$ (8,576)**	**$ (21,253)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 30 - Removal of DC CREF Meters	HTY 12 ME December 31, 2022	Bridge Year 12 ME December 31, 2023	MYP Year 1 12 ME December 31, 2024	MYP Year 2 12 ME December 31, 2025	MYP Year 3 12 ME December 31, 2026
	Earnings					
1	Adjustment to DC Depreciation Expense	$ -	$ -	$ (54)	$ (54)	$ (54)
2	Adjustment to DC Income Tax expense	-	-	4	4	4
3	Adjustment to Federal Income Tax expense	-	-	11	11	11
	Total Earnings	**$ -**	**$ -**	**$ 39**	**$ 39**	**$ 39**
	Rate Base					
4	Adjustment to average DC distribution electric plant in service	$ -	$ -	$ (649)	$ (649)	$ (649)
5	Adjustment to DC distribution accumulated depreciation	-	-	269	323	377
6	Net DC distribution plant	$ -	$ -	$ (380)	$ (326)	$ (272)
7	Accumulated Deferred Income Tax	-	-	77	76	68
	Total Rate Base	**$ -**	**$ -**	**$ (303)**	**$ (250)**	**$ (204)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

(Thousands of Dollars)

Line No.	Adjustment 31 - Removal of Benning RI/FS Regulatory Asset & Amortization (Order 21884)	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
	Earnings					
1	Adjustment to amortization expense - Remove Benning RA amortization	$ -	$ (329)	$ (329)	$ (329)	$ (329)
2	Adjustment to D.C. income tax expense	-	27	27	27	27
3	Adjustment to Federal income tax expense	-	63	63	63	63
	Total Earnings	**$ -**	**$ 239**	**$ 239**	**$ 239**	**$ 239**
	Rate Base					
4	Removal of Benning Regulatory Asset (RI/FS Costs through Dec 2017), Average	$ (2,507)	$ (2,343)	$ (2,014)	$ (1,684)	$ (1,355)
5	Adjustment to Accumulated Deferred Income Taxes	690	645	554	463	373
	Total Rate Base	**$ (1,817)**	**$ (1,698)**	**$ (1,460)**	**$ (1,221)**	**$ (982)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Interest Synchronization of Unadjusted Cost of Service
Multi-Year Plan

(Thousands of Dollars)

Line No.	Per Book Interest Sync	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year 1 12 ME Dec 31, 2024	MYP Year 2 12 ME Dec 31, 2025	MYP Year 3 12 ME Dec 31, 2026
1	Unadjusted D.C. income tax expense for the twelve months ended December 31,	$ (20,274)	$ 5,542	$ 6,632	$ 5,667	$ 3,742
2	Unadjusted D.C. portion of Federal income tax expense for the twelve months ended December 31,	$ 1,902	$ 3,195	$ (828)	$ (3,969)	$ (8,466)
3	Unadjusted Average D.C. Rate Base	$ 2,510,235	$ 2,753,106	$ 2,993,051	$ 3,222,775	$ 3,412,556
4	Weighted Cost of Debt @ December 31,	2.31%	2.35%	2.47%	2.48%	2.49%
5	Pro-forma interest on Average D.C. Rate Base	57,986	64,698	73,928	79,925	84,973
6	less: Per Book D.C. Interest Expense	$ 67,039	$ 79,129	$ 89,353	$ 94,675	$ 99,865
7	Adjustment to D.C. Interest Expense for Interest Synchronization	$ (9,053)	$ (14,431)	$ (15,425)	$ (14,750)	$ (14,892)
8	Adjustment to Unadjusted D.C. Income Tax Expense for pro-forma interest expense	$ 747	$ 1,191	$ 1,273	$ 1,217	$ 1,229
9	Adjustment to Unadjusted D.C. Federal Income Tax Expense for pro-forma interest expense	$ 1,744	$ 2,780	$ 2,972	$ 2,842	$ 2,869
10	Unadjusted D.C. income tax reflecting synchronization of interest with unadjusted rate base (line 1 + line 8)	$ (19,527)	$ 6,733	$ 7,905	$ 6,884	$ 4,971
11	**Unadjusted D.C. portion of federal income tax reflecting synchronization of interest with unadjusted rate base (line 2 + line 9)**	**$ 3,646**	**$ 5,975**	**$ 2,144**	**$ (1,127)**	**$ (5,597)**

POTOMAC ELECTRIC POWER COMPANY

Computation of District of Columbia Tax, Allocation & Other Factors
Multi-Year Plan

Line No.	Description		Statutory Tax Rate
1	D.C. Franchise Tax Rate		8.250%
2	Federal Income Tax Rate		21.00%

Line No.	Description	Computation	Tax Factor
3	D.C. Franchise Tax Factor	line 1	8.25000%
4	Federal Income Tax Factor	(100% - (line 3)) x line 2	19.26750%
5	Complement of Composite Tax Factor	100% - (line 3 + line 4)	72.48250%
6	Tax Conversion Factor	1/ line 5	1.379643362

Capital Structure:

Dec 31, 2022

Type of Capital	Amount	Ratio	Cost %	Weighted %
long term debt	3,719,941,424	49.32%	4.690%	2.31%
common equity	3,782,532,123	50.68%	9.275%	4.70%
total	7,502,473,546	100%		
ROR at Authorized ROE				**7.01%**

Dec 31, 2023

Type of Capital		Ratio	Cost %	Weighted %
long term debt		49.32%	4.77%	2.35%
common equity		50.68%	9.275%	4.70%
total	-	100%		
ROR at Authorized ROE				**7.05%**

Dec 31, 2024

Type of Capital	Ratio	Cost %	Weighted %
long term debt	49.50%	4.99%	2.47%
common equity	50.50%	10.50%	5.30%
total	100%		
ROR at Proposed ROE			**7.77%**

Dec 31, 2025

Type of Capital	Ratio	Cost %	Weighted %
long term debt	49.50%	5.02%	2.48%
common equity	50.50%	10.50%	5.30%
total	100%		
ROR at Proposed ROE			**7.78%**

Dec 31, 2026

Type of Capital	Ratio	Cost %	Weighted %
long term debt	49.50%	5.04%	2.49%
common equity	50.50%	10.50%	5.30%
total	100%		
ROR at Proposed ROE			**7.79%**

Other Factors:

Allocation Factors	
Labor ratio - 2022	85.75%
Distribution-Related Allocation Factors	
Plant less AFUDC	0.8237
Depr Exp Less AFUDC	0.9075

DC Jurisdictional Allocation Factors

	2022	2023	2024	2025	2026
O&M less A&G, and Storm Costs	0.4358951	0.4355	0.4357	0.4350	0.4410
Average & Excess-Subtr	0.4031	0.4031	0.4031	0.4031	0.4031
Plant less AFUDC	0.5141	0.5204	0.5212	0.5240	0.5266
Depr less AFUDC	0.5533	0.5578	0.5559	0.5590	0.5611
Accum Depr less AFUDC	0.4707	0.4756	0.4807	0.4855	0.4905

Effective Tax Rate	
FIT Rate (Statutory rate)	0.210000
DCIT Rate (Statutory rate)	0.082500
FIT Effective Rate (based on Statutory rate)	0.192675
Effective Tax Rate (based on Statutory rates)	0.275175

R.T. Leming
Rebuttal Testimony Exhibit
DC P.S.C. - - February 27, 2024

Introduced as:
PEPCO _________(3B) - 2

Potomac Electric Power Company
District of Columbia
Multi-Year Plan

Line No.	Revenue Requirement Impact of COVID-Impacted BSA Regulatory Asset Proposal	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year (1) 12 ME Dec 31, 2024	MYP Year (2) 12 ME Dec 31, 2025	MYP Year (3) 12 ME Dec 31, 2026
	(Thousands of Dollars)					
1	**Average Net Rate Base Adjustment**	**$ -**	**$ -**	**$ 44,468**	**$ 39,787**	**$ 35,106**
2	Amortization Expense Adjustment	-	-	4,681	4,681	4,681
3	Total State and Federal Tax Expense (at 27.5175% composite rate)	-	-	(1,288)	(1,288)	(1,288)
4	**Operating Income Adjustment**	**$ -**	**$ -**	**$ (3,393)**	**$ (3,393)**	**$ (3,393)**
5	Proposed ROR	7.01%	7.05%	7.77%	7.78%	7.79%
6	Tax Conversion Factor	1.37964	1.37964	1.37964	1.37964	1.37964
7	**Proposed Revenue Requirement Adjustment**	**$ -**	**$ -**	**$ 9,448**	**$ 8,952**	**$ 8,454**
8	Rebuttal Revenue Requirement - PEPCO (3B)-1	$ (14,958)	$ 28,064	$ 116,266	$ 150,736	$ 186,488
9	**Revenue Requirement with COVID-Impacted BSA Regulatory Asset**	**$ (14,958)**	**$ 28,064**	**$ 125,714**	**$ 159,688**	**$ 194,942**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia Distribution
Ratemaking Adjustment Calculation
Multi-Year Plan

Income Tax Rates:	
DC Tax Rate	8.25%
Federal Tax Rate	21%
Tax Conversion Factor	1.37964

(Thousands of Dollars)

Line No.	Reflection of COVID-Impacted BSA Regulatory Asset (Informational)	HTY 12 ME Dec 31, 2022	Bridge Year 12 ME Dec 31, 2023	MYP Year (1) 12 ME Dec 31, 2024	MYP Year (2) 12 ME Dec 31, 2025	MYP Year (3) 12 ME Dec 31, 2026
	Earnings					
1	Adjustment to amortization expense (10 year amortization period)	$ -	$ -	$ 4,681	$ 4,681	$ 4,681
2	Adjustment to D.C. income tax expense	-	-	(386)	(386)	(386)
3	Adjustment to federal income tax expense	-	-	(902)	(902)	(902)
	Total Earnings	**$ -**	**$ -**	**$ (3,393)**	**$ (3,393)**	**$ (3,393)**
	Rate Base					
4	COVID-Impacted BSA Regulatory Asset	$ -	$ -	$ 46,809	$ 44,468	$ 39,787
5	Average decline in balance from amortization	-	-	(2,341)	(4,681)	(4,681)
6	Rate Base impact of current period amortization	$ -	$ -	$ 44,468	$ 39,787	$ 35,106
	Total Rate Base	**$ -**	**$ -**	**$ 44,468**	**$ 39,787**	**$ 35,106**

APPENDIX B

PROPOSED FINDINGS OF FACT AND
CONCLUSIONS OF LAW

1. Pepco's has met its burden and established that the proposed three-year MYP, the Climate Ready Pathway, is reasonable and is appropriately adopted as an alternative form of regulation for the Company.

2. Pepco's proposed MYP satisfies the requirements of Section 34-1504(d)(2) of the District of Columbia Official Code as it: (a) will protect customers; (b) will ensure the quality, availability, and reliability of regulated electric services in the District of Columbia; and (c) is in the interest of the public, including shareholders of the Company.

3. Pepco's proposed MYP is consistent with the framework approved in the AFOR Order and will result in benefits to customers, the District of Columbia, other stakeholders and the Company.

4. Pepco's proposed MYP strikes the appropriate balance between the Company's requirements to offer reliable services at just and reasonable rates, and providing a climate ready pathway as a foundation to support the District's climate goals.

5. Pepco has established that it will have a revenue deficiency of $116.3 million in MYP Year ("MYPY")1, $34.5 million in MYPY2 and $34.8 million in MYPY3.

6. Pepco's proposed ratemaking adjustments to the MYP are reasonable, appropriate and authorized.

7. Pepco's proposed overall rates of return of 7.77%, 7.78% and 7.79% for MYPYs 1, 2 and 3, respectively, are reasonable and appropriate.

8. The Company's proposed capital structure of long-term debt of 49.5% and common equity of 50.5%, for each year of the MYP, is reasonable and in accordance with Commission precedent.

9. The Company has appropriately determined its cost of debt of 4.99% for MYPY1; 5.02% for MYPY2; and 5.04% for MYPY3 in accordance with Commission precedent.

10. Pepco's use of a 10.5% cost of common equity for purposes of the proposed MYP is reasonable and the Company is therefore authorized to earn 10.5% as its cost of common equity during the term of the proposed MYP.

11. Pepco's authorized return on equity of 10.5% should not be adjusted as a result of the adoption of the proposed MYP.

12. Pepco's Distribution Construction Program, as found at PEPCO (H)-1 through (H)-3, is reasonable and in compliance with prior Commission directives.

13. The Company's use of its Long Range Plan as the basis for the proposed MYP projections, is reasonable and appropriate.

14. The Company's projected O&M costs for each year of the MYP are reasonable and appropriate.

15. Pepco's Bill Stabilization Adjustment Mechanism ("BSA") is reasonable, meets the objectives as established by the Commission, and shall be continued.

16. Pepco shall recover any remaining BSA deferral balances associated with the FC 1150 settlement Normalization Adjustment through the normal operation of the BSA.

17. Pepco shall recover any remaining BSA deferral balances associated with the FC 1150 demand billing determinant error, which had resulted in under-recoveries of authorized revenues, through the normal operation of the BSA.

18. The proposal advanced by AOBA and OPC that a portion of the BSA deferral balance be recovered through a regulatory asset is reasonable. Pepco's proposal that $46.8 million of the current Schedule GT LV BSA deferral balance related to declining energy usage during the COVID-19 pandemic therefore be recovered outside of the BSA through a regulatory asset, with a return at the Company's approved rate, is reasonable and is approved.

19. Pepco's proposed enhancements to the BSA in connection with the MYP (i.e., use of a revenue target per class; annual reconciliation and surcharge; use of a demand charge component for demand metered classes; and display of the BSA surcharge as a separate line item on bills) are reasonable and shall be adopted; and Pepco is directed to file the necessary tariff change pages to reflect these modifications.

20. Pepco's proposed enhancement to the Residential Aid Discount program to allow categorical eligibility is reasonable and is approved and Pepco is directed to file an implementation plan with the Commission.

21. Pepco's proposed enhancement to the Arrearage Management Program is reasonable and is approved and Pepco is directed to file an implementation plan with the Commission.

22. Pepco's proposed new time-of-use ("TOU") rates for residential customers (Schedule R TOU), and TOU electric vehicle charging rates for demand-metered commercial customer classes, are reasonable and therefore adopted. The Company will file the necessary tariff pages to reflect these new rates as well as an implementation plan with the Commission.

23. Pepco's updated billing determinants for the MYP are reasonable.

24. Pepco's bill impact analyses are reasonable.

25. The PHI Service Company costs and Exelon Business Services Company costs charged to

Pepco and allocated to the District of Columbia are reasonable and were allocated in accordance with the applicable cost allocation manual.

26. Pepco's proposed Income Tax Adjustment Rider for the purpose of recovering or refunding the revenue requirement associated with Federal or District of Columbia statutory corporate income tax rate changes is reasonable and is approved.

27. Pepco has appropriately reflected the Federal corporate alternative minimum tax in the MYP.

28. Pepco's reliance on the outcome of the PIMs Working Group process for development of PIMs for inclusion in future proceedings is reasonable.

29. The proposed MYP's Deferred Accounting Mechanism is reasonable and is approved.

30. The proposed MYP's Re-Opener provision is reasonable and is approved.

31. The proposed MYP's Annual Information Filing is reasonable and is approved.

32. The proposed MYP's Consolidated Reconciliation and Prudency Review process is reasonable and is approved.

33. The proposed MYP's Final Reconciliation and Prudency Review process is reasonable and is approved.

34. Pepco's Jurisdictional Cost of Service Study for distribution service is reasonable and is accepted.

35. Pepco's Customer Class Cost of Service Study is reasonable and is accepted.

36. Pepco's proposed rate designs for each District of Columbia rate class are reasonable and are accepted.

37. The rates established under the MYP are just and reasonable and are approved.

38. Pepco's Depreciation Study is reasonable, consistent with Commission precedent and is approved.

39. Pepco's Lead Lag Study provides a reasonable basis for the calculation of the Company's proposed Cash Working Capital Allowance and is approved.

40. Pepco's Appliance Saturation Study and Conditional Demand Analysis are reasonable and have been appropriately used in this proceeding.

41. Pepco shall not be required to file a Distribution Marginal Cost Study in future rate proceedings.

CERTIFICATE OF SERVICE

I hereby certify that a copy of Potomac Electric Power Company's Post Hearing Brief has been served via email on this August 30, 2024 on:

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Public Service Commission
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