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ORDER NO. 89868

Potomac Electric Power Company's Application for an Electric Multi-Year Rate Plan	* * * * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9655

ORDER ON APPLICATION FOR MULTI-YEAR RATE PLAN

Before: Jason M. Stanek, Chairman
Michael T. Richard, Commissioner
Anthony J. O'Donnell, Commissioner
Odogwu Obi Linton, Commissioner
Mindy L. Herman, Commissioner

Issued: June 28, 2021

APPEARANCES

Kim F. Hassan, Douglas E. Micheel, and Matthew K. Segers, Esquire for Potomac Electric Power Company

Lloyd J. Spivak, Michael A. Dean, Kenneth Albert and James Gregor for *Maryland Public Service Commission Staff*

David S. Lapp, William F. Fields, Anna Ryon, Gary L. Alexander and Jacob M. Ouslander for *Maryland Office of People's Counsel*

Frann G. Francis, Nicola Whiteman and Excetral Caldwell for *Apartment and Office Building Association*

Kristi Singleton for *U.S. General Services Administration*

Lisa Brennan for *Montgomery County, Maryland*

James K. McGee of the Law Office of Robert R. Castro for *Prince George's County, Maryland*

Brian R. Greene and Laura E.K. Musick of GreeneHurlocker, PLC and Suellen M. Ferguson of Baradel, Kosmerl and Nolan, P.A. for *Town of Kensington, Maryland*

Suellen M. Ferguson, Baradel, Kosmerl and Nolan, P.A. on brief for *Chevy Chase Village, Town of Chevy Chase and Section 3 of the Village of Chevy Chase*

Ronald M. Bolt, Bolt Legal, LLC on Comments for *Town of Chevy Chase View, Maryland*

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I. INTRODUCTION AND EXECUTIVE SUMMARY

1. On February 4, 2020, the Commission issued Order No. 89482 ("MRP Pilot Order") in Case No. 9618,[1] establishing a framework for a Multi-year Rate Plan ("MRP") Pilot. In the MRP Pilot Order, the Commission approved a pilot process allowing electric and gas utilities in Maryland to request a rate plan using a multi-year period. The Commission found that a multi-year rate plan—if properly designed and implemented—could provide several benefits, including more predictable rates for customers and more predictable revenues for utilities.

2. Additionally, the Commission found that by spreading rate changes over multiple years, multi-year rate plans could reduce the burden on rate case participants by staggering complex rate case applications over several years.[2] The Commission noted, however, that at the end of the pilot, the Commission would review its experience with the pilot multi-year rate plan and identify any lessons learned from the process.[3] The Commission noted that the first utility to file a multi-year plan request, which happened to be Baltimore Gas and Electric Company ("BGE"), would be the test case for the pilot process. The Commission issued its Order on the BGE Pilot Application for a Multi-Year Rate Plan on December 16, 2020.[4]

3. Despite the Commission's desire for a "lessons-learned" analysis following the issuance of the BGE MPR Order, and the opportunity to develop regulations governing Alternative Form of Regulation ("AFOR") utility multi-year plan requests, the MRP Pilot

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[1] *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*, Case No. 9618, Order No. 89482 (Order Establishing Multi-Year Rate Plan - Pilot) (Feb. 4, 2020).
[2] Order No. 89482 at 1, 8 and 37.
[3] Order No. 89482 at 13.
[4] *In the Matter of the Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan*, Order No. 89678 ("BGE MRP Order") (Dec. 16, 2020).

Order did not preclude the filing of the multi-year request made by Potomac Electric Power Company ("Pepco") before the BGE MRP Order issued.

Pepco's Application

4. On October 26, 2020, Pepco ("the Company") filed an Application with the Commission seeking an MRP,[5] requesting an increase in electric rates to be effective November 25, 2020.[6] In its Application, Pepco proposed a three-year MRP covering the three-year period of April 1, 2021 through March 31, 2024. The costs in the proposed MRP include investments made since the last base rate case and forecasted to be made through March 31, 2024. The Company projected that it would spend approximately $259 million in 2020 and $1.09 billion over the four-year calendar period 2021-2024 on upgrades and improvements to Pepco's Maryland distribution system.[7]

5. Additionally, Pepco included in its Application a plan to convert company-owned street lights throughout the Pepco service territory to light-emitting diode ("LED") street lights with smart nodes, and requested that the Commission allow the Company to record the operating and maintenance ("O&M") costs associated with deployment of its "Smart Streetlight Initiative" as a regulatory asset, to be amortized over a five–year period.[8]

6. Finally, in light of the impacts of the COVID-19 pandemic, Pepco's request included a proposal to accelerate certain tax benefits and to pause amortization expenses

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[5] The acronym "MRP" refers to a multi-year rate plan, as discussed and approved for a pilot in Commission Order No. 89482. Pepco has referred to its multi-year rate plan as an "MYP." For purposes of consistency and to avoid confusion, this Order will use the single term: MRP.

[6] The Commission docketed Pepco's Application as Case No. 9655 and issued Order No. 89660, initially suspending the proposed new rates pursuant to *Annotated Code of Maryland*, Public Utilities Article ("PUA") § 4-204 for 150 days from November 25, 2020 and directing Pepco to publish a description of its Application in newspapers of general circulation in the company's service territory. The Commission revised the suspension period in Order No. 89687 to 180 days from December 30, 2020.

[7] In its Application, Pepco states that "new technology has been installed that enables the Company to provide more reliable service in a cost-effective manner." Pepco Application, Maillog No. 232316 at 2.

[8] Pepco Application, Maillog No. 232316 at 3.

that it stated would result in "no overall distribution rate increase for customers during the first two years" of its multi-year plan. Pepco proposed a partial offset to overall distribution rates in the third year of the plan.[9] Thus, under Pepco's plan, the Company projected that customers would see "no overall distribution rate increase until April of 2023."[10]

7. The Commission has reviewed the evidence and testimony presented, including the comments received at the public hearings, in reaching the decisions in this Order. Based on the record, the Commission authorizes Pepco to increase its electric distribution rates for each year of the MRP, with offsets as described in this Order, as provided in the chart below:

Table 1
Authorized vs. Requested Revenue Requirement

Incremental Revenue Requirement	**Authorized**	**Pepco Requested**	**Bill Impact**
Yr1	$20,647,281	$37,437,000	$0.00
Yr2	$16,259,805	$35,436,000	To Be Determined
Yr3	$15,337,168	$31,186,000	To Be Determined
Total	**$52,244,253**	$104,059,000	

8. As a result of the COVID-19 pandemic, and consistent with the BGE MRP Order, the Commission is *accelerating* the return of certain customer monies to ensure that there is no bill impact to customers during 2021. The Commission will not at this time order the use of accelerated offsets to prevent an increase in customer bills in 2022. However,

[9] *Id*. at 4.
[10] *Id.*

this Order provides flexibility for the Commission to use additional offsets to reduce the impact of Pepco's rate increase in 2022, depending on the state of the economy, the nation's progress in battling COVID-19, and Pepco's revised work plans that will be contained in its 60-day report, discussed below.

9. The adjustments to Pepco's MRP request in this case yield an estimated effective per month bill impact – for a typical residential customer using 811 kWh per month during the MRP period – an increase of zero dollars in 2021, $3.66 in 2022, and $1.54 in 2023, as compared to the $5.50 increase in 2023 requested by Pepco.[11]

II. **BACKGROUND**

10. The Application was submitted by Pepco as the second pilot utility under the MRP Pilot Order. The Application was supported by the filing requirements approved by the Commission in the MRP Pilot Order and the Direct Testimonies of witnesses Kevin M. McGowan (Pepco Ex. 4), Tyler W. Wolverton (Pepco Ex. 21), Shelina H. Merchant (Pepco Ex. 24), Lance C. Schafer (Pepco Ex. 31), Peter R. Blazunas (Pepco Ex. 33),[12] Elizabeth M. D. O'Donnell (Pepco Ex. 10), Adrian M. McKenzie (Pepco Ex. 25), Phillip S. Barnett (Pepco Ex. 12), Robert S. Stewart (Pepco Ex. 15), Morlon D. Bell-Izzard (Pepco Ex. 19), Mark K. Warner (Pepco Ex. 38), and David S. Schatz (Pepco Ex. 27).

11. The Commission docketed Pepco's Application on October 26, 2020 as Case No. 9655 and issued a Revised Procedural Schedule in Order No. 89687, pursuant to the Joint Request by Pepco and Commission Staff ("Staff") to Extend the Procedural Schedule,

[11] Compare, Pepco Application at 4; McGowan Direct at 26.
[12] Mr. Blazunazs' Direct Testimony was adopted by Pepco witness Matthew K. Bonikowski. Maillog No. 233265.

suspending the proposed new rates pursuant to PUA § 4-204 for 150 days from December 30, 2020.[13]

12. The prehearing conference in this matter was conducted on November 23, 2020, at which the Commission granted the Petitions to Intervene of the following Parties: Apartment and Office Buildings Association ("AOBA"); U.S. General Services Administration ("GSA"); Montgomery County, Maryland; Town of Chevy Chase View, Maryland; Prince George's County, Maryland ("Prince George's"); and Town of Kensington, Maryland ("Kensington").[14]

13. Order No. 89687 set a revised procedural schedule, for the filing of testimony, hearings for cross-examination of witnesses, and the filing of briefs and reply briefs. The Order also set public comment hearings that were held on March 10, 2021 and April 15, 2021.[15]

14. On the scheduled filing date of March 3, 2021: Kensington filed the Direct Testimony of Scott Watson (Kensington Ex. 1);[16] Prince George's filed the Direct Testimony of Gwendolyn Clerkley (Prince George's Ex. 1); Staff filed the Direct Testimonies and Exhibits of Drew M. McAuliffe (Staff Ex. 1), David Hoppock (Staff Ex. 20), Felix L. Patterson (Staff Ex. 18), Anna Joy Harris (Staff Ex. 30), Roger F. Austin (Staff Ex. 26), Zhuoqun Jiang (Staff Ex. 28 and Ex. 28C), and Huilan Li (Staff Ex. 23 and 23C); AOBA filed the Direct Testimonies of Timothy B. Oliver (AOBA Ex. 1) and

[13] In its Initial Procedural Schedule in Order No. 89660, the Commission established the deadline for filing petitioners to intervene and scheduled a virtual prehearing conference.
[14] Notice of the Commission's Pre-hearing Conference was published by Pepco in newspapers of general circulation in Pepco's service territory as noted in Pepco's Certificate of Publication filed November 20, 2020. Pepco Ex. 1 (Maillog No. 232572).
[15] Notices of the Commission's Public Hearings were published by Pepco in newspapers of general circulation in Pepco's service territory as noted in Pepco's Certificates of Publication filed March 17, 2021 and April 14, 2021. Pepco Ex. 2 (Maillog No. 234234) and Ex. 3 (Maillog No. 234776).
[16] The Town of Chevy Chase View also filed the Direct Testimony of witness Scott M. Watson.

Bruce R. Oliver (AOBA Ex. 3); and the Maryland Office of People's Counsel ("OPC") filed the Direct Testimonies of Jerome D. Mierzwa (OPC Ex. 1), Courtney Lane (OPC Ex. 2), Melissa Whited (OPC Ex. 4), Paul J. Alvarez and Dennis Stephens ("Alvarez-Stephens") (OPC Ex. 6 and Ex. 6C), David J. Effron (OPC Ex. 8), and Dr. J. Randall Woolridge (OPC Ex. 10).

15. On March 31, 2021, the Parties filed rebuttal testimonies as follows: Pepco filed the Rebuttal Testimonies of Kevin McGowan (Pepco Ex. 7), J. Tyler Anthony (Pepco Ex. 9), Elizabeth M.D. O'Donnell (Pepco Ex. 11), Phillip S. Barnett (Pepco Ex. 13), Dr. Ekaterina Efimova (Pepco Ex. 14), Robert Stewart (Pepco Ex. 15), Morton D. Bell-Izzard (Pepco Ex. 20), Tyler W. Wolverton (Pepco Ex. 23), Adrian M. McKenzie (Pepco Ex. 26), David S. Schatz (Pepco Ex. 28), David K. Pickles (Pepco Ex. 30), Lance K. Schafer (Pepco Ex. 32), and Matthew K. Bonikowski (Pepco Ex. 35); Kensington filed the Rebuttal Testimonies of Scott Watson and Matt Hoffman (Kensington Exs. 2 and 3); Prince George's filed Rebuttal Testimony of Gwendolyn Clerkley (Prince George's Ex. 2); and Staff filed the Rebuttal Testimonies of David Hoppock (Staff Ex. 21) and Anna Joy Harris (Staff Ex. 31); AOBA filed the Rebuttal Testimony of Bruce R. Oliver (AOBA Ex. 5).

16. On April 20, 2021, the following Parties filed surrebuttal testimonies: Pepco filed Surrebuttal Testimonies of Kevin McGowan (Pepco Ex. 8) and David S. Schatz (Pepco Ex. 29), Prince George's filed Surrebuttal Testimony of Gwendolyn Clerkley (Prince George's Ex. 2); OPC filed the Surrebuttal Testimonies of Courtney Lane (OPC Ex. 3), Melissa Whited (OPC Ex. 5), Alvarez-Stephens (OPC Ex. 7), and Dr. J. Randall

Woolridge (OPC Ex. 11); and AOBA filed the Surrebuttal Testimonies of Timothy B. Oliver (AOBA Ex. 2) and Bruce R. Oliver (AOBA Ex. 6).

17. A trial-type evidentiary hearing was held on April 26 – 30, 2021. At the hearing, all pre-filed testimonies were admitted into evidence; Pepco was allowed to present live rejoinder testimony to other Parties' witnesses.

18. Following the evidentiary hearings, in addition to the briefs filed by the Parties, on May 21, 2021, Chevy Chase Village, Town of Chevy Chase View and Section 3 of the Village of Chevy Chase (together the "Chevy Chase Municipalities") filed a Motion for Authorization to File an Amicus Brief. In their Motion, the Chevy Chase Municipalities noted that they are three small municipalities in Montgomery County, Maryland who have an interest in preserving their ability to purchase and maintain their own street lights. Finding that the Chevy Chase Municipalities' views in this case merit consideration, the Commission grants the Motion and accepts the Amicus Brief of the Chevy Chase Municipalities as part of this proceeding.

III. DISCUSSION AND FINDINGS

A. Revenue Requirement and Adjustments

Pepco Direct

19. Pepco presented a total of 36 Rate Making Adjustments ("RMA") with 19 based on the historical test year ("HTY").[17] Even though Pepco's MRP included projected costs for which it was not seeking recovery, those items must be removed through a RMA. Pepco witness Tyler W. Wolverton explained there were three categories of

[17] Wolverton Direct at 23-24.

RMAs based on HTY adjustments that were not applicable to the forecasted years. First, the removal of non-recurring costs in the HTY, which do not need to be adjusted in the MRP because the costs are not in the bridge/MRP period.[18] Second, the annualization of revenue/costs changes in the HTY which are already factored into the projected revenues and costs in the bridge/MRP, such as rate case expenses from Case No. 9602. Finally, the normalization of HTY costs that are used to smooth fluctuations in actual costs but do not need to be adjusted in the MRP because the MRP uses projected costs.

20. After the filing of all testimony, many of the RMAs were no longer contested. However, Staff and OPC both made further adjustments as discussed below. The Parties' final positions with respect to additional revenues to be afforded Pepco are summarized in this chart:[19]

Table 2
Revenue Requirement Comparison by Party

	2022	**2023**	**2024**
Pepco	$37,437,000	$72,783,000	$104,059,000
OPC	$5,740,000	$19,284,000	$32,695,000
Staff	$19,596,000	$46,902,000	$68,765,000

Other Parties' (Staff, OPC and AOBA) Positions

21. Staff, OPC and AOBA propose to eliminate recovery of significant amounts of Pepco's forecasted capital expenditures including several capital projects – some of

[18] The bridge year ended March 31, 2021, and the MRP is a three-year period that will begin with the issuance of this Order and end in 2024.
[19] These figures are cumulative and do not include proposed offsets to the revenue requirement. *See,* RMA 33 – Proposed Offsets.

which are part of ongoing programs projects that are already under construction, projects for which construction has not begun, and contingencies included in the Company's forecasted spend. Pepco proposes to continue rebuilding its 69kV feeders at an estimated cost of $595.7 million and then fund three separate substation projects with an estimated cost of $248.8 million over the MRP.[20] OPC recommended the removal of $645.6 million from Pepco's proposed capital spending over the course of the MRP, including the 69kV Feeder Rebuild, 13kV Underbuild Program, and the substation projects. Staff recommended the removal of approximately $93 million of capital expenditures, including amounts related to the Company's 69kV Feeder Rebuild and 13kV Underbuild Programs, as well as approximately $35.5 million in capital project contingencies.

22. Additionally, AOBA generally objected to any increase, but should the Commission award Pepco an increase, recommended that it be no more than $55.05 million for the duration of the three-year plan and be spread evenly at $18.35 million per year. AOBA stated that its recommendation "would adhere to gradualism, avoid rate shock, eliminate the need to defer revenues beyond the proposed [MRP] period, improve ratepayers' ability to plan and budget for rate increase, and would help simplify any future reconciliations …"[21]

Pepco Rebuttal

23. Pepco witness Wolverton asserted there were errors in AOBA witness Timothy Oliver's revenue requirement calculations. He claimed AOBA failed to provide support for the unadjusted rate base amounts that AOBA witness Oliver relied on and that he

[20] Staff asserted that the cost of the 69kV Feeder Rebuild was $653.6 million. See, Austin Direct - Revised at 25, *citing* Pepco's response to Staff Data Request No. 35-25.
[21] T. Oliver Direct at 37 and TBO-6.

used inconsistent rate base amounts.[22] Pepco witness Wolverton also asserted AOBA incorrectly applied the tax gross-up factor and, when corrected, AOBA's proposed revenue requirement would increase by approximately $15 million. Based on discovery responses, Pepco witness Wolverton found AOBA's unadjusted rate base calculations, which included a return on equity (ROE), to be completely arbitrary and produced a $98 million downward adjustment.[23] He claimed the adjustment lacked any rationale or explanation, the calculation was based on the Company's balance sheet in which ROE was not a factor, and AOBA double-counted the impact of its proposed ROE.[24]

24. In response to OPC and Staff, Pepco witness Wolverton found both Messrs. Effron and Patterson made common errors that resulted in significantly overstating reductions to electric plant in service ("EPIS") and their recommended revenue requirements. He found both OPC and Staff relied on capital expenditures rather than plant closings. Pepco witness Wolverton testified, "EPIS is made up of plant closings, not capital expenditures, and as such, any adjustment to EPIS must be based on plant closings."[25]

25. Next, Pepco witness Wolverton claimed OPC and Staff both disregarded "any and all allocations of project costs between transmission and distribution, and allocations between the District of Columbia (DC) and Maryland (MD)."[26] He noted the Company included only the Maryland portion (58.41%) of the projected plant closings in its

[22] Wolverton Rebuttal at 27.
[23] *Id.* at 30-31.
[24] *Id.* at 31.
[25] *Id.* at 5. Mr. Wolverton noted both OPC and Staff agreed with his assessment.
[26] Wolverton Rebuttal at 5. Again, Mr. Wolverton noted both OPC and Staff agreed with his assessment.

revenue requirement, but OPC and Staff removed 100% of the costs from EPIS and the revenue requirements.[27] Specific adjustments and projects are addressed below.

1. <u>COVID-19 Regulatory Asset</u>

<u>Pepco</u>

26. Pepco requested the inclusion in rate base and amortization of a regulatory asset to recover COVID-related costs over a five-year period. Pepco witness Wolverton testified that Pepco established a regulatory asset on March 13, 2020 pursuant to Case No. 9639.[28] He explained the Company sought to recover incremental lost late payment revenues, incremental lost connection and reconnection fees, pandemic-related incremental costs associated with personal protective equipment ("PPE"), cleaning, and other costs offset by lower meals, travel, and entertainment costs. In relation to the lost late payment revenues, connection, and reconnection fees, Pepco witness Wolverton used the amounts currently in customers' rates per Case No. 9602.[29] He stated, "With regard to incremental personal protective equipment, cleaning and other costs, unique project codes were created to track and categorize COVID-19 incremental costs."[30] The Company included actual costs through June 30, 2020 and projected incremental costs through December 31, 2020.[31]

27. Pepco included cost offsets in the regulatory asset. The Company established a baseline for travel, meals, and entertainment costs by calculating the monthly average for those costs currently in rates per Case No. 9602, and then compared the baseline to the

[27] *Id.* at 5-6.
[28] Wolverton Direct at 41-42, *citing State of Emergency and Public Health Emergency in the State of Maryland Due to COVID-19,* Order No. 89542 (April 9, 2020).
[29] Wolverton Direct at 42.
[30] *Id.*
[31] *Id.* at 45.

actual costs from April 2020 to June 2020. Pepco witness Wolverton found a significant cost decrease and those incremental savings represented an offset to COVID-19 related expenses included in the regulatory asset.[32]

28. The Company's incremental bad debt expense was estimated to be $1.8 million through June 30, 2020, which represented the potential incremental write-offs that will occur in the future due to COVID-19.[33] Pepco witness Wolverton noted that the Company's disconnection fees were close to zero due to the moratorium, but it was anticipated that the net write-offs would increase once the disconnection process resumed. He requested Commission approval of Pepco's methodology for calculating incremental uncollectible expenses for the COVID-19 regulatory asset. Further, he advised that the Company would track and report on the incremental COVID-19 costs over the next several years, and that any COVID-related costs incremental to RMA 31 that occur during the MRP be recovered in Pepco's next rate case filing.[34]

AOBA

29. AOBA witness Timothy Oliver found the COVID-19 adjustment to be inappropriate and ran counter to how regulatory assets are treated.[35] He testified, "The ongoing nature of the COVID-19 pandemic and the lack of Commission determinations regarding what costs are eligible or the appropriate amortization period render Pepco's proposed RMA 31 at best premature."[36]

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[32] *Id.* at 43.
[33] *Id.* at 44.
[34] *Id.*
[35] T. Oliver Direct at 35.
[36] *Id.*

OPC

30. OPC witness Effron recommended that lost revenues and expense savings related to COVID-19 not be included in rate base, consistent with the Commission's decision in Case No. 9645. He recommended reductions in rate base by $818,000, $636,000, and $455,000 for the years ending March 31, 2022, 2023 and 2024, respectively.[37] In surrebuttal, OPC witness Effron's adjustment eliminated COVID-19 lost revenues and expense savings from the Company's rate base, consistent with the Commission's directive in Case No. 9645.[38]

31. In its brief, OPC continued to support its position based on the Commission's finding in Case No. 9645 where it specified, "that lost revenues and savings not be included in rate base" and instead remain in a regulatory asset.[39]

Staff

32. Staff witness Patterson similarly proposed that the unamortized portion of the lost revenues (late payments and reconnection fees) not be included in rate base and not earn a return.[40] He noted that a regulatory asset usually consists of actual costs that have been incurred by the utility and, in contrast, the Company's lost revenues are estimated. Staff witness Patterson recommended an adjustment to rate base of $2,061,957,000 in MRP 2022, $2,246,205,000 for MRP 2023, and $2,337,155,000 for MRP 2024, respectively.[41]

33. In surrebuttal testimony, Staff witness Patterson reiterated that regulatory assets typically include costs incurred by a utility and that the COVID-19 lost revenues and

[37] Effron Direct at 11 and Ex. DJE-1, Schedule B.
[38] Effron Surrebuttal at 7 and Ex. DJE-2, Schedule B.
[39] OPC's Initial Brief at 8, *quoting* Order No. 89678 at 20, para. 43.
[40] Patterson Direct at 18.
[41] *Id.* at 9, and Ex. FP-1.

savings are estimated. He recommended not including the unamortized portion of the savings in rate base as a reduction for consistency purposes.[42] Furthermore, since Pepco was authorized to resume terminations and charge late fees effective October 1, 2020, Staff witness Patterson did not believe it was appropriate to include lost revenues in the regulatory asset for the months of November and December 2020.[43]

34. In its brief, Staff noted its adjustment was consistent with Order No. 89678 and that lost revenues should not be included in a regulatory asset. In its reply brief, Staff claimed its position was consistent with Case No. 9645, and argued that lost revenues for November and December 2020 should not be placed into the regulatory asset.[44]

Pepco

35. Pepco witness Wolverton disagreed with OPC and Staff's recommendations which he found to be arbitrary. He explained that lost revenues have the same impact on operating income as increased incremental costs; therefore, the Company should be permitted to earn a return on increased costs due to the COVID-19 pandemic and they should have the same treatment as lost revenues due to the pandemic.[45]

36. In response to AOBA, Pepco witness Wolverton disagreed that costs have not yet been incurred. In his Direct Testimony, Mr. Wolverton noted that the Company provided actual COVID-19-related costs through June 2020 with a projection for the remainder of 2020 and that those figures were updated.[46] He added that pursuant to Order No. 89542, the Company included its incremental COVID-19 related costs in a regulatory asset.

[42] Patterson Surrebuttal at 4.
[43] *Id.* at 5.
[44] Staff Reply Brief at 7.
[45] Wolverton Rebuttal at 12.
[46] *Id.* at 13.

Pepco witness Wolverton also cited to Case No. 9645 where the Commission authorized BGE's request to establish a regulatory asset for the recovery of actual COVID-19 costs, net of savings and governmental financial benefits or assistance over a five-year period.[47]

37. In its brief, Pepco argued that lost revenues have the same impact on operating income as increased incremental costs and are a real cost caused by COVID-19.[48] The Company should be permitted to earn a return on lost revenues as it is permitted to earn a return on increased costs. Pepco cited Case No. 9207 as precedent, in which the Commission permitted the Company to establish a regulatory asset for incremental costs associated with the Advanced Meter Infrastructure ("AMI") deployment that would be offset by known and quantifiable AMI-related cost savings, and Case No. 9418 in which the Commission authorized recovery of the AMI regulatory asset including a rate base return.[49]

38. In its reply brief, Pepco averred that if it can earn a return on increased costs from the pandemic, it should also be permitted to earn a return on lost revenues. The Company found AOBA's position to be contrary to Order No. 89542, in which the Commission granted the utilities the authority to create a regulatory asset to record COVID-19 incremental costs and found that the deferral of those costs were appropriate.[50]

<u>Commission Decision</u>

39. In Order No. 89542, the Commission permitted utilities to establish a regulatory asset to record incremental COVID-19-related costs and determined that deferring such

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[47] *Id.* at 13-14, *citing* Order No. 89678 at 19-20.
[48] Pepco Initial Brief at 44.
[49] *Id.* at 44, fn. 207, *citing Re Potomac Elec. Power Co.* Case No. 9207, Order No. 83571 at 52 (September 2, 2010) and *Re Potomac Elec. Power Co.*, Case No. 9418, Order No. 87884 at 39 (November 15, 2016).
[50] Pepco Reply Brief at 24.

costs is appropriate based on the catastrophic health emergency that was outside the utilities' control and was a non-recurring event.[51] Furthermore, the Commission found it appropriate to begin amortization of the COVID-19 regulatory asset in 2021 rather than 2023.[52] Additionally, in the Pilot MRP, the Commission authorized BGE:

> To establish a regulatory asset for the recovery of actual incremental COVID-19 costs, net of savings and any financial benefits or assistance provided by any level of government related to COVID-19 relief, over a five-year period beginning in 2023. The Commission directs that lost revenues and savings not be included in rate base, ….[53]

40. Rather than follow the framework in the Pilot MRP Order established in December 2020, Pepco essentially argued that the Commission's finding on this issue was wrong and that it should be permitted to include lost revenues in its COVID regulatory asset. While parties are free to make proposals that may be contrary to previous Commission orders, such proposals should be supported with reasoning why a precedent should be changed.

41. In this case, the Commission finds no reason to depart from our recent ruling in Case No. 9645. Therefore, the Commission agrees with OPC and Staff and grants authority to Pepco to establish a regulatory asset for the recovery of actual incremental COVID-19 costs, net of savings and any financial benefits or assistance provided by any level of government related to COVID-19 relief, over a five-year period beginning in 2023. The Commission further directs that lost revenues and fees are not included in rate base and that the COVID-19 regulatory asset will begin amortization in the year 2021 rather than 2023. Finally, the Commission directs Pepco to use the methodology

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[51] Order No. 89542; *see also* Order No. 89678 at 19-20.
[52] Order No. 89678 at 20.
[53] *Id.*

approved in Order No. 89678 for calculating incremental write-offs related to the COVID-19 pandemic, by recording the difference between the levels of monthly write-offs to the monthly uncollectible write-offs in the historical test year from the Company's last rate case.

2. RMA 32 – Smart LED Streetlighting Initiative[54]

Pepco

42. Pepco witness David S. Schatz provided details about Pepco's proposed Smart LED ("light-emitting diode") Streetlight Initiative ("SLED" or "Initiative"), which involves converting all Pepco-owned overhead non-LED streetlights to LED fixtures coupled with smart node technology—totaling approximately 66,300 fixtures.[55] In conjunction with the Initiative, Pepco also proposes to implement a two-year Smart Sensor Pilot Program to deploy and assess the benefits and functionality of third-party commercial sensors.

43. Witness Schatz explained that the goal of the Initiative is to provide energy-efficient, enhanced, smart LED street light technology throughout the Pepco service territory, for the benefit of municipalities.[56] He testified that Pepco proposes to offer its customers 26 different LED streetlight options to choose from for installation, consisting of nine styles of LED lights with equivalent wattages ranging from 50 – 400.[57] Mr. Schatz stated that Pepco will also install smart nodes on all Company-owned LED

[54] Pepco submitted the Smart LED Streetlight Initiative and the Smart Sensor Pilot Program as two separate proposals in its MRP application. For purposes of this Order, the Commission will address the merits of both proposals in this RMA discussion.
[55] Schatz Direct at 2.
[56] *Id.* at 3.
[57] *Id.* at 7.

streetlights, which would function within the Company's existing AMI network.[58] He noted that the smart nodes would enable bi-directional communication of event and alarm information to Pepco's operation systems; enable dimming, adjusting scheduling for when lights are on or off, and other lighting functionalities; and provide for improved performance of the AMI mesh network by increasing the number of connection points throughout the Pepco service territory.[59]

44. Mr. Schatz also provided details on Pepco's proposed development and integration of a Central Management System ("CMS"), which involves integrating the CMS with multiple Pepco systems and applications to allow data flow from the smart nodes to Pepco through the AMI network.[60] Consequently, the CMS will allow Pepco to have "full visibility into the performance and health of each smart LED streetlight[,]" enabling real-time data access and more efficient, lower-cost maintenance.[61]

45. Pepco witnesses Schatz and Schafer both provided details on proposed costs. The estimated total cost of the Initiative is $67,060,928, which combines all streetlight conversions for Pepco MD and Delmarva MD.[62] Witness Schatz testified that Pepco proposes to recover the Company's cost to procure and install the LED fixtures through new rate structures for Streetlighting customers.[63] Witness Shafer added that the proposed LED streetlight rates were designed to include the installation costs of the LED fixtures in the customer's monthly fixed charge.[64] He explained that with the new rates for the LED streetlights, customers will no longer have to pay an upfront contribution in

[58] *Id.* at 3.
[59] *Id.*
[60] *Id.* at 4.
[61] *Id.*
[62] Schatz Direct, Schedule (DSS)-2 at 1.
[63] Schatz Direct at 19.
[64] *Id.* at 22.

aid of construction ("CIAC") to install new streetlight fixtures; instead, the cost will be paid monthly through the fixed monthly charge.[65] The new rates (shown in Schedule SSL-S-OH-LED) will remain the same for each rate year of the MRP.[66]

46. According to witness Schatz, the Company designed the new LED streetlight rates to be "in line" with customers' current monthly rates,[67] that are consistent with previous customer rates.[68] However, some customers may see a rate increase.[69] Mr. Schatz explained that for those customers, Pepco proposes to offset their increases with EmPOWER Maryland funding.[70] Specifically, the Company will assist eligible customers with applying for and obtaining EmPOWER Maryland funding, which would then be remitted to the Company.[71] In contrast to these class-specific fixed charges, Mr. Schatz stated further that the procurement, installation, integration costs, and CMS will be recorded in general plant accounts and allocated to all customer classes.[72]

47. Pepco witness Wolverton provided information on RMA 32 for the Smart LED Streetlight Initiative. He stated that Pepco's proposed RMA 32 would establish a regulatory asset to recover incremental up-front IT costs associated with the conversion to smart LED Streetlighting and assume an amortization period of five years.[73] Mr. Wolverton explained that the proposed RMA also includes ongoing net O&M savings related to the LED conversion as they are projected in the MRP period.[74] He stated that if

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[65] *Id.*
[66] *Id.* at 21-22.
[67] *Id.* at 19.
[68] *Id.*
[69] *See Id*.
[70] *Id.*
[71] *Id.* at 21.
[72] *Id.*
[73] Wolverton Direct at 46.
[74] *Id.*

Pepco's request is granted, Pepco proposes to defer the incremental costs associated with this pilot to a regulatory asset for recovery in a future rate case.[75]

48. Witness Schatz completed a cost benefit analysis that assumed costs for the initiative were shared between Pepco and Delmarva Power and determined the benefits were greater than the costs of the Initiative.[76] This analysis found that the benefit cost ratio was 1.02 between 2022 and 2040.[77]

49. With regard to the Smart Sensor Pilot Program ("Pilot"), Mr. Schatz testified that the proposed Pilot uses separate technology from the smart LED smart node but can also be affixed to the smart LED streetlights in the Initiative.[78] While the sensors are not components of the Initiative, they are designed to leverage the network connectivity of the smart nodes to provide customized community features to customers, such as air quality monitoring, traffic monitoring, and gunshot detection.[79] Mr. Schatz explained that the Company will evaluate two types of commercially available smart sensors, deploying up to 50 sensors in two Maryland communities.[80] According to witness Schatz, the goal of the Pilot is to test and develop business processes that would support a future offering of affordable and secure smart sensors for Pepco's streetlight customers.[81] Furthermore, "[d]eploying smart sensors using the Company's Smart LED streetlights would ensure the sensors can operate on the Company's secure network and can meet

[75] *Id.*
[76] Schatz Direct at 13.
[77] Schatz Direct, Schedule (DSS)-2 at 2.
[78] Schatz Rebuttal at 3.
[79] *Id.* at 3-4.
[80] Schatz Direct at 16.
[81] *Id.*

cybersecurity procedures."[82] He emphasized that Pepco is not proposing any tariff modifications for the Pilot and has no transition plan at this time.[83]

50. Witness Schatz explained that Pepco proposes to implement the Pilot and the Smart LED Streetlight Initiative concurrently in order to respond to customer interest and develop future offerings.[84] He stated that Pepco would locate two community partners to participate in the Pilot upon the Commission's approval of the project.[85] According to witness Schatz, Pepco estimated a total cost of $1.8 million for the Pilot, and it involves three parts: (1) procurement of the equipment and vendor support; (2) incremental costs to support information technology testing and provisioning: and (3) incremental costs for Pepco's engineering and customer groups to support development of new business process and customer support materials.[86] Witness Schatz noted that Pepco seeks to defer these Pilot costs to a regulatory asset for consideration in a future base rate case.[87]

Staff

51. While Commission Staff supported Pepco's proposal to replace non-LED streetlights with LED street lights, Staff witness Zhuoqun Jiang challenged and adjusted several assumptions from Pepco's cost-benefit analysis.[88] Witness Jiang challenged the following Pepco assumptions: (1) that the average cost of a call to a call center is $31.47 per call; (2) that 100 percent of customer calls would be eliminated under the Initiative due to the smart nodes; (3) using an average of Pepco and Delmarva data to estimate the number of cancelled streetlight orders per fixture; and (4) using one year of data to

[82] Schatz Rebuttal at 3.
[83] *Id.*
[84] Schatz Direct at 17-18.
[85] *Id.*
[86] *Id.* at 18.
[87] *Id.* at 20.
[88] Jiang Direct at 16-19.

average baseline assumption data.[89] He modified these assumptions by assuming: (1) that the average cost of a call to a call center is $15.74; (2) that 90 percent of customer calls would be eliminated under the Initiative due to the smart nodes; (3) averages of some baseline assumptions using data from 2016-2019; and (4) the use of only Pepco data for the average number of cancelled streetlight orders.[90] Using these adjustments, Witness Jiang estimated a societal cost test value ("SCT") ranging from 1.02 - 1.05, which is lower than Pepco's SCT of 1.07.[91] He also estimated the proposal's impact on customer bills. His analysis found a cost benefit ratio in a range of 0.96 - 0.98, meaning that customers will experience an increase in their monthly bills.[92]

52. Witness Jiang conducted other sensitivity analyses for the proposed initiative, including a total resource cost test ("TRC") which included all assumptions except for air emissions benefits and a different discount rate.[93] Witness Jiang estimated a TRC between 0.73 – 0.74 depending upon whether Pepco's assumptions or his assumptions were used.[94] He also performed an analysis to determine the cost effectiveness of the Initiative without the smart nodes. To accomplish this, he removed all benefits except those associated with reducing watts related to high-pressure sodium (HPS) to LED conversions and varying costs attributable to the Initiative due to the smart nodes using all Pepco assumptions.[95] Witness Jiang's estimated results range from 0.87 – 1.02 under a societal cost test.[96]

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89 *Id.* at 16-18
90 *Id.* at 19, Table 3.
91 *Id.*
92 Jiang Direct at 22.
93 *Id.* at 21.
94 *Id.* at 21-22.
95 *Id.* at 20.
96 *Id.* at 20, Table 4.

53. Witness Jiang's final recommendation is that Pepco's Smart LED Streetlight Proposal be determined to be cost effective using the societal cost test, but not cost effective using the total resource cost test.[97] He also recommended that the Commission use his Cost Benefit Analysis model assumptions.[98]

54. Mr. Jiang further recommended that the Commission not approve Pepco's proposal to use EmPOWER Maryland funds to offset the bill increases because the streetlights are not owned by the customers, and the customer has no choice in whether to accept or reject a streetlight change, since all streetlights would be upgraded.[99] Effectively the customer does not have the ability to "reject" the change in utility-owned streetlights.[100] He stated that Pepco's proposal amounts to a request for EmPOWER Maryland funds to be "ultimately paid to the utility for streetlight upgrades."[101] Witness Jiang also points out that another utility in Maryland, Potomac Edison, already offers a streetlight program where the costs are recovered outside of EmPOWER Maryland.[102]

55. Staff witness Anna Joy Harris recommended that Pepco only be allowed to recover costs up to Pepco's current estimated costs of the streetlight initiative, and that any actual costs above Pepco's estimate not be allowed recovery.[103]

56. Witness Harris stated that while Staff agreed with Pepco's proposed rates for the LED streetlights, Pepco calculated its proposed rates based on its requested ROE of 10.2 percent. She recommended that if the Commission approves the proposed Smart LED

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[97] *Id.* at 24.
[98] *Id.*
[99] *Id.* at 23.
[100] *Id.*
[101] *Id.*
[102] *Id.*
[103] Harris Direct at 30-31.

Streetlight Initiative, Pepco be required to recalculate the LED rates based on the Commission's approved ROE.[104]

57. Witness Harris raised a concern that customers could request installation of new, non-LED streetlights prior to the approval of the Company's Initiative and pay a CIAC upfront, only to have their lamps replaced by LED lamps under the Company's proposed initiative, within a short period of time.[105] She noted that the customer would then be required to pay another installation charge through rate base.[106]

58. According to Ms. Harris, Staff does not support the Company's proposed Smart Sensor Pilot, stating that it does not serve a distribution function, and its costs should not be recovered through rate base.[107] She recommended that if the Commission approves the Smart Sensor Pilot, the Commission should require Pepco to fund the pilot without imposing program costs on ratepayers.[108]

59. In sum, Ms. Harris recommended that the Commission accept the proposed Smart LED Streetlight Initiative at Pepco's estimated costs and disallow recovery of actual costs of the streetlight initiative above the estimated costs and reject the proposed Smart Node Pilot Program.[109]

Town of Chevy Chase View

60. The Town of Chevy Chase View opposed the proposed LED rate structure as not just and reasonable and noted that the Town incurred significant costs in purchasing its

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[104] Harris Direct at 33. In his Rebuttal, Pepco witness Schafer agreed with Staff's recommendation on this point, i.e., to immediately close the Company-owned non-LED light schedules to new installation, to avoid confusion. Schafer Rebuttal at 9.
[105] *Id.*
[106] *Id.*
[107] *Id.* at 34.
[108] *Id.*
[109] *Id.*

current, functioning lights.[110] Town witness Scott M. Watson stated that the mandatory replacement of the Town's streetlights under the Company's Initiative would be premature and force the replacement of existing luminaires with non-equivalent, inferior lights.[111] He explained that under the Initiative, the Town would have to pay a higher tariff for LED lights than what it has been paying for its current induction lights, which according to Mr. Watson do not need replacing.[112] Witness Watson added it would constitute a windfall for Pepco by allowing the Company to retain $34,000 in unused and already paid maintenance fees.[113] Mr. Watson also noted that the installation of a smart system would not materially benefit the Town.[114]

Town of Kensington

61. Witness Scott Watson also provided testimony on behalf of the Town of Kensington opposing Pepco's streetlight Initiative, stating that the proposal with its smart node system was of uncertain benefit to the Town, and that the Town did not know enough about the smart node proposal to support it.[115] Mr. Watson opined that the Initiative is not an upgrade and that it would not result in either lower costs or justifiably higher costs to the Town.[116] He testified that Pepco's LED light offerings are unlikely to improve the Town's lighting, arguing instead that the one-for-one replacement of old lights with new lights could, in fact, exacerbate existing problems arising from lighting layout.[117]

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[110] Watson (Chevy Chase View) Direct at 7.
[111] *Id.* at 3.
[112] *Id.*
[113] *Id.*
[114] *Id.* at 8.
[115] *Id.* at 8-9.
[116] *Id.* at 3.
[117] *Id*.

62. Witness Watson testified that Pepco should not be allowed to install any LED replacement fixtures in the Town until the Company has satisfied specific conditions, including displaying its LED offerings in a demonstration facility, and permitting the Town and its consultant to evaluate and select appropriate offerings for use in the Town.[118] Mr. Watson requested that the Town of Kensington be placed late in Pepco's installation schedule to allow more time for the Town to consider potentially acceptable luminaire options,[119] and he objected to the installation of any "smart" equipment without the Town Council's approval.[120]

63. Additionally, Witness Watson raised the concern that despite Pepco's proposal to replace all existing streetlights with new LED lights at "no cost" to the municipalities involved, the monthly tariffs for the new LED fixtures would be higher than the current tariffs for existing luminaires.[121] He objected to the fact that the higher tariffs have no sunset provisions, stating it would be unfair for Pepco to continue charging inflated tariffs after the Town has paid for the LED installation.[122] To that end, Mr. Watson recommended that Pepco be required to provide a sunset date for the initial tariff for the LED replacement fixtures. Thereafter, the tariff should be lowered based on anticipated maintenance and repair costs.[123] Witness Watson did not address the Smart Sensor Pilot in his Direct Testimony.

[118] Watson (Kensington) Direct at 5.
[119] *Id.* at 6.
[120] *Id.* at 9.
[121] *Id.* at 6.
[122] *Id.* at 6-7.
[123] *Id.* at 7.

Prince George's County

64. Prince George's County supported the LED replacement proposal for energy efficiency reasons, and because the initiative facilitated a more expeditious conversion than otherwise would be made possible because of upfront costs.[124] Direct Witness Gwendolyn Clerkley stated that the County supported the smart node pilot under the conditions that the cost should be substantially reduced, or the sensors installed and the number of communities served be substantially increased.[125] She also recommended that Pepco should coordinate and seek approval from the counties regarding the communities chosen for the pilot, the technology features, and the data to be tracked.[126] She further recommended that the data should be provided to the County or the communities served on a real-time basis.[127]

Parties' Rebuttal Positions

Pepco

65. Pepco witness Schatz filed rebuttal testimony in response to various parties' direct testimony related to the proposed Initiative. Witness Schatz disagreed with Staff witness Harris's recommendation to cap recoverable costs at the Company's estimated costs.[128] He argues that Pepco could possibly identify more than the estimated 66,000 streetlights for conversion through a field survey, though witness Schatz claims Pepco will not include costs associated with requested new streetlights in the cost of the program.[129] He also disagrees with Witness Jiang's position against the use of the EmPOWER funds for

[124] Hoffman Direct at 3.
[125] *Id.* at 6.
[126] *Id.*
[127] *Id.*
[128] Schatz Rebuttal at 5.
[129] *Id.* at 6-7.

the Initiative. Witness Schatz disagrees with Witness Jiang's assessment that EmPOWER funds are "typically used to incentivize participants in purchasing more efficient measures."[130] In response to Staff witness Jiang's position that customers cannot reject a change in streetlights, Witness Schatz claims customers have a choice during the streetlight conversion to choose between nine different LED styles and, after accounting for different wattage types and styles, a total of 26 choices.[131] He also disagreed with Witness Jiang's concern about using EmPOWER funds for non-customer owned measures citing the combined heat and power ("CHP") programs where the facility is financed and not owned by the customer.[132]

66. Witness Schatz also attempted to respond to various criticisms and comments regarding customer preferences and choices for the proposed Initiative and Smart Sensor Pilot. Witness Schatz disagreed with Prince George's County's recommendation that Pepco be required "to 'seek approval' on the deployment schedule from the County."[133] He also provided various plans for how Pepco will engage with stakeholders, accommodate deployment schedule requests, provide two demonstration sites, attempt to provide new lights if requested, and will not convert existing LEDs to new LEDs though Pepco plans to "attach a smart node to customer's existing LED lights."[134] He also claimed Pepco "has no preference for higher temperature LED and selected 3000 Kelvin

[130] *Id.* at 7.
[131] *Id.* at 9.
[132] *Id.* at 9-10.
[133] *Id.* at 10-11.
[134] *Id.* at 11-13.

temperature for all proposed LED streetlights" and that they plan to offer adequate shielding.[135]

67. Witness Schatz disagreed with Staff's recommendation to reject the Smart Sensor Pilot, claiming that it can provide community benefits and provides a way to learn about data delivered through AMI regarding community interest areas. He also agreed with Prince George's County Witness Clerkley that data gained from smart sensors benefits the County and helps the County make informed planning and safety response decisions.[136]

68. Witness Schafer filed rebuttal testimony stating that Pepco agreed with Ms. Harris' recommendations that Pepco immediately close its Company-owned non-LED light schedule to new installations if the initiative is approved (referencing Schedule SSL-OH), and that Pepco be required to update the rates on proposed Schedule SSL-S-OH-LED to reflect the eventual Commission-authorized Return on Equity.[137] He stated further that Pepco agreed to Mr. Hoppock's recommended updates to Pepco's Terms of Service 4 and 7, for proposed Schedule SSL-OH-LED, and the updates were included in Pepco witness Bonikowski's rebuttal testimony.[138] Witness Schafer did not agree with any of the municipalities' findings and recommendations in his rebuttal testimony. However, he stated that, in response to the testimony of Prince George's County, customers can request new LED streetlights and poles for additional locations, and they would be eligible for the rates on the proposed Schedule SSL-S-OH-LED.[139]

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[135] *Id.* at 12-13.
[136] *Id.* at 15.
[137] *Id.* at 9.
[138] *Id.* at 11.
[139] *Id.* at 18.

69. Pepco witness David K. Pickles filed rebuttal testimony that predominantly addressed Staff witness Jiang's direct testimony related to modified assumptions in the cost benefit analysis for the Initiative.[140] Pepco witness Pickles accepted Staff Witness Jiang's proposal to: (1) "use five year averages instead of 2018 actuals for certain assumptions"; (2) use Pepco data only, instead of an average of Pepco and Delmarva Power data for certain assumptions; and (3) assume call-center calls for streetlight outages decrease by 90 percent instead of 100 percent.[141] Pepco witness Pickles accepted Staff witness Jiang's proposal to modify the cost of customer calls associated with streetlights, but not the amount of the proposed modification.[142] With these modifications, Pepco's calculated benefit cost ratio using the SCT is 1.0438 instead of 1.0656.[143] He also claims that if more LED streetlights are installed than the projected 66,000, he believes the proposed Initiative will be even more cost effective because a large portion of the costs are fixed.[144]

Staff

70. Staff witness Harris provided rebuttal testimony, summarizing and responding to the direct testimonies of Prince George's County witness Clerkley and Town of Chevy Chase View/Town of Kensington witness Watson. She recommended that the Commission reject witness Watson's proposal regarding a sunset date for the portion of the new tariff's monthly fixed charge related to the costs for installing smart LED

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[140] Pickles Rebuttal at 1-4.
[141] *Id.* at 3.
[142] Staff witness Jiang reduced the cost to $15.74 per call but Pepco witness Pickles reduced the cost to only $25.41 per call. Pickles Rebuttal at 6-7.
[143] Pickles Rebuttal at 4.
[144] *Id.* at 7.

luminaires.[145] Where witness Watson expressed concern over potential over-recovery of these costs, witness Harris responded that her adjusted Class Cost of Service Study ("CCOS") and rate design methodologies address this concern.[146]

71. Witness Harris discussed witness Clerkley's proposal to potentially include in the conversion all County-owned streetlight structures in Pepco's streetlight Initiative,[147] but she acknowledged it was unclear whether the County specifically makes this request.[148] To the extent the County requests the conversion of County-owned streetlights as part of the Initiative, witness Harris opposed passing those costs onto other ratepayers.[149]

72. Where Ms. Clerkley and Mr. Watson expressed interest in working with Pepco on the Initiative's installation process, witness Harris did not recommend that Pepco implement a unique LED streetlight solution for each municipality or county. If the Company can accommodate the Towns without passing on additional costs to other ratepayers, Staff would be supportive.[150] If the Town's request increases the costs of the Initiative, according to witness Harris, the individual local government causing the incremental cost increase should be responsible under the principle of cost causation.[151]

73. Staff witness Jiang provided surrebuttal testimony in response to the testimony of Pepco witnesses Schatz, Schafer, and Pickles. Witness Jiang agreed with the positions Mr. Schatz presented in his rebuttal testimony pertaining to the current annual savings goal of the EmPOWER program, the use of EmPOWER for programs deemed appropriate by the Commission, customers having the ultimate decision-making authority

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145 Harris Rebuttal at 12.
146 *Id.* at 12-13.
147 *Id.* at 2-3.
148 *Id.* at 3.
149 *Id.* at 13.
150 *Id.* at 15.
151 *Id.* at 15-16.

to choose the model and style of the proposed smart LED streetlight, and the existence of precedent for using EmPOWER funds to offset costs of LED streetlights for customer-owned streetlights.[152]

74. However, while witness Jiang acknowledged the precedent for the use of EmPOWER funds to offset customer-owned LED streetlight costs, he noted that in existing EmPOWER programs, customers can choose to upgrade their current streetlights to a more energy efficient streetlight, resulting in their eligibility to receive an incentive for upgrading.[153] He explained that Pepco's proposal only replaces Company-owned streetlights and not customer-owned streetlights, customers cannot keep their old HPS streetlights, and they can only decide on the model and style of the new smart LED streetlights.[154]

75. Mr. Jiang did not agree with witness Schatz's position that because the Proposal supports the EmPOWER goal of two percent savings, it justifies the use of EmPOWER funds for the streetlight proposal, stating that not all programs that contribute to the EmPOWER goal justify the use of EmPOWER funds.

76. Also, Mr. Jiang did not totally agree with Mr. Schatz that providing EmPOWER funds for the Proposal will incentivize customers to adopt smart LED technology, stating that the customer does not have a choice in whether their current HPS streetlight is replaced with a smart LED streetlight, and regardless of whether EmPOWER funds are

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152 Jiang Surrebuttal Testimony at 5-8.
153 *Id.* at 8.
154 *Id.*

used for the proposal, customers will be required to upgrade their HPS streetlight to a smart LED streetlight.[155]

77. Witness Jiang agreed with Pepco witness Pickles' changes to the assumptions in the BCA model, as Mr. Jiang had recommended the same changes in his direct testimony.[156]

78. He also agreed with Mr. Pickles that the assumed cost of a customer call related to a streetlight issue is estimated at $25.41.[157] He further agreed with Mr. Pickles that these changes to the assumptions in the BCA model would still result in a SCT ratio greater than 1, stating that with the assumptions, the SCT ratio would be approximately 1.04.[158]

79. Witness Jiang agreed with Mr. Pickles that, all else being equal, introducing additional streetlight conversions above the Company's estimated 66,000 conversions would positively impact the SCT, noting that the average cost of the fixed costs will decrease since additional streetlights are being converted, leading to a higher SCT ratio.[159]

80. Finally, Mr. Jiang agreed with Kensington witnesses Watson and Hoffman that some assumptions made in Pepco's BCA model are incorrect and should be corrected.[160]

Town of Kensington

81. Matt Hoffman provided rebuttal testimony in response to Staff Witnesses Jiang and Harris, and Prince George's County Witness Clerkley.[161] Mr. Hoffman noted in response to Ms. Harris' testimony that an estimated 77 percent of streetlight conversions

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[155] *Id.*
[156] *Id.*
[157] *Id.*
[158] *Id.* at 9.
[159] *Id.*
[160] *Id.* at 10.
[161] Hoffman Rebuttal at 2.

would result in a rate increase; the Town was also concerned about a potential increase.[162]

82. He stated that the Town agreed with her recommendation that if the Commission approves the streetlight initiative, Pepco should only be permitted to recover costs up to the utility's current estimated costs of the initiative and that recovery of actual costs above Pepco's estimate should be disallowed.[163]

83. According to Mr. Hoffman, Kensington generally agrees that the smart sensor pilot should not be funded by ratepayers and that there was insufficient information to determine the benefits of such a program.[164] He also emphasized that in response to Ms. Clerkley's testimony pertaining to her data request and Pepco's response that it intended to select a community from Prince George's and Montgomery counties for the smart sensor pilot, Kensington did not want to serve as a site for either the Smart Streetlight Initiative or Smart Sensor Pilot Program.[165]

84. Mr. Hoffman stated that Kensington agreed with Prince George's County's position that the costs and benefits associated with the Smart Sensor Pilot Program should be clarified and properly submitted for further review prior to being approved.[166] He further agreed that the pilot program's proposed costs appeared to outweigh its benefits and echoed Ms. Clerkley's recommendations regarding consulting with the communities and sharing data.[167]

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[162] *Id.*
[163] *Id.* at 3.
[164] *Id.*
[165] *Id.*
[166] *Id.*
[167] *Id.* at 4.

85. Mr. Hoffman stated that he agreed with Mr. Jiang's testimony regarding the unique operating circumstances and needs of different communities and the potential for resulting differences in data. He indicated that there may not be a one-size-fits-all solution with respect to the pilot program.[168] Mr. Hoffman also agreed with Mr. Jiang's challenge of some of Pepco's assumptions, which he referred to as unrealistic.[169]

86. On behalf of Kensington, witness Watson provided a rebuttal amending his previous testimony to emphasize that, in light of Staff witnesses Harris' and Jiang's recommendations, there was no incentive for a community to accept the proposed LED conversions until Pepco could show that the conversions provide at least the same "visual comfort," lumen output, and beam configuration as the streetlights being replaced.[170] Until then, he stated the Town should be allowed to continue using all of its existing streetlights, with full maintenance by Pepco, under the present tariff.[171]

Parties' Surrebuttal Positions

Pepco

87. Pepco witness Schatz responded in his surrebuttal testimony to the recommendations proffered by Kensington witnesses Watson and Hoffman. First, with respect to Mr. Hoffman's concern about potential rate increases for Streetlighting service, witness Schatz stated the proposed use of EmPOWER Maryland funds, along with the savings from smart LED use, will result in monthly customer bills at or below what customers currently pay for each streetlight.[172] The use of EmPOWER funding in

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[168] *Id*. at 5
[169] *Id.*
[170] Watson Rebuttal at 2.
[171] *Id.* at 3.
[172] Schatz Surrebuttal at 2.

particular is intended to facilitate a seamless conversion to LED streetlights by offsetting any increases in customer monthly costs.[173] Furthermore, Pepco's new rate schedule offers "on-bill financing" to remove the existing upfront cost for streetlight conversion under Pepco's current LED tariff. Thus, customers can pay for the fixture over time and convert to LED lights "with no upfront cost."[174]

88. Next, witness Schatz responded to Kensington witness Watson's recommendation that Pepco display streetlight offerings at a demonstration facility, stating the Company will commit to establishing demonstration facilities in both Prince George's and Montgomery counties for at least one year.[175] Pepco will also agree to make streetlight fixture recommendations to customers similar to their current wattage-equivalent and style.[176] According to witness Schatz, customers will be able to accept Pepco's offering or select a different style and wattage, subject to applicable increases in cost of that selection. They will also be able to purchase Company-owned lights.[177]

89. Lastly, witness Schatz testified that Pepco's budget is designed for full-scale deployment of all Company-owned streetlights, and the Company's proposed offerings respond to a range of customers' current light styles and wattages.[178] Mr. Schatz explained the Company's deployment strategy "maximize[s] economical and logistical efficiencies to the benefit of all streetlight customers."[179] He stated that Pepco does not propose an opt-out to the Initiative, and allowing customers to decline conversion until

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[173] *Id.* at 2.
[174] *Id.* at 3.
[175] *Id.* at 4.
[176] *Id*. Witness Schatz maintained, however, that the Company's offerings of 3000 Kelvin temperature LEDs are consistent with American Medical Association guidelines. *Id.*
[177] *Id.* at 5.
[178] *Id.* at 6.
[179] *Id.* at 6-7.

Pepco can offer a suitable selection "would create significant complexities and inefficiencies on the deployment of the Initiative."[180]

<u>Staff</u>

90. Staff witness Jiang filed surrebuttal testimony in response to Pepco witness Schatz, Pepco witness Pickles, and Kensington witnesses Hoffman and Watson. Witness Jiang disagrees with Pepco witness Schatz's position that since the proposal furthers the two percent EmPOWER savings goal that it therefore justifies the use of EmPOWER funds. Witness Jiang points out that not all EmPOWER programs that contribute to the EmPOWER goal use EmPOWER funds—these programs include Conservation Voltage Reduction, Dynamic Pricing, Transformers, and Streetlight programs.[181] Witness Jiang also disagrees with Pepco witness Schatz's assessment that a customer's ability to choose the type of LED streetlight addresses his concerns that a customer can reject the program, since the benefit cost analysis assumes all Company-owned streetlights will be replaced.[182] He also disagrees with the assessment that customers are incentivized to choose LED streetlights, since the customer will have to upgrade their light even if the EmPOWER funds are not provided.[183] Witness Jiang also responded to Pepco witness Schatz's assessment that EmPOWER-funded programs do not require customer ownership. Witness Jiang points out that for the example used—CHP—that the EmPOWER funds go to the participant and not the utility; the customer has to apply for and be approved for the funds.[184] Witness Jiang did agree with Pepco witness Schatz that

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[180] *Id.* at 7.
[181] Jiang Surrebuttal at 5-6.
[182] *Id.* at 6.
[183] *Id.* at 6-7.
[184] *Id.* at 7.

precedent exists for using EmPOWER funds for customer-owned street lights, but points out that the EmPOWER program is for customer-owned, not utility-owned, streetlights and customers have a choice to participate.[185]

91. Staff witness Jiang agreed with the modified assumptions for the cost benefit analysis proposed by Witness Pickles.[186]

92. Staff witness Harris also filed surrebuttal testimony in response to Pepco witnesses Schafer and Schatz, and Kensington witnesses Watson and Hoffman. She generally reaffirmed her position that Pepco should not be allowed to recover costs associated with the Initiative that exceed the Company's estimated costs. She clarified that where Pepco could discover additional non-LED streetlights for conversion not included in current estimates, Pepco should be allowed to recover those additional costs, so long as the cost per lamp conversion does not exceed the Company's current per-lamp cost estimate.[187]

93. With regard to Pepco's new LED streetlight rates, witness Harris agreed with Pepco witness Schafer that: (1) the new rates should not be lowered after the Company has recovered its installation costs; and (2) the rates already include maintenance savings of LED lights.[188]

94. Witness Harris repeated her opposition to Pepco's Smart Sensor Pilot Program because the pilot fails to serve any distribution function.[189] Accordingly, Ms. Harris

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[185] *Id.* at 8.
[186] *Id.* at 9-10.
[187] Harris Surrebuttal at 9.
[188] *Id.* at 10-11.
[189] *Id.* at 13.

concluded those costs should not be recovered through rate base.[190] She stated further, "Should Pepco choose to pursue the proposed Smart Sensor Pilot Program, the Company should fund the pilot without imposing the costs of the program on ratepayers."[191]

Prince George's County

95. Prince George's County witness Clerkley submitted surrebuttal testimony that the County wants to ensure coordination between the County's current project to convert County-owned streetlights to LED with the proposed Initiative since the County does not have the funds to change all the County-owned street lights to LED.[192] She also clarified that the County wants the Initiative "expanded to include the lack of a CIAC for these new streetlights poles or other attachments as well, when such a new structure is required/requested.[193]

Comments in Lieu of Briefs

96. Montgomery County and the Town of Chevy Chase View filed comments in lieu of initial briefs, where they concurred with the concerns expressed previously by the other localities.

97. In its comments, Montgomery County stated that while the proposed initiative contains positive goals of energy efficiency and improved customer service, Montgomery County had some concerns about Pepco's initiative as proposed.[194] Chief among the County's concerns is the apparent lack of customer choice.[195]

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[190] *Id.* at 13.
[191] *Id.*
[192] Clerkley Surrebuttal at 1-2.
[193] *Id.* at 2.
[194] Montgomery County Comments at 12.
[195] *Id.*

98. Montgomery County urged the Commission to condition any approval on the ability of customers to choose to be a part of the streetlight conversion program and to be able to choose the style, wattage, and color temperature of the lights.[196] The County noted that under *Annotated Code of Maryland*, Local Government Article, § 1-1309 (Street lighting equipment), Customer Choice customers have the authority to purchase utility-owned lights, and according to Pepco witness Schatz's testimony, Pepco has acknowledged that customers will retain the ability to purchase Pepco-owned streetlights if the Initiative is approved.[197]

99. However, Montgomery County stated that while Pepco witness Schatz testified that proposed Schedule SSL-S-OH-LED will be revised to reflect customers' right to own their streetlights, the revision is still forthcoming.[198] Montgomery County added that despite Pepco's emphasis on customer choice, customers cannot choose a streetlight style or wattage choice beyond the nine lighting styles and various wattages Pepco has offered, to include color temperature considerations.[199]

100. The County also was critical of Mr. Schatz's rebuttal testimony that Pepco's LED streetlight offering were all at 3,000 Kelvin and his characterization of American Medical Association ("AMA") guidelines as supportive of 3000 Kelvin temperature use for safe streetlight operation.[200] The County countered that the AMA recommendations actually encourage 3000 Kelvin or lower for lighting in areas such as roadways.[201]

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[196] *Id.*
[197] *Id.* at 12-13.
[198] *Id.* at 13.
[199] *Id.*
[200] *Id.*
[201] *Id.*

101. The County emphasized that Kensington, as well as several commenters at the public hearing for the instant case, stressed the importance of color temperature and a preference for 2700 Kelvin LED lights.[202] Montgomery County requested that the Commission require Pepco to include the 2700 Kelvin option.[203]

102. The County stated that it supported the smart nodes and the CMS development and integration as a potential improvement of critically important customer service regarding streetlight maintenance and repairs.[204] The County referenced Pepco's response to Montgomery County Data Request 2-1, where Pepco witness Schatz stated that from 2019 through the third quarter of 2020, 83 percent of underground lights were repaired within 15 days and 87 percent of overhead lights were repaired within five days, performing below the guideline of 90 percent repairs and 99 percent of them meeting the 30-day goal, as set forth in Case No. 9217.[205] Montgomery County also noted that Pepco's proposal did not include repair standard changes.[206]

103. Regarding Pepco's proposed use of EmPOWER Maryland funds for the initiative, the County noted that while it had previously used EmPOWER funds to convert the County's streetlights to LED lights, the LED streetlights were customer-owned.[207] The County is further concerned that, should the Commission approve the use of EmPOWER funds, there would be less overall availability of EmPOWER funds for customer-owned energy efficiency efforts.[208]

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[202] *Id.*
[203] *Id.*
[204] *Id.*
[205] *Id.* at 14.
[206] *Id.* at 15.
[207] *Id.*
[208] *Id.*

104. The County recommended that the Commission require Pepco to pass savings from the LED streetlight dimming and on/off scheduling capabilities to customers in order to incentivize the use of these energy-saving features.[209] The County noted that in witness McGowan's testimony, those features typically result in a 60 – 80 percent reduction in energy consumption for a city or utility using smart LED streetlights.[210]

Town of Chevy Chase View

105. The Town of Chevy Chase View ("Chevy Chase View") also referenced LG § 1-1309 in its comments, emphasizing that the statute requires an electric company to sell existing streetlights in a municipality to that municipality upon written request.[211] The Town asserted that Pepco's Application did not present electric delivery rates and related charges for a municipality that purchases street lighting equipment from the utility; therefore, Pepco's application should be denied "until just and reasonable rates and procedures are clearly detailed for a municipality that acquires street lighting equipment from Pepco," without the inclusion of unrelated fees.[212]

Other Party Positions

106. Chevy Chase Village ("Village"), the Town of Chevy Chase ("Town"), and Section 3 of the Village of Chevy Chase ("Section 3") filed an amicus brief in response to the proposed Streetlight Initiative and the pilot program.

107. According to the Chevy Chase municipalities, the Village has approximately 239 high-pressure sodium streetlights, in addition to 26 Village-owned lights.[213] The Chevy

[209] *Id.*
[210] *Id.* at 16.
[211] Town of Chevy Chase View Comments at 1-2.
[212] *Id.* at 2.
[213] Amicus Brief at 3.

Chase Municipalities stated that the Town has approximately 330 high-pressure sodium streetlights and six Town-owned LED sidewalk lights, and Section 3 has 50 high-pressure sodium light fixtures and one induction light fixture.[214] The municipalities stated further that Section 3 has hired a lighting designer and requires a revised 66-fixture lighting pattern.[215]

108. The Chevy Chase municipalities expressed concerns with the initiative, stating that Pepco's proposed 26 LED lighting options are fewer than they appear and are insufficient to provide optimal choices for a residential neighborhood.[216] They noted that both lamp styles and wattages comprise the 26 options, but there are only nine choices of lights to cover a variety of sites, such as major highways and narrow residential streets.[217] Additionally, the Chevy Chase municipalities deemed the lack of customer choice—evident in Pepco's position that it could not, in fairness and economical consideration, permit municipalities to pay for a light upgrade—a major failure of the rate application.[218]

109. The Chevy Chase municipalities asserted that, as noted during this case, the light quality of LED lighting differs from high-pressure sodium and mercury vapor lights; while the lamp wattage can potentially be decreased with a conversion to LED lights, the resulting light color and temperature "may be less attractive to residents and other users due to the whiteness of the light."[219]

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[214] *Id.*
[215] *Id.*
[216] *Id.* at 4.
[217] *Id.*
[218] *Id.*
[219] *Id.*

110. They further echoed the concerns of other localities with the proposed use of 3000 Kelvin LED lights, a level at the top of the AMA recommended Kelvin usage,[220] and noted that the Village preferred to use 2700 Kelvin LED lights.[221]

111. Among their other concerns is shielding. The Chevy Chase municipalities noted Pepco witness Schatz's testimony that shielding, as recommended by AMA guidelines, would be available as an option that can be requested, but the cost is not included in the proposal and would be paid for in a future rate case adjustment.[222]

112. The Chevy Chase Municipalities further noted that the streetlight placement presented another concern, and highlighted Mr. Watson's direct testimony that replacing light for light would likely preserve existing layout errors, as well as Mr. Schatz's testimony that a field inventory would comprise only of an inspection of existing hardware and what must be removed and replaced.[223] The municipalities stated that customers could not meaningfully exercise their right to purchase from Pepco the fixtures it is offering, since the lights are not available to review in their natural environment, and recommended that such ability to review be required as a condition of the Commission's approval.[224]

113. They also recommended that if the Commission approves the tariff, it should make clear that customer purchasers of the LED fixtures will pay only the charges on schedule SL (for energy delivery) and pay for their own equipment and maintenance.[225]

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[220] *Id.* at 5.
[221] *Id.*
[222] *Id.* at 5-6.
[223] *Id.* at 6.
[224] *Id.*
[225] *Id.* at 7.

114. The Chevy Chase municipalities offered the following additional recommendations: (1) that Pepco allow for aggregated RFP bidding by qualified and utility-approved third-party installation contractors and for third-party provision of the lighting that the municipalities would prefer; (2) that the Commission not approve in the tariff any Pepco procedures that would interfere with a municipality's own ability to purchase or maintain its lights; (3) that an approved tariff should make clear that customer-owned, overhead powered lights include the lamp, bracket, and conductor wiring, as confirmed by Pepco during testimony; (4) that the Commission should not approve the Smart Sensor Pilot because it does not involve distribution functions and should not be funded by ratepayers; and (5) that the Commission should only approve the smart node capability as part of the tariff on the condition that the customer will receive the benefit of its results.[226]

GSA

115. The GSA did not file testimony on the MRP but recommended in its post-hearing brief that the Commission reject the Smart LED Streetlight Initiative and direct the Company to work with Staff and the affected parties to this proceeding to develop a comprehensive and cost-effective plan to upgrade Company-owned streetlights in the service territory.[227] While GSA generally supports the conversion to LED lighting, GSA contends that the Initiative, as proposed, is neither well planned nor ready for implementation at this time.[228] Specifically, GSA argues that Pepco has not sufficiently addressed the needs and concerns raised by several Parties in this proceeding who oppose

[226] *Id.* at 7-10.
[227] GSA Brief at 18.
[228] *Id.* at 17.

a one-sizes-fits-all LED conversion approach. As designed, the Initiative "will negatively impact the localities and towns the program is intended to serve."[229] GSA believes the issues raised in this proceeding warrant, at minimum, additional consultation with affected customers in order to bring "meaningful benefits to those customers and realize the program's projected energy efficiency savings."[230]

116. Additionally, GSA agrees with Staff that EmPOWER Maryland funds should not be used to offset any customer rate increase resulting from the streetlight conversion. Rather, GSA believes "[a]ny incremental costs of the Streetlighting program should be borne by the Streetlighting customers themselves rather than being spread among all customer classes."[231] GSA agrees with Staff that using EmPOWER funds to offset the compulsory conversion of streetlights is not an incentive to the customer "since the customer does not have a choice [whether or not to convert the streetlight]."[232] Thus, the Initiative effectively makes Pepco the recipient of the EmPOWER funds, rather than the streetlight customer, and consequently all non-residential customers would pay for the Initiative.[233]

OPC

117. OPC acknowledges that while conversion of streetlights to LED luminaires is worthwhile, Pepco's Initiative is flawed and should not be approved as proposed.[234] At the outset, OPC strongly disagrees with Pepco's proposal to use EmPOWER funds for the Smart LED Streetlight Initiative. OPC states that EmPOWER requires Maryland

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[229] *Id.* at 18.
[230] *Id.* at 19.
[231] *Id.* at 20.
[232] *Id.* at 21.
[233] *Id.* at 21.
[234] OPC Initial Brief at 61.

utilities to implement programs that "encourage and promote the efficient use and conservation of energy by consumers."[235] However, under the Initiative (as proposed), customer participation in the Initiative is mandatory; there is no opt-out provision. Therefore, by definition, "EmPOWER funds would not be encouraging customers to convert to LED streetlights."[236]

118. OPC argues that the Initiative should include greater customer choice.[237] Based on the concerns expressed by several municipalities in this proceeding, OPC observes the overarching concern is removal of customer control over the type of replacement LED luminaires and how to pay for it.[238] In spite of the proposed EmPOWER offset mechanism, OPC argues that Pepco's claim of widespread community support for the program lacks evidentiary support.[239] OPC proposes specific modifications if the Commission ultimately approves the Initiative, including "[enabling] customers with unique needs to procure lighting fixtures outside of the options in Pepco's main offerings (at additional cost if necessary) ...."[240] Alternatively, OPC supports the GSA's recommendation that Pepco's Initiative be denied entirely and that the Company be instructed to develop it further outside of an MRP.[241]

119. OPC recommends that the Commission also deny Pepco's Smart Sensor Pilot Program.[242] OPC contends that the proposed third-party smart sensors fail to fulfill any function of the electric utility, "and therefore they are beyond the scope of Pepco's

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[235] *Id.* at 62.
[236] *Id.*
[237] *Id.* at 63.
[238] *Id.*
[239] OPC Reply Brief at 25.
[240] *Id.*
[241] OPC Reply Brief at 26.
[242] OPC Initial Brief at 64.

authorized powers."[243] OPC further states, "If unregulated third parties are able to provide the same service, then it is not a utility service."[244] OPC notes that the Smart Sensor Pilot is also beyond the scope of the Commission's jurisdictional oversight inasmuch as it is not a utility business function.[245]

Commission Decision

120. Pepco's Smart LED Streetlight conversion proposal first appeared before the Commission in the Company's EmPOWER Maryland program filing for the 2021-2023 Program Cycle in Case No. 9648, as an add-on to the Company's Energy Efficient Communities Programs ("EECP") incentives budget request.[246] In that filing, the Company provided a high level overview of the streetlight conversion proposal (referred to there as the "SLED" project), requested approval to reserve a portion of the Company's greater EECP incentives budget to fund the SLED project—subject to approval by the Commission—and informed the Commission that the project "will be included as part of the Company's rate case being filed in Q4 2020."[247] The Commission addressed the SLED request in Order No. 89679, recognizing that the project "aim[ed] to convert utility-owned streetlights to LEDs in order to reduce energy consumption."[248] The Commission nevertheless denied the request to reserve funding for SLED, reasoning as follows:

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243 *Id.* at 65.
244 *Id.*
245 *Id*.
246 *See generally* Maillog No. 232107: Potomac Electric Power Company's 2021-2023 EmPOWER Maryland Program Filing, 57-60 ("Pepco 2021-23 Plan") (October 9, 2020).
247 Pepco 2021-23 Plan at 57.
248 Order No. 89679 at 38.

> The Commission approves the EECPs without the inclusion of SLED, finding that more information is required prior to making SLED determinations, and that any future rate case filed by Delmarva or Pepco would be the more appropriate location for such determinations to be made.

121. Pepco filed in this case written testimony, oral testimony, a benefit-cost summary, and post-hearing briefs on this issue. Further, other Parties responded in kind to Pepco's proffered evidence. There is no question the Commission has more information about the Smart LED Streetlight Initiative (aka SLED) as a result of this proceeding. While the Commission agrees that conversion to LED streetlights—customer-owned and company-owned alike—should be encouraged, we are not persuaded that the Initiative, as a mandatory program, is consistent with the spirit of EmPOWER Maryland in order to justify using EmPOWER funds to offset rate increases for certain customers.

122. Pepco's rationale supporting the Initiative aligns with State policy in a broad sense—namely, that conversion of company-owned streetlights to LED streetlights will increase energy efficiency and contribute to the State's policy goals of decreasing greenhouse gas emissions. However, the program, as designed, is compulsory for all customers of company-owned streetlights. Despite Pepco's well-intentioned efforts to effect cost parity between current non-LED monthly charges and proposed LED monthly charges, rates will increase for some streetlight customers. To offset any rate increases for these customers, Pepco proposes to use EmPOWER Maryland funds. The fact that these customers cannot opt-out of the streetlight conversion to avoid the rate increase, which could be up to 117% for some customers, goes against the stated purpose of EmPOWER Maryland funds, which should be used to incentivize customers to take action and engage in energy efficiency improvements when they otherwise would not

have done so. The voluntary aspect of EmPOWER is key because the cost of an approved EmPOWER program is shared by all customers within the class.

123. As this proceeding has demonstrated, not all affected municipal customers are friendly towards this Initiative.[249] In fact, several municipal participants that have submitted either evidence or comment on the subject take issue with one or more elements of the Initiative as designed. The Commission finds there are shared themes among the opponents of the Initiative. First, the Initiative lacks customer approval or sufficient customer choice. For example, the Initiative, as submitted, is not flexible enough to accommodate customer options with regard to LED streetlight style, color, temperature, and wattage. Second, the Initiative falls short in customer engagement. Third, the direct benefit of the smart nodes to customers remains unclear. For example, questions raised by Kensington concerning the value of the smart node to the Town, how cost savings from the nodes will be passed on to ratepayers, and whether benefits of the nodes outweigh their associated costs raise valid topics for discussion.

124. Given the concerns raised by the Parties, the Commission cannot approve the Smart LED Streetlight Initiative as part of this MRP. Pepco's costs for the Initiative are not insignificant, and the "zero cost to customer" impact is necessarily tied to securing EmPOWER Maryland funding for those customers who will experience cost increases. As discussed, the proposal, as filed, runs counter to the spirit and intent of the EmPOWER program. This is not to say, however, that the general idea of the Initiative to convert company-owned streetlights to LEDs could not be submitted as a standalone

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[249] While Pepco contends that a number of localities have expressed excitement and enthusiasm about the value of the Initiative to their residents and businesses, it is unclear the extent to which this level of support is tied to the promise of using EmPOWER Maryland funds to ensure cost neutrality.

EmPOWER Maryland proposal. Should Pepco choose to do so, the Company should take the following into consideration: (1) make the program voluntary to incentivize customer action; (2) apply the incentive in a way that helps remove barriers to participation (*e.g.*, rebates that reduce CIAC payments or price differentials in lamp styles); (3) proactively engage interested customers as part of program design; and (4) include smart nodes as an optional technology.

125. For the above reasons, the Commission rejects the Smart LED Streetlight Initiative, as submitted here as a component of the MRP, without prejudice to Pepco to modify and refile as an EmPOWER Maryland proposal for the Commission's consideration in Case No. 9648.[250]

126. Since the Commission does not approve Pepco's Smart LED Streetlight Initiative and pilot program in this case, the proposed tariff changes associated with the initiative, recommended by Staff, also are not approved. Tariff changes will be addressed if and when Pepco brings these proposals to an EmPOWER Maryland proceeding. The municipalities have provided numerous concerns and recommendations regarding Pepco's proposed revised tariff, and the Commission therefore directs Pepco to continue discussions with the municipalities regarding customer choice, purchase of the LED streetlights, and tariff changes if it pursues an EmPOWER filing.

127. Regarding the Smart Sensor Pilot, the Commission finds that Pepco has not demonstrated a sufficient nexus between the stated purpose of the Pilot and the Company's own electric distribution operations to justify approval in this case.

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[250] The Company can also elect to proceed with the initiative as a traditional infrastructure replacement or improvement program at its own expense and seek cost recovery in a future rate case if it believes it can justify the cost.

Throughout this proceeding, several parties raised credible concerns regarding the Pilot, including its cost, the specific benefits to customers, its relevance to Pepco's distribution function, and the lack of sufficient details to assess its cost-effectiveness. Indeed, none of the other parties openly support the Smart Sensor Pilot. Even Prince George's, which does not oppose the Pilot, questions the program's cost and recommends conditions if the Commission decides to approve the program. Although Pepco points us to several community-related functions and potential customer benefits that may be captured through smart sensor technology, such as gunshot detection, air quality and traffic monitoring, we find the connection between these "features" and the Company's core operations tenuous at best. We agree with Staff, OPC, and Kensington that costs of this Pilot should not be recovered through rate base. Accordingly, the Commission denies the Smart Sensor Pilot Program for the MRP.

3. <u>RMA 33 – Reflection of Revenue Requirement Offsets in Rate Base</u>

Pepco

128. Pepco witness Wolverton explained that the Company's MRP included three years of projected revenues and costs to develop three 12-month rate-effective periods, ending March 31, 2022 (Year 1), March 31, 2023 (Year 2), and March 31, 2024 (Year 3), respectively.[251] He noted the application includes a "bridge" year, which is the 12-month period ending on March 31, 2021 between the historical test year of March 31, 2020 through the MRP period beginning April 1, 2021, and represents the period that the case will be under consideration by the Commission.[252] Pursuant to Pepco's proposal, the

[251] Wolverton Direct at 3.
[252] *Id.* at 4.

rates would become effective on April 1st of each year of the MRP.[253] However, the witness testified that due to the ongoing COVID-19 pandemic, the Company proposed to offset the first two years of the MRP entirely, and partially offset the third year's revenue requirement. Pepco witness Wolverton proposed to suspend collection of regulatory assets during the life of the MRP, to accelerate the amortization of non-protected federal excess Deferred Income Tax Liabilities, and to accelerate the amortization of the Additional Subtraction Modification Liability.[254]

129. First, Pepco proposed to pause amortization of its Maryland regulatory assets starting May 24, 2021 and resume amortization on April 1, 2024, thereby extending the recovery period by almost three years.[255] Second, Mr. Wolverton proposed the acceleration of the non-protected property related to the Tax Cuts and Jobs Act ("TCJA") Excess Deferred Income Taxes ("EDIT") liability beginning on May 24, 2021 through March 31, 2024, which would reduce the amortized return from the Commission-approved seven-year (non-protected non-property) and 20-year (non-protected property) periods.[256] Additionally, Pepco proposed to accelerate the amortization of the Addition Subtraction Modification Regulatory Liability from the current 37.93-year period approved in Case No. 9602 (remaining book lives of Maryland assets).[257]

AOBA

130. AOBA witness Timothy Oliver did not support this adjustment, stating that deferring revenue beyond the three-year MRP period "creates an effective balloon

[253] Based on Order No. 89687, the Company's rates were suspended 180 days from December 30, 2020; therefore, the Year 1 rates will go into effect in late June 2021.
[254] Wolverton Direct at 4.
[255] Wolverton Direct at 50-51; *see also* McGowan Direct at 23.
[256] Wolverton Direct at 51.
[257] *Id.* at 51 (footnote omitted).

payment for ratepayers, will produce rate shock, and far outweighs any value to ratepayers ... ."[258]

OPC

131. OPC witness Effron eliminated Pepco's offsets in Year 1 to be consistent with his revenue calculations for MRP Year 1 and eliminated the offsets for Years 2 and 3 in accordance with the Commission's ruling in Case No. 9645.[259] He stated for the first year of the MRP, he "calculated the Company's revenue deficiency exclusive of the effects of the offsets and then calculated the offsets necessary to bring the net revenue deficiency to zero."[260] In light of the Commission's ruling in Case No. 9645, Mr. Effron eliminated the Company's offset related to the pausing of the amortization of regulatory assets. Next, he also accelerated the amortization of excess deferred taxes to reduce the revenue deficiency to zero in Year 1, but did not include any offsets for Years 2 and 3.

132. Mr. Effron reiterated that the offsets should be made in accordance with his revenue requirement recommendations. OPC stressed that consistent with Case No. 9465, it was not in the best interest of ratepayers to pause regulatory asset amortization expense.[261] The offset for Year 1 could be met by acceleration of the EDIT amortization, and OPC recommended no offsets for Years 2 and 3 to provide the Commission flexibility to reevaluate the need for further offsets.

133. In its reply brief, OPC argued Pepco provided no basis to treat its request any differently than that levied in BGE's MRP.[262]

[258] T. Oliver Direct at 36.
[259] Effron Direct at 12; Ex. DJE-1, Schedule B.
[260] Effron Surrebuttal at 2.
[261] OPC Initial Brief at 6.
[262] OPC Reply Brief at 11.

Staff

134. Staff witness Patterson agreed in part with Pepco's revenue requirement offsets, but he recommended consistency with Order No. 89678, specifically fully offsetting the revenue requirement in MRP Year 1 through a revenue offset rider adjustment.[263] Further, he recommended that any offsets for Year 2 should be determined at a future date. Mr. Patterson also recommended that the offset include acceleration of the Maryland Additional Subtraction Modification ("MASM") regulatory asset first and that the Company should not be allowed to pause the amortizations of regulatory assets. Staff's reversal of the Company's revenue requirement offsets resulted in a net adjustment to rate base of MRP year 1 of $11,859,000, MRP year 2 of $50,302,000, and MRP year 3 of $91,653,000.[264]

135. In his surrebuttal testimony, Mr. Patterson continued to assert that operating income and rate base revenue offset adjustments should be included in the offset rider consistent with Order No. 89678.[265]

136. Staff argued that the Commission should follow the same approach as that reflected in BGE's MRP Case No. 9645, namely that the operating income and rate base revenue offset adjustments should be included in an offset rider, and to use the acceleration of the MSAM regulatory liability first.[266] Staff also recommended deferring action on potential offsets for Years 2 and 3.

137. In Staff's reply brief, it reiterated its proposal to accelerate the MASM regulatory asset first and to include the adjustments in an offset rider consistent with Case No.

[263] Patterson Direct at 21.
[264] *Id.* at 22.
[265] Patterson Surrebuttal at 5.
[266] Staff Initial Brief at 16 (footnote omitted).

9645.[267] This methodology will allow the Commission to fully offset the revenue requirement in Year 1 of the MRP.

Pepco Rebuttal

138. In his rebuttal testimony, Pepco witness Wolverton confirmed that the Company's proposals remained unchanged. The intent of this adjustment was to include the impact of offsets on rate base. He noted that Staff's adjustment completely eliminated RMA 33 as if Staff was proposing no revenue requirement offsets.

139. Mr. Wolverton did not object to Staff witness Patterson's proposal related to the order of which offsets to apply, but cautioned that pausing regulatory asset amortization might be necessary depending on the Commission's decision. In order to achieve full offsets in Years 1 and 2 and a partial offset in Year 3, Mr. Wolverton opines that regulatory asset amortization must be paused to ensure there are sufficient benefits available.[268] He also cautioned that each offset only has a specific amount for each customer class. Mr. Wolverton added, "in the event the Commission determines that some level of revenue requirement offsets are prudent, there needs to be rate base recognition for the impact of those offsets."[269] Mr. Wolverton also updated his adjustment to include actual incremental costs and savings through December 2020.[270]

140. In Pepco's initial brief, the Company explained its proposal to offset the entire proposed revenue requirement for Years 1 and 2 and partially offset Year 3. Pepco recognized the Commission may take other action; therefore, it urged that "if the Commission decides to utilize some amount of offsets to Pepco's approved revenue

[267] Staff Reply Brief at 7-8.
[268] Wolverton Rebuttal at 24.
[269] *Id.* at 25.
[270] *Id.* at 36-37.

requirement, there should be a recognition in rate base of the impact of those offsets."[271] In its reply brief, Pepco stated that it did not object to Staff's proposed prioritization of offsets, but stressed that the offsets must be reflected in rate base.[272]

Commission Decision

141. In light of the continuing severe health and economic impacts from the COVID-19 pandemic, the Commission continues to find it prudent to use tax refunds and other adjustments to prevent an increase in customer bills in Year 1 of this MRP. Just as in Order No. 89678, the Commission will not, as this time, determine the use of offsets into Years 2 and 3.[273] While the State and the country are beginning to recover from the COVID-19 pandemic, the economic effects will likely linger for some time. Therefore, the Commission finds it appropriate to provide Pepco's customers the same relief from impending rate increases as provided in BGE's MRP case. With sufficient EDIT and MASM funds available, the Commission can ensure that customers do not experience a net increase in their bills during the first year of the MRP. We will revisit the potential for offsetting the revenue requirements applicable to Years 2 and 3 at a future date, when more information regarding our post-pandemic recovery is known.

142. The Commission recognizes that altering amortizations of regulatory assets and liabilities may result in future costs to customers who will experience higher bills beginning in the second year of the MRP. However, the Commission remains concerned that extending the proposed offsets in Year 2 could result in less transparency because offsets make the Company's cost of service appear to be less expensive than is actually

[271] Pepco Initial Brief at 45.
[272] *Id.* at 25 (footnote omitted).
[273] *See* Order No. 89678 at 11.

the case. Such an approach could result in large increases at the conclusion of the MRP, possibly constituting rate shock and intergenerational equity concerns in future years. Therefore, consistent with Order No. 89678, the Commission will reconsider the use of offsets for the later years of the MRP. The appropriate Year 2 and 3 rate increases will be dependent upon the Commission's evaluation of the state of the economy, the status of the COVID-19 pandemic recovery, and Pepco's proposed work plans that shall be contained in a 60-day report, as discussed below. Once the Company files its report, all stakeholders will have an opportunity to provide comments on both the work plan and the potential use of offsets.

143. Pepco has failed to provide any reason for the Commission to reconsider its decision regarding offsets issued in the BGE decision just over six months ago. The roadmap for this issue was detailed in Order No. 89678 and could easily have been followed. Therefore, the Commission finds no reason to depart from our ruling in the BGE Pilot MRP on this issue.

144. Consistent with Order No. 89678, the Commission makes the same findings regarding the available pool of offsets. The Commission finds that suspending the collection of regulatory assets is not necessary to fully offset the Year 1 revenue requirement granted in this order. Further, it is appropriate to accelerate the return of the TCJA EDIT and MASM regulatory liabilities, but only to the extent necessary to avoid rate increases for Year 1. The remainder of these liabilities, at least for now, shall be returned to customers pursuant to Pepco's original timetables. This will provide the Commission with flexibility to reconsider the acceleration of offsets in future years of the MRP. Finally, the Commission accepts Staff's proposal that Pepco should exhaust the

MASM liability first before accelerating the return of the non-protected portions of excess deferred income taxes.

4. **Capital Projects**

Pepco

145. Pepco witness Stewart stated that Pepco's reliability has seen major improvements over the last decade and, in 2019, it had the best reliability indices of any utility in the State.[274] Since 2012, the Company's System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") have improved by 48% and 64%, respectively, and the Company is now in the first quartile of reliability service performance.[275] He anticipated that Pepco's reliability performance would continue to improve and that system reliability is an ongoing process.

146. Mr. Stewart asserted that it would be inappropriate for the Company to stop its reliability programs because of its success as the system would degrade and void all improvements due to inaction. The Company's next steps in terms of reliability will be focused on a few major categories, including smaller, neighborhood efforts with programs targeting Customers Experiencing Multiple Interruptions ("CEMI") and multiple device outage improvements; infrastructure renewal programs; and advanced "smart" equipment/monitoring where technology continues to improve.[276] Mr. Stewart testified, "Continued reliability investment is imperative in maintaining consistent service

[274] Stewart Direct at 5.
[275] *Id.* at 5-6.
[276] *Id.* at 8-9.

performance levels and contractions of these investments serve to degrade performance," highlighting the importance of replacing aging infrastructure.[277]

147. Pepco witness Stewart testified that the Company must continue to make capital investments in order to meet both customer expectations and future reliability requirements. He stated that Pepco developed its planning margins based upon three factors: historical storm activity and performance; potential storm impact; and transmission event impact.[278] The Company's Capital Distribution Forecast for 2020-2024 is an investment of approximately $1.350 billion.[279]

148. Pepco witness Stewart described Pepco's processes and procedures in relation to project authorization and development. In the first phase, a project is proposed with the need, objective, and preliminary cost, followed by a project team developing the conceptual design and scope of the project.[280] The project is then designated as capital, information technology-related, or another classification, and the cost estimates are developed with a +/-50% margin.

149. Next is the design phase where the engineering design is reviewed, material procurements are specified, required permits are identified, construction specifications are determined, and estimates are developed within a +/-25% margin.[281] After the project is approved by the oversight committee, it moves into the third phase where the final design, materials and contracts are awarded, construction begins, and the estimates are

[277] *Id.* at 10.
[278] *Id.* at 18, Table 5.
[279] *Id.*
[280] *Id.* at 19.
[281] *Id.*

developed within a +/-10% margin.[282] Pepco witness Stewart noted that the largest capital projects are reviewed by the Project Concurrence Committee, which approves capital projects between $5 and $15 million.

150. Pepco witness Stewart explained Exelon's work management process, which helps screen, plan, and schedule more efficiently. The Company's work is scheduled weeks in advance, which permits Pepco to "create work down curves based on what is scheduled in its system and provide meaningful analytics to track the execution of these programs."[283] He stated that the mission of the Exelon Peer Group is to share best practices and experiences and attributed Pepco's reliability performance as a practice gained from Exelon, specifically Exelon's practice of completing as much identified maintenance and planned reliability work as possible prior to the winter and summer storm seasons.[284] Pepco also adopted Exelon's "Restore then Repair" approach, which restores as many customers as possible through temporary means before focusing on longer-term repairs, which reduces the number of customers experiencing an extended outage.[285] Pepco has also adopted Exelon's approach to managing both planned and corrective work which has added rigor and oversight to the successful execution of capital projects and system maintenance.[286] This process has helped the Company screen, plan, and schedule more effectively. Finally, Pepco witness Stewart claimed that as a result of Exelon's structuring each of its utilities according to a standard template, "leaders at all levels at each of the utilities are able to socialize operational and

[282] *Id.* at 19-20.
[283] *Id.* at 21.
[284] *Id.*
[285] *Id.* at 21-22.
[286] *Id.* at 22.

engineering challenges encountered as well as collaboratively solve problems via Exelon's peer network."[287]

151. Pepco witness Stewart stated that the Company has spent $1.082 billion from 2016 to 2019 in order to improve the system's performance and reliability. As a result of those investments, between December 2015 and December 2019, Pepco's SAIFI and SAIDI have improved by 27% and 37% respectively.[288]

152. Pepco explained that projects deemed "Reliability Investments" include those that, when taken together, will improve performance for customers: System Performance; Capital Corrective Maintenance; and System Performance Automation. First, System Performance "improves performance through modifications to system design and application of new technology and equipment to prevent outages and reduce the number of customers impacted by an outage," and includes Feeder Reliability Improvement, Proactive Replacement of Underground Residential Cables, Switchgear Replacements, and Installation of electronic reclosing fuse technologies.[289]

153. Pepco detailed its Corrective Capital Replacement program as more reactive with replacements originating from field submissions/preventative maintenance review of deficient equipment.[290] Pepco witness Stewart stated, "Work performed within this category directly benefits customers by identifying aging system equipment to be replaced before it fails, thereby preventing future outages from occurring."[291] Also

[287] *Id.* at 22-23.
[288] *Id.* at 25.
[289] *Id.* at 26-27.
[290] *Id.* at 30.
[291] *Id.* at 31.

included in this program was emergency restoration work, which is reactive in nature and benefits customers by alleviating future outages for the same cause.

154. Mr. Stewart outlined Pepco's Distribution Automation program as designed to install new field devices in order to reduce customer interruptions, expedite restorations, and improve the emergency responses and execution of switching for fault isolation by way of Distribution Automation projects.[292] These projects are designed to limit the number of customers impacted by an outage and automatically restore service after an interruption. Projects in this category also include the installation of ASR (Automatic Sectionalization and Restoration) schemes, which work together to identify distribution feeder faults, automatically isolate an identified fault area, and reroute electricity supply to segments of the feeder not impacted by the fault.

155. Pepco witness Stewart described the Company's Smart Grid system and noted benefits of the system, including increased visibility of the energy grid and customers on it, thereby enhancing customer service. It also improves the quality of underlying outage information and estimated restoration times.

156. Pepco witness Stewart explained that these projects are primarily focused on the replacement of infrastructure at or near substations and also include the conversion of feeders to higher operating voltages, thereby enabling the implementation of distribution automation schemes, as well as creating greater hosting capacity for distributed energy resources, such as solar, energy storage, and electric vehicles.

[292] *Id.*

OPC

157. Witnesses Alvarez and Stephens found numerous deficiencies in Pepco's distribution planning and investment decision-making practice, namely the failure to "(1) use qualitative, rather than quantitative, approaches to assess (and prioritize) the distribution risks the Company faces; (2) inadequate identification of alternatives to Company capital; and (3) inadequate evaluation of available alternatives on a 'risk reduction per dollar' basis."[293] They asserted that the Company did not quantify any of the risks Pepco claimed to be addressing with the various capital projects. Without considering measurable risks, Witnesses Alvarez and Stephens stated, "there is no ability to rigorously prioritize risks to be addressed in a distribution plan, nor an ability to compare the cost alternative solutions to their risk reduction value."[294] They claimed Pepco's process uses subjective estimates rather than actual historical data. They also opined that "subjective estimates of reliability risk are prone to over-estimation, and insufficiently rigorous for projects denominated in the tens of millions of dollars."[295] They found that the Company's distribution planning practices were capital biased and that the amount of risk reduced by the proposed projects did not justify their construction. As such, they concluded that $594.78 million be disallowed from Pepco's proposal, which they found to be unnecessary.[296]

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[293] OPC Panel Direct at 11.
[294] *Id.* at 12.
[295] *Id.* at 18.
[296] *Id.* at 43, Table 2.

Staff

158. Mr. Austin's review of the Company's proposed capital expenditures resulted in his recommendation of an overall $100.9 million disallowance for various projects as discussed below.[297]

Pepco

159. In rebuttal, the Company expressed concerns over OPC's and Staff's proposed adjustments to its capital budgets. Pepco witness Anthony was concerned with both OPC and Staff's positions, which would reduce much of Pepco's MRP budget and "would significantly underfund and impair programs crucial to maintaining system reliability, halt projects that address identified reliability risks, and defer investments which are needed to ensure the Company operates a safe and reliable distribution system."[298] He cautioned that acceptance of OPC's and Staff's adjustments would "severely challenge the ability of the Company to meet Commission-ordered reliability standards."[299] Pepco witness Anthony believed Pepco's proposals were reasonable based upon the needs of its system and customer expectations. He testified, "Pepco's planning process is designed to ensure that adequate infrastructure exists to supply safe and reliable electric service for all of its customers and to do so at a reasonable overall cost."[300] Pepco witness Anthony highlighted that the Company's planning process allowed it to meet its merger reliability requirements and achieve first quartile performance by spending approximately $43 million less than Pepco's commitment.

[297] *See* Patterson Direct, Ex. FP-7.
[298] Anthony Rebuttal at 6.
[299] *Id.*
[300] *Id.* at 8.

160. Mr. Anthony stressed that many of the projects and programs in the MRP are not new and have previously been reviewed and found to be prudent in other proceedings. He asserts that Pepco's 69kV program will harden the Company's system and has already identified weaknesses in its sub-transmission system.[301] He indicates that substation projects are necessary to resolve overload conditions, some of which are in highly recognizable growth areas.[302] Mr. Anthony argues that acceptance of OPC's positions would undermine decisions made in Case No. 9353 and put Pepco at risk of financial penalties if reliability standards are not met. Furthermore, if the substation projects are disallowed, he still expected overload conditions to occur.

161. Pepco defended its Capital and O&M Plans, as well as its Distribution Program, which it claimed was designed to maintain a safe and reliable system while meeting customers' expectations. The Company projected to spend $1.09 billion during the MRP on upgrades and improvements, many of which it states are not new to the Commission and have been ongoing for several years as part of the Commission's electric reliability docket (Case No. 9353) and prior rate cases.[303] As a result of the Company's program, Pepco maintains that its system reliability improvements were accomplished in a cost-effective manner. Pepco described its five-year planning process and its "ground up" approach in which "proposed capital projects are each assigned to project managers and executive ownership to ensure appropriate accountability and governance."[304]

162. In response to the initial briefs, Pepco defended its Capital Programs and Budgets. The Company claimed that its MRP budgets were in line with what has been spent over

[301] *Id.* at 12.
[302] *Id.* at 13.
[303] Pepco Initial Brief at 15-16.
[304] *Id.* at 18 (footnote omitted).

the past several years in accordance with the Commission's prudency reviews in prior rate cases. For example, from 2016-2019, Pepco points out that it invested $1.08 billion in capital for Maryland’s distribution system, compared to $1.09 billion over the 2021-2024 time period proposed in this case.[305] Furthermore, the Company noted that it met its merger commitments while remaining $43 million under budget, which, according to the Company, rebuts OPC’s claim that Pepco’s process is capital-biased.

163. Pepco dismissed OPC’s claims that less-expensive, non-capital options were available and stated that OPC failed to indicate what those alternatives were or to offer any analysis of the unknown alternatives’ impact on the distribution system.[306] The Company highlighted that outages have been reduced by 48% and customers were restored 64% faster since 2012, and that 2020 represented the Company’s highest reliability performance to date.[307] Pepco averred that the results stemmed directly from investment and work plans over the past several years. The Company dismissed OPC’s criticism of the planning process and argued that OPC’s “risk reduction per dollar” approach could result in prioritizing investments by customer class or geography in a manner that conflict with Pepco’s obligation to provide reliable service for all customers.[308]

<u>Commission Decision</u>

164. While leaving broader distribution planning issues to a workgroup, the Commission does address parties’ requests regarding specific capital spending initiatives below. Parties often recommend a “disallowance,” but it is important to note that the

[305] Pepco Reply Brief at 7.
[306] *Id.* at 8.
[307] *Id.* at 9.
[308] *Id.* at 11.

Commission is not conducting a prudency review of planned MRP spending at this time. Rather, the Commission is considering projects for inclusion in the MRP revenue requirement, which will allow nearly contemporaneous recovery of capital expenditures. Whether a project should receive this type of accelerated recovery is a separate question from whether a project should or should not be constructed.

165. The Commission's decision herein will provide a capital budget and associated revenue requirement. Pepco will remain responsible for determining how much it needs to spend, and how best to spend, in order to satisfy its obligations to provide safe, affordable, and reliable electric service on planning issues to a workgroup; the Commission does address parties' requests regarding specific capital spending initiatives below.

166. Parties often recommend a "disallowance," but it is important to note that the Commission is not conducting a prudency review of planned MRP spending at this time. Rather, the Commission is considering projects for inclusion in the MRP revenue requirement, which will allow nearly contemporaneous recovery of capital expenditures. Whether a project should receive this type of accelerated recovery is a separate question from whether a project should or should not be constructed.

5. IT and Real Estate

Pepco

167. Pepco witness Barrett described various anticipated benefits of the IT capital projects the Company proposed. Specifically, Mr. Barrett anticipated improvements to the customer experience by providing them with tools to help manage energy use, support for business transformation strategies, maintenance of operational and secure platforms,

and efficiency optimization.[309] He stated that the IT capital projects drive operational improvements, reduce risk, and increase reliability.[310]

168. In relation to the Company's facilities' capital expenditures, Mr. Barnett noted that a list of facility investments was prioritized over the next five years and was targeted to support ongoing operations, keep facilities current with modern amenities and standards, and promote a healthy and safe environment for employees and customers.[311] According to Mr. Barnett, the actual expenditures for 2019 and 2020 were $10,096,000 and $30,929,000 respectively, while the forecasted expenditures were as follows: 2021 – $24,864,000; 2022 – $7,206,000; 2023 – $7,309,000; and 2024 – $10,794,000.[312]

Staff

169. Staff witness Patterson recommended an adjustment to the Company's capital projects in accordance with BGE'S MRP (Case No. 9645) for certain IT projects, other than those that relate to managing and operating the electric system, and Real Estate and Facilities capital projects.[313] Mr. Patterson testified that Staff made adjustments to projects that were estimated to extend over five years to reduce the impact on customers by reducing the speed of spending in accordance with Order No. 89678.[314] He reviewed Pepco's IT and Real Estate projects, both actual and forecasted amounts, from 2016 through 2024. In terms of historical figures, the forecasted and actual amounts for IT projects between 2016 and 2019 were as follows:[315]

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[309] Barnett Direct at 39.
[310] *Id.* at 40-41.
[311] *Id.* at 41.
[312] *Id.* at 42, Table 7.
[313] Patterson Direct at 14.
[314] *Id., citing* Order No. 89678 at 101-102, para. 211-213.
[315] Patterson Direct at 10 and Ex. FP-5.

Table 3 Forecasted and Actual IT and Real Estate Amounts (2016 – 2019)			
Year	**Forecasted**	**Actual**	**Difference $/%**
2016	$15,997,000	$11,243,000	($4,754,000)/-30%
2017	$16,424,000	$21,941,000	$5,517,000/24.2%
2018	$59,799,000	$65,135,000	$5,336,000/9.2%
2019	$31,876,000	$43,742,000	$11,866,000/28.1%

170. In relation to Real Estate and Facilities Projects over the same time period, Staff witness Patterson found the following:[316]

Table 4 Staff Amounts for Real Estate and Facilities Projects (2016 – 2019)			
Year	**Forecasted**	**Actual**	**Difference $/%**
2016	$10,241,000	$9,733,000	($508,000)/-4.96%
2017	$2,023,000	$1,302,000	($712,000)/-35.6%
2018	$9,070,000	$1,858,000	($7,212,000)/-79.5%
2019	$6,001,000	$10,096,000	$4,095,000/40.6%

171. In his surrebuttal testimony, Staff witness Patterson defended Staff's adjustment extending the project costs from three years to five years for consistency with Order No. 89678, noting that the projects were not critical to reliability and extending the projects would not impact the Company's operations.[317] However, he amended his adjustment to reflect Pepco witness Wolverton's allocated plant in service adjustment, as well as

[316] *Id.*
[317] Patterson Surrebuttal at 2, *citing* Order No. 89678 at 100-102, para. 210-213.

adjustments to accumulated depreciation and accumulated deferred income taxes and depreciation expense.[318]

172. Staff asserted that its proposed adjustment was consistent with BGE's MRP in Case No. 9645 despite Pepco's contention the projects were unique.

Pepco Rebuttal

173. Pepco witness Barnett argued that Pepco's proposals were consistent with recent spending levels and were supported by the record, whereas the BGE adjustments relied upon by Staff were outliers and unsupported.[319] He emphasized that both the IT and Real Estate projects were "vital to Pepco's delivery of reliable electric service and for ensuring a safe work environment for the Company's employees."[320] Mr. Barnett testified that the IT projects enhance cybersecurity and Pepco's ability to maintain operations, and the Real Estate projects will provide physical security to equipment and personnel and mitigate environmental risks.

174. Pepco witness Barnett explained that the IT projects benefit ratepayers by ensuring an effective communications network and capabilities for storm outage responses; enhancing customers' experience during critical events; improving billing and self-service options; improving sign-up and move-in/move-out experience; creating new functionality to better support deferred payment arrangements and use of limited income assistance programs; and supporting timely life-cycle replacement investments.[321] He stated that the Communication Tower Infrastructure was necessary to meet requirements of the Federal Communications Commission, and the Firewall Refresh was part of the

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[318] Patterson Surrebuttal at 2-3 and Ex. FP-14S, *citing* Wolverton Rebuttal - Schedule TWW-R-2.
[319] Barnett Rebuttal at 3-4.
[320] *Id.* at 4.
[321] *Id.* at 6.

data network security system, which will protect against unauthorized access, data theft, and installation of malicious code, and maintain cybersecurity overall. Mr. Barnett also noted that the existing firewall is at the end of its useful life.[322] He continued that the Utility of the Future Digital Program will improve the performance of digital channels and customers' experiences and ability to interact with the Company.[323]

175. Pepco witness Barnett described the various elements of the $39.5 million Emerging Project Pool. He explained that these budgeted costs represent funding for a collection of projects that require further analysis and design prior to final prioritization.[324] The projects include an end-of-life upgrade for key operational systems, customer energy efficiency tools, DER connection support, streamlined call interaction, improved analytics and reporting for operating storm preparedness and response reducing outage times, and customer communications for outages and field work.[325]

176. In relation to the Security Systems and Equipment investments, Pepco witness Barnett stated the replacements and upgrades were both prudent and beneficial to customers. He asserted the projects were necessary to improve the Company's facilities, improve employee productivity and safety, and maintain customer service satisfaction levels.[326] He added that the Forestville Fuel Island was necessary to remove underground fuel tanks that are at the end of their useful life, in order to avoid environmental risks associated with delayed replacement. Mr. Barnett explained that the Benning Campus

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[322] *Id.* at 7.
[323] *Id.* at 9.
[324] *Id.*
[325] *Id.* at 10.
[326] *Id.* at 12.

Renovation was required to modernize aging facilities, address an inadequate traffic pattern, and improve the interiors and amenities.[327]

177. In its initial brief, Pepco distinguished this issue from Order No. 89678 in BGE's MRP case wherein the Commission adjusted BGE's plans based on outliers OPC identified as significantly more expensive relative to historic spend or as unsupported by the record.[328] In this case, Pepco argued that its plans were supported by the record and that Staff did not raise that issue or contend that the plans were unreasonable.

178. Pepco argued that Staff's failure to challenge either the need or prudency of these projects should lead the Commission to reject Staff's recommendation. Pepco indicates that since these investments were not "outliers, unnecessary, or imprudent, these budgets are by definition reasonable indicators of projected investments and necessary revenues during the MRP period."[329]

<u>Commission Decision</u>

179. In Order No. 89678, the Commission determined that extending spending on certain accounts benefited ratepayers by reducing the speed of spending and allowing BGE to prioritize its work plans; however, the Commission specified that it only approved three years of budgeted spending.[330] We find no reason to alter that approach in this proceeding. While no party challenged the appropriateness of Pepco's work plans, the Commission nonetheless deems it appropriate to reduce the financial impact on ratepayers at this time. As noted by Staff, there were several years when the Company's actual costs varied significantly, both higher and lower, from what had been forecasted.

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[327] *Id.* at 13-14.
[328] Pepco Initial Brief at 39, *citing* Order No. 89678 at 101.
[329] Pepco Reply Brief at 21.
[330] Order No. 89678 at 101-102, para. 211-213.

Given that past performance is the best indicator of future performance, the Commission is concerned about the accuracy of the Company's 2021-2023 forecasts based upon the budgeted versus actual figures from 2016 to 2019.

180. This decision does not preclude or prejudge the Company's recovery of these costs, but given the relative infancy of MRPs in Maryland and Pepco's accuracy, or lack thereof, on these issues, the Commission's finds a more cautious approach is warranted. Accordingly, Pepco is directed to extend the spending time frame for its Real Estate and IT work plan budgets from three years to five years.[331]

181. Consistent with Order No. 89678, the Commission is approving only three years of budget spending and is not approving further work in these areas. Pepco is directed to make a filing within 60 days of this Order that either: (i) accepts the reduced revenue requirement as presented herein; or (ii) proposes to prioritize the reduced revenue requirement on a different set of work plans in order to maximize the benefit of the overall capital work plans.[332]

6. <u>Corrective Maintenance Program</u>

<u>Staff</u>

182. Staff witness Austin expressed concern with Pepco's combined Corrective Maintenance budget as it was approximately 23.5% greater ($101.9 million increase from 2021 to 2023) than what was presented in Case No. 9353.[333] Based on those increases, Mr. Austin recommended disallowances of $0.9 million in 2021, $10.1 million in 2022, and $8.4 million in 2023, which represented the differences between the Company's

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[331] *See* Order No. 89678 at 102, para. 212.
[332] *Id.* at 102, para. 213-214.
[333] Austin Direct at 15-16, *citing* Maillog No. 220588.

proposed budget in Case No. 9353 and its recommended spending in this proceeding.[334] In surrebuttal testimony, Mr. Austin claimed the Company failed to address a 23.5% difference in the Corrective Maintenance program in this case compared to levels presented in Case No. 9353.[335] Therefore, he maintained that a $19.4 million disallowance was appropriate.

183. In its brief, Staff noted the Company's varying Corrective Maintenance budgets for 2021-2023 of $92.613 million versus the projected $82.5 million that was forecasted in 2017/2018, and the $74,060,559 that was forecasted as part of Pepco's 2020 Annual Performance Report in Case No. 9353.[336] Staff argued that while there may be a reasonable explanation for the variance, they expressed concern over the transparency of the Company's budgets.[337]

184. Staff expressed concerns about the Company's forecasted 28 percent increase in the Corrective Maintenance budget for the 2021-2023 time period, compared to 2018 estimates.[338] Staff pointed to differences in the Company's MRP estimates and costs in Pepco's 2020 Annual Report filed in Case No. 9353, and continued to support a $19.4 million disallowance.

Pepco Rebuttal

185. Pepco witness Stewart countered that the Corrective Maintenance – Distribution Lines Portfolio included projects "that are both emergent in nature and those that are identified from age and deterioration inspections as part of our preventative maintenance

[334] Austin Direct at 16.
[335] Austin Surrebuttal at 13.
[336] Staff Initial Brief at 11-12, *citing* Pepco's 2021-2023 SAIDI/SAIFI Standards update (Maillog No. 220588) at 14 and Pepco's 2019 Annual Performance Report pursuant to COMAR 20.50.12.02E.
[337] Staff Initial Brief at 12-13.
[338] Hr'g Tr. 1085-86; Staff Reply Brief at 4 (footnote omitted).

programs."[339] According to Mr. Stewart, approximately 80% of the portfolio addressed outage response and non-blue sky day events, with the remaining budget addressing priority-type abnormalities that pose operating risks to the system.

186. In its brief, Pepco argued that this work reflected "the costs of emergent and non-emergent 'non-discretionary' maintenance work that must be performed on its distribution and substation system in order to maintain system reliability."[340] The Company noted that this included the replacement of various capital infrastructure that was both tracked and monitored so the forward-looking distribution plans could be executed. The Company characterized the rationale for Staff's adjustment as solely the fact that today's estimates are higher than 2018 estimates and argued that the Commission should not accept Staff witness Austin's recommendation without supporting data or analysis. Pepco concluded that the work was non-discretionary and must be performed.[341]

187. In its reply brief, Pepco noted that Staff did not claim the work was either discretionary or could be delayed, but Staff's disallowance was mistakenly based upon a discrepancy in the budgets in Case No. 9353 compared to the forecasted budgets in this proceeding for the same work.[342] The Company stressed that the increases in the MRP budget were due to "the actual work that Pepco has performed over the past few years for 'gray sky storm restoration.'"[343] Pepco indicates that the budgets for this item are more

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[339] Stewart Rebuttal at 33.
[340] Pepco Initial Brief at 32, *citing* Stewart Rebuttal at 33.
[341] Pepco Initial Brief at 33, *citing* Hr'g Tr. 294-295 (Stewart).
[342] Pepco Reply Brief at 18.
[343] *Id.*

accurate than the 2018 estimates because of the level of non-discretionary work the Company is experiencing.

Commission Decision

188. The Commission agrees with the Company's position and rejects Staff's adjustment. While the estimates have increased over time, as noted by the Company, the Commission finds this work to be non-discretionary. However, the Commission shares Staff's concern over the varying figures and notes Pepco witness Stewart's statement that a potential reason for the difference between the forecasts could have been non-reportable reliability work.[344] The Commission directs Pepco to include in future estimates for corrective maintenance all work, broken down by reportable and non-reportable work, which will increase the transparency of the budgets and provide both the Commission and stakeholders a better understanding of the Company's true all-in costs.

7. 69kV Feeder Rebuild Program (including 13kV Underbuild)

OPC

189. OPC witnesses Alvarez and Stephens explained that these 69 kV and 13kV feeder lines link substations together and establish a web of at least two electric supply sources to each substation so that if one line fails, the second line has sufficient capacity to support the substation at peak demand.[345] The Company is seeking to replace 13 of its 69kV lines at a cost of $595.7 million. OPC recommended the program's removal from the MRP, asserting that the enormous costs to customers were not worth the small reliability risk reduction, calculated based on the Company's historical outage data.

[344] Staff Initial Brief at 12, *citing* Hr'g Tr. 323-325 (Stewart).
[345] OPC Panel Direct at 24.

Witnesses Alvarez and Stephens testified that outages would continue due to weather, vegetation, and equipment failure and that no project resolved a reliability concern that was deemed to be urgent. OPC dismissed the Company's justification—the 2010-2012 exceptional storm years—as a basis for the projects, as none of Pepco's Reliability Action Plans since that time described a complete 69kV rebuild.[346] OPC claimed the Company's 69kV line hardening, at a cost of $10 million per year, was both prudent and effective, but found spending another $595.7 million for minimal reliability improvements unnecessary.[347]

190. Witnesses Alvarez and Stephens maintained their position in surrebuttal, that the Company's proposed spending plan is insufficient evidence that the reliability benefits outweigh the $653.6 million costs. They state that since 2016, the concerns of customers have been addressed, and there have been no substation outages. Further, they found Pepco's risk-scoring methodology to be subjective because the Company engineers failed to quantify the risk reduction benefits and alternatives relative to costs. They stated, "The probability assessment is not based on an actual review of historical equipment failure rates, nor the rates at which such failures cause outages."[348] They noted that the Company does not develop risk scores for each alternative to allow comparison. They also dismissed the 2014 study conducted by Pepco's consultant, Enercon, as it failed to mention alternatives to maintaining the 69kV line hardening program.

191. In its brief, OPC continued to recommend disallowance of the $653.6 million 69kV line rebuild program. OPC pointed out that the Company's Major Event Days

[346] *Id.* at 28.
[347] *Id.* at 29-30.
[348] OPC Panel Surrebuttal at 10, *citing* OPC Panel Direct at 17.

between 2010 and 2020 indicate a decrease in severe storms, but not as much of a decrease in substation outages during the same time period.[349] OPC opined that the hardening of the 69kV lines, a significantly cheaper alternative than a rebuild, would also improve reliability. OPC claimed Pepco failed to justify the program's significant cost with a corresponding risk reduction and that, even if all of the 69kV lines are rebuilt, there will still be outages caused by weather, vegetation, and equipment failures.[350] OPC recommended consideration of the 69kV Rebuild Program be included in a distribution planning process outside of a rate case.

192. In its reply brief, OPC argued Pepco's statements amounted to scare tactics and hyperbole, and that the proposed disallowances' impact on the Company's financial health was not relevant as the capital investments are made to benefit rate payers, not the Company.[351] Moreover, OPC did not assert that reliability improvements should not be made, but that less expensive alternatives should be considered and used where appropriate. OPC indicates that Pepco failed to justify the incremental costs of the 69kV rebuild over other hardening options, and only considered the most capital-intensive and expansive options.[352]

Staff

193. Staff witness Austin explained the Company's intent to rebuild twelve 69kV feeders between 2019 and 2029. In Case No. 9602, Pepco's last base rate case, the estimate of the rebuild program after completing the remaining 12 feeders was $428.8 million; however, the revised estimate of $653.6 million through 2030 represents a 52%

[349] OPC Initial Brief at 13, *citing* Alvarez and Stephens Direct at 29.
[350] OPC Initial Brief at 13-14, *citing* Alvarez and Stephens Direct at 26.
[351] OPC Reply Brief at 3.
[352] *Id.* at 6.

increase.[353] Staff witness Austin noted that in Case No. 9602, he recommended disallowance for all funds spent under this program due to its minimal impact on reliability, the lack of an avoided outage cost-benefit analysis, and that the program did not prevent customer outages during storm events in the previous five years.[354] For the same reasons, he recommended Pepco not be permitted to recover in the MRP any funds spent on this program, which includes several 13kV Underbuild projects.[355]

194. In his surrebuttal testimony, Staff witness Austin reiterated the program's minimal impact on normal "blue sky" reliability, the lack of an avoided outage cost benefit analysis, and the lack of any avoided customer outages during the past five years. These concerns of Staff, first raised in Case No. 9602, all remain in this case, and are compounded by a 52% increase in estimated costs to approximately $627.8 million.[356] He dismissed Pepco's reliance on the Enercon report because it failed to assess cheaper alternatives or even evaluate cheaper less-hardened solutions that could still provide reliability and resilience.[357] Mr. Austin agreed that there may be a need to replace some of the 69kV infrastructure but testified, "this project is exorbitantly expensive providing little blue sky reliability and disputable resiliency benefits that the Company has not been able to quantify."[358] He recommended that the project be immediately stopped to consider alternatives.

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[353] Austin Direct – Revised at 25, *citing* Maillog No. 220588, Figure 9 and Pepco's Response to Staff Data Request 35-25.
[354] Austin Direct – Revised at 25, *citing* Case No. 9602 - Austin Direct at 14-19.
[355] Austin Direct at 25-28, Table 15.
[356] Austin Surrebuttal at 13.
[357] *Id.* at 15-16.
[358] *Id.* at 16.

195. In its brief, Staff argued that the $224.8 million increase to the program's estimated cost since 2019 yields a $1,130 per customer cost.[359] While the cost of the program has significantly increased, the associated benefits have not, according to Staff. Staff highlighted Pepco's intent to spend approximately $1.09 billion on upgrades and improvements to its Maryland's distribution system during the 2021-2024 time period and that from 2012 through 2022, the Company's rate base was anticipated to have grown by approximately $760 million.[360] Staff claimed this was evidence of Pepco's ballooning capital spending and the significant cost increase for this program justified removing spending germane to this program.

196. In response to Pepco, Staff continued to argue there has been no analysis to support the claimed reliability benefits or justify the significantly increased costs. The arguments that Staff previously raised in Case No. 9602 are the same as in this proceeding, but have more validity now as the costs have increased significantly.[361] Staff indicates that the number of outages from 2015-2020, many of which were momentary, did not justify the estimated price tag; thus, the Company failed to meet its burden of proving the costs were both just and reasonable. Staff recommended the 69 kV rebuild program be ceased immediately and that alternatives be explored, and that costs related to the program should not be allowed in rates.

Pepco Rebuttal

197. Pepco witness Anthony noted these are not new programs and that the Commission has reviewed them and found them to be prudent in prior rate cases and

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[359] Staff Initial Brief at 8-9 (citation omitted).
[360] Staff Initial Brief at 9-10 (citations omitted).
[361] Staff Reply Brief at 3.

reliability proceedings.[362] He stressed that the program was initiated after the widespread damage and long-duration outages experienced in 2010-2012. Mr. Anthony stressed that some of the subtransmission feeders are strung on wooden poles that are almost 70 years old or share poles with lower voltage distribution lines and as the feeders age, rebuilding the 69kV system is critical to both improving reliability and prevention of widespread outages.[363]

198. Pepco witness Stewart noted that acceptance of OPC's $267.2 million adjustment would discontinue an essential part of the Company's current reliability programs and disallow recovery of two years of investments for expenses already incurred.[364] He explained how Pepco quantified the risk to the 69kV feeders, as well as the project selection process. Pepco witness Stewart found OPC's "risk" approach conflicted with Pepco's requirement to provide reliable service for all customers and would prioritize commercial or industrial customers based on the value of an avoided outage.[365]

199. Additionally, Pepco argued that OPC incorrectly interpreted the Company's risk score. Pepco witness Stewart explained that Pepco evaluates risk based on the probability and consequence of an outage event and the impact to customers. He testified, "Pepco relies on historical 69kV outage data to assign a risk probability of an adverse event occurring along with facility ratings to assign a risk consequence score," and considers the probability of a coincident event occurring at the same time.[366]

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[362] Anthony Rebuttal at 12.
[363] *Id.* at 14-15.
[364] Stewart Rebuttal at 13.
[365] *Id.* at 14-15.
[366] *Id.* at 15.

200. Witness Stewart also noted that the Company performed a comprehensive reliability study for all 69kV overhead feeders in 2014 that considered alternative solutions, including rebuilding the feeders with traditional open-wire overhead construction, underground construction, or Hendrix spacer cable system, and route alternatives.[367] The projects underwent an internal prudency review, and the most cost-effective solutions were selected.

201. Pepco witness Wolverton found that both OPC and Staff incorrectly removed capital expenditures rather than plant closings and failed to properly allocate 69kV sub-transmission projects between D.C. and Maryland by using the Average & Excess – Non-Coincident Peak Ratio.[368]

202. In its brief, Pepco asserted that the intent of the program, which stemmed from Case No. 9240, was to "ensure that at least one hardened 69kV overhead feeder exists to supply each of the Company's critical 69/13kV substations in order to withstand significant weather events."[369] The Company claimed, based on Pepco witness Stewart's rejoinder testimony, that the cost of the 69kV program had actually decreased. Pepco dismissed OPC's contention that non-wires solutions were viable alternatives as unrealistic for such large-scale upgrades.[370] Similarly, the Company found Staff had simply reiterated arguments that the Commission previously rejected. Pepco also rebutted Staff witness Austin's argument that the program did not avoid any customer outages during storms in the 2015-2020 timeframe. Rather, the Company noted that 212

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[367] *Id.* at 16.
[368] Wolverton Rebuttal at 8-11.
[369] Pepco Initial Brief at 24, *citing* Stewart Rebuttal at 31.
[370] Pepco Initial Brief at 26-27.

of 235 outages during that time resulted from weather, equipment failure, vegetation, or unknown causes, all of which the feeder rebuild will reduce.[371]

203. In its reply brief, Pepco highlighted the Enercon study's determination that rebuilding the 69kV feeders was the most cost-effective solution to the outages sustained in 2010-2012.[372] As such, there were no "less expensive options" as advocated by OPC. Despite the expense of this program, the Company noted that if the entire MRP application was approved as filed, "the bill impact to the average residential customer will reflect an average annual increase of only 1.64% since the last rate increase in 2019, through April 2024."[373]

Commission Decision

204. The Commission shares OPC's and Staff's concerns about the ever-increasing budget for this program and disagrees with the Company's assertion that a reduction of the requested capital budget will severely challenge Pepco's ability to meet current reliability standards. In rate cases, utilities are not generally authorized to recover what is requested, dollar-for-dollar. Instead, each utility is awarded a specific revenue requirement after a thorough review of its filing and evidentiary hearings. The Commission uses the ratemaking process to set just and reasonable rates, and the utility must provide safe and reliable service while meeting the applicable reliability standards regardless of whether a revenue increase is awarded or not. Notably, in Pepco's 2017

[371] *Id.* at 27-28, *citing* Stewart Rebuttal at 32.
[372] Pepco Reply Brief at 12.
[373] *Id.* at 15.

rate case, the Company exceeded its reliability targets (in 2018, 2019, and 2020) despite being awarded less than half of the amount requested.[374]

205. This proceeding, although it is a forecasted rather than a traditional rate case, is no different. As discussed below, the Commission will not order Pepco to cease its 69kV rebuild program and will accept Staff's position of allowing recovery only for those projects that are underway. The Company's estimate has increased by over $200 million since its most recent case in 2019 without a reasonable explanation. That increase has created significant questions as to the cost-effectiveness of this program and whether it should continue. Ultimately, Pepco must determine whether it believes the continuation of this program is necessary at its current projected cost. Should Pepco elect to proceed, the prudency of the continued investment in this program will be evaluated in a future rate case. To be clear, the decision whether or not to proceed with this rebuild program is the Company's, and the Commission will not shift the risk of potentially imprudent spending to ratepayers by effectively pre-authorizing rate recovery prior to a full prudency review. Staff's proposal of removing $56.361 million[375] strikes the appropriate balance of allowing recovery for ongoing work while leaving the risks associated with the recovery of future spending on the Company.

206. The Commission acknowledges the difficulties on the utilities, stakeholders, and the Commission that after-the-fact prudency reviews present. The adoption of MRPs has altered the rate-making landscape by allowing greater visibility into utility planning processes and increasing stakeholder engagement. The Commission will carefully

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[374] Hr'g Tr. 124-125 (McGowan) and 161-162 (Anthony), *citing Re Potomac Elec. Power Co.*, Case No. 9443, Order No. 88432 (2017).

[375] *See* Patterson Surrebuttal, Ex. FP-7S. This amount includes Staff's recommended disallowances for both the 69kV Feeder Rebuild Program and the 13kV Underbuild Program.

scrutinize decisions made by utilities, especially for capital projects that run into the tens and hundreds of millions of dollars. The Commission is well aware of, and concerned with, the information asymmetries that have hampered stakeholder input into system planning in the past. Hopefully, the work of the recently launched Distribution System Planning workgroup under PC44 will help to resolve these transparency concerns and aid in deeper reviews of system investment decisions during prudency reviews. At the conclusion of the MRP period, Pepco should be prepared to thoroughly demonstrate the prudence of its decision whether to proceed, or not, with the 69kV rebuild program, as well as any other program or project in this case, based upon its forecasts.

8. Substations

Pepco

207. The Company included three new substation projects in the MRP to address overloads, improve reliability, and serve new load. The construction of the Sligo Substation project began in 2019 to accommodate for an overload on the Parklawn Substation and to improve reliability issues on the Bells Mills Substation 69kV system.[376] This project also improves the reliability of supply to the Linden Substation by converting the feeders to be completely underground.[377]

208. The Parklawn Substation project began in 2020 to accommodate an overload on the substation and improve reliability. The project would also separate the existing 69kV supplies at Parklawn Substation allowing for sectionalization of 69kV feeders. It is anticipated that the project will be in service at the end of 2024.[378]

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[376] Stewart Direct, Sch. (RSS)-1 at 42.
[377] *Id.*
[378] Stewart Direct at 36.

209. The Livingston Road Substation Overload Relief Project was initiated in advance of another phase of commercial development that would require an additional 30 Mega Volt-Amperes ("MVA") to 60 MVA, and Pepco will build a new 69kV/13kV, 80 MVA substation to serve new load in the Oxon Hill/National Harbor area. As part of the project, three 69kV feeders and eight 13kV feeders would be extended to supply the new substation. It was anticipated that engineering would begin in 2022 with construction to commence in 2024, in order to be in service by 2027.[379]

OPC

210. OPC witnesses Alvarez and Stephens recommended removal of the Sligo Substation project from the MRP. They noted that the load growth forecasts for the substation were overblown and failed to materialize.[380] Additionally, they claimed that the Company failed to evaluate the need to resupply the Linden substation and to evaluate alternatives adequately. OPC found Pepco's reliance on an internal standard, which precluded other less expensive options, insufficient compared to National Electrical Safety Code or North American Electric Reliability Corporation (NERC) standards.[381] They similarly found the Parklawn project to be unjustified because Pepco relied upon Montgomery County's 10-year old White Flint area development plan even though the anticipated development had not occurred.[382] OPC would have considered other options, including energy storage and demand response, at a fraction of the project's cost. OPC also claimed that Pepco failed to quantify the reliability risk or the reliability risk

[379] *Id.* at 37.
[380] OPC Panel Direct at 32.
[381] *Id.* at 33.
[382] *Id.* at 34-35

reduction of its design, and the project should have therefore been delayed or avoided.[383] The $161 million project, which is already underway and is one-third complete, should be disallowed, according to OPC.

211. Finally, OPC found the Livingston Road Substation project was also based on anticipated future conditions, but no funds have been spent. Witnesses Alvarez and Stephens cited the impact of the COVID-19 pandemic resulting in slowing load growth and delayed development projects.[384] They stated that delaying the inclusion of this project, at an estimated cost of $48.7 million, would allow stakeholders to address the Livingston Road substation overload risk. OPC's position was that the National Harbor substation may not be necessary or cost-effective and that alternatives may be appropriate.[385]

212. In surrebuttal, OPC continued to find the Company's reliance on load growth forecasts to be inadequate. They explained that the compound annual growth rates were less than 1% and that the growth forecasts indicate a history of decreasing load.[386] Witnesses Alvarez and Stephens similarly discounted the County's plans cited by Pepco as the development has not yet and may never occur; Pepco had not been in contact with the developer for over a year.[387] They also noted that the County's resolution to electrify its vehicle fleet was not the electrification mandate represented by Pepco witness Stewart

[383] *Id.* at 36.
[384] *Id.* at 37.
[385] *Id.* at 37-38
[386] OPC Panel Surrebuttal at 18-19.
[387] OPC Initial Brief at 16-17.

and that “the environmental benefits of electrification assumed by Montgomery County’s sustainability plans require that electricity be generated by renewable means.”[388]

213. OPC explained that the Company provided “no estimate of the reliability risk reductions associated with replacing the 34kV cables and duct banks supplying the Sligo Substation in their capital requirements for the project, nor has Pepco provided such an estimate in discovery.”[389] They cited that the pandemic has changed how people work and shop; shifts in property development have had immediate and long-term impacts that Pepco failed to consider in load forecasts and investment plans.

214. OPC questioned Pepco’s reliance on forecasts to serve future customers without specific information about the nature or needs of those customers.[390] OPC found Pepco’s reliance on dated load growth forecasts and proposed development for areas (White Flint) to be unreasonable and it was not appropriate to require customers to pay for expensive unused infrastructure.[391].

215. OPC criticized the Sligo Substation overflow relief projects as expensive and based on faulty forecasts as load growth did not occur, while the Company declined to explore lower-cost options. Therefore, OPC argues that the Commission should deny recovery of $114.72 million for the Sligo project. Similarly, OPC found that the Parklawn (White Flint) Substation was based on load growth forecasts that did not materialize and that Pepco failed to consider less expensive alternatives.[392] OPC’s recommendation would disallow $161 million of construction costs; they stated that

[388] OPC Panel Surrebuttal at 22.
[389] *Id.* at 23, *citing* Stewart Rebuttal at 9 and Confidential Attach. 1-48.
[390] OPC Initial Brief at 16.
[391] *Id.* at 16-17.
[392] *Id.* at 18.

customers should not bear the full costs of this project as Pepco failed to demonstrate its prudency. However, OPC found that the project could provide some future benefits and therefore only recommended disallowing the costs incurred thus far.

216. Finally, OPC argues that cost recovery for the National Harbor Substation should also be denied due to Pepco's failure to quantify the risks or consider alternatives, and since the growth forecast was not consistent with historical trends.[393] OPC's recommendation is to disallow recovery of $48.7 million for this project. Since the project has not yet begun, there will be no penalty to the Company as a result of the disallowance, according to OPC.

217. In its reply brief, OPC found that the Company's forecasts lacked support and did not justify the need for the Sligo Substation Overload Relief Project. Rather, OPC found Montgomery County's compound annual growth rate was less than one percent, which was comparable to other areas in the region.[394] Again, OPC asserts that Pepco failed to consider any alternatives. OPC found the justification for the Parklawn Project to be based upon Montgomery County's 2010 plan under which the projected development had not occurred. OPC argued that the Company's position was based on speculation and would shift the risk of the project costs to the ratepayers. Finally, they assert that the Livingston Road Project was based upon faulty load forecasts. As the project's in-service date is not until 2028, OPC claimed that sufficient time exists to include the project in the distribution planning process for review; therefore, recovery of these costs should be denied.[395]

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[393] *Id.* at 19-20 (footnotes omitted).
[394] OPC Reply Brief at 7.
[395] *Id.* at 9.

Pepco Surrebuttal

218. Pepco witness Stewart argued that Montgomery County was forecasted to be one of the fastest growing areas in the mid-Atlantic region, and the Sligo Substation project would (1) relieve high loading on substations that serve the area, (2) result in an additional substation, and (3) provide back up for other substations.[396] He testified that the load forecasts were "based on the continuing trend of the rapid development that was occurring in downtown Silver Spring from 2000 to the early 2010s."[397] Further, he argued that OPC's recommendation ignores the project's reliability benefits. Pepco further argued that alternative Sligo Substation upgrades that were identified in 2002, including incremental upgrades to both supplies and transformers, as well as non-wire alternatives, were not feasible.

219. Pepco witness Stewart noted that in 2011, Pepco projected that a new substation at White Flint was necessary for the North Bethesda/White Flint area. Initially, the plan included a supply from the Bells Mill 69kV system and new 69kV supplies to be extended from the Takoma Substation to the Linden Substation. However, Pepco decided that it was more cost-effective to complete the 69kV feeder extensions from Takoma to the Sligo Substation and extend those feeders to supply the Linden substation.[398] The Company argues that the project will create capacity for the White Flint Substation based on the area's load forecast. Pepco witness Stewart asserted that the White Flint Substation's load component reflects the load at the Parklawn Substation

[396] Stewart Rebuttal at 18.
[397] *Id.*
[398] *Id.* at 20.

and was forecasted to exceed its capacity in 2024.[399] He added that the Company's original forecast did not include Montgomery County's mandate for electrification of its vehicle fleet and conversion of buildings from gas to electricity, or urban renewal in downtown Silver Spring.

220. In relation to the Parklawn project, Pepco witness Stewart asserted that the White Flint area was slated for development by the County in a 2010 plan, which was advanced in March 2020 and could involve large developments being constructed in a short time.[400] According to Pepco, the projected rapid growth creates risk for potential non-wires alternatives, which only supply load deferral for a short time. He explained that a substation can take up to four years to construct and therefore provides little room for error. Mr. Stewart stated that several alternatives were considered; none provided the capacity necessary for the projected load growth while reducing the risk of outage to multiple substations.[401] Mr. Stewart claimed the project's risks were properly evaluated and that development of the White Flint area would resume in 2021 or 2022.

221. Finally, Pepco witness Stewart noted that the Livingston Road Substation will be needed by 2028 based on limited backup capability on adjoining feeders during peak or high load conditions, which could impact customers in the Oxon Hill area.[402] The need for this project was identified in 2015 based on Prince George's County's long-range plan for National Harbor. The initial 2027 in-service date was deferred to 2028 as a result of the recently approved battery storage pilot project at the Livingston Road Substation. While there are uncertainties surrounding the long-term effects of COVID-

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[399] *Id.*
[400] *Id.* at 21-22.
[401] *Id.* at 24.
[402] *Id.* at 26.

19, Pepco's sales forecasts anticipate an end to COVID-19 load impacts by December 2021.

222. Pepco argued that the projects were needed based upon anticipated overload conditions and the recognized growth in both Montgomery and Prince George's counties.[403] The Company acknowledged that there is always some uncertainty surrounding such projects; these projects have long lead times and take several years to complete. Pepco identified a risk of installing these projects too late, due to overloads that reduce the life of substation equipment.[404]

223. Pepco defended all three projects and reiterated the need for each. The Company claimed Sligo was necessary based upon load forecasts that take into account each area's development, as well as the need to replace aging lines and cables to improve reliability and increase capacity.[405] The Parklawn Project was necessary to meet load growth requirements, to eliminate overload of the Parklawn Substation and to improve reliability of the Bells Mills system.[406] The Company also cited Montgomery County's White Flint Section Plan that anticipated significant development, which will require additional capacity.

224. The Company defended the Livingston Road project based upon the anticipated growth and development in Prince George's County and claimed that OPC failed to provide any justification to delay construction.[407]

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403 Pepco Initial Brief at 28.
404 *Id.*
405 *Id.* at 29.
406 *Id., citing* Stewart Direct at 36.
407 Pepco Initial Brief at 31-32.

225. In its reply brief, the Company stated that it expects overload conditions to occur if the Commission does not approve funds for the substations. Pepco found OPC's claims that these projects were based on forecasts rather than reliability to be nonsensical as capacity planning is required to maintain system reliability.[408] Similarly, the less expensive options supported by OPC lacked evidence or analysis as to how those options would address the potential overload conditions.

Commission Decision

226. The Commission acknowledges that projects of this type have a lead period of several years, and plans must be undertaken to ensure that a utility can safely and reliably serve future customers. Furthermore, the Commission recognizes that decisions to embark on such large-scale projects must be based on forecasts; the true accuracy of forecasts cannot be determined until *after* the project has been completed. However, these substation projects are costly, and the parties raise significant concerns regarding Pepco's planning and decision-making process.

227. At this time, the Commission will permit the Company to recover the costs it has incurred thus far with the referenced substation projects. However, just as recovery of the 69kV Rebuild Program during the MRP was not pre-approved, the Commission will not pre-approve Pepco recovery of future costs associated with the substation projects during the MRP. The Commission is not sufficiently confident in Pepco's load forecasting, consideration of alternatives, and cost-benefit considerations to allow recovery of such substation construction costs during the MRP. It is important to note that while *reducing* regulatory lag is a result of MRP ratemaking, *eliminating* regulatory

[408] Pepco Reply Brief at 16.

lag is not. The existence of some regulatory lag can serve an important role in a MRP by ensuring that risks for specific projects or activities remain on the utility and its shareholders. With regard to these projects, the Commission's concerns justify placing the risk of non-recovery on the Company.

228. The Commission is not making any determinations as to the accuracy of Pepco's localized load forecasting in relation to the referenced substations. Nor is the Commission opining on the sufficiency of Pepco's distribution planning processes as it relates to the consideration of alternative solutions or cost-benefit analyses. Rather, the Commission is removing the projected budgets for these substations from the MRP revenue requirement without determining whether Pepco should move forward with these projects.

229. As noted in Order No. 89678, "the Commission is not pre-approving any particular work plan or project for purposes of prudency in this Order."[409] Rather, Pepco's proposals and the associated costs will "serve as a guide for prudency both in terms of the individual projects the utility elected to construct and the actual costs of the individual projects when the final reconciliation is performed."[410] In other words, Pepco must make the decision whether to proceed with these projects or not. As previously noted, the Company will be required to thoroughly justify its decisions if it elects to proceed with these projects.

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[409] Order No. 89678 at 96, para. 199.
[410] *Id., citing* MRP Pilot Order at 24.

9. Small Components - Physical Security and Trip Savers Deployment

OPC

230. Witnesses Alvarez and Stephens pointed to the Company's $1.1 million physical security plan for a single substation. While they did not deem that figure to be significant, they were unable to determine if those funds could be spent to address higher priority risks. They found the expenditure to be costly and, if approved, an unwarranted precedent.[411] OPC argued that the risk of service disruption associated with physical substation security was low; furthermore, Pepco does not plan to spend the funds until 2024.

231. OPC also recommended against recovery for the Trip Saver program as the risk reductions did not justify the expenditures. Witnesses Alvarez and Stephens noted that the 146 Trip Saver devices the Company installed in 2020 cost $2.2 million.[412] Since Pepco began this program in 2015, the Trip Savers only tripped 140 times; 129 devices locked out just as a fuse would have done. OPC found that the program only avoided 11 outages that lasted 30 minutes and affected 30 – 50 customers each.[413] Therefore, OPC concluded that the risk reduction did not justify the cost.

232. In surrebuttal, Witnesses Alvarez and Stephens maintained that the risk to the physical security of substations was "extremely low" and constituted a solution in search of a problem.[414] In relation to the Trip Savers, they accepted the Company's representation that the outages avoided by the operation of a Trip Saver was likely longer

[411] OPC Panel Direct at 39.
[412] *Id.* at 16.
[413] *Id.*
[414] OPC Panel Surrebuttal at 28.

than 20-30 minutes; however, they continued to believe that the 11 outages avoided by the devices was not worth the $2 million price tag.[415]

233. In its brief, OPC stressed that the risk to substation security was very low and that the Company failed to quantify the risk of physical disruptions.[416] OPC claimed this issue would be better considered in a distribution planning process outside of the rate case process. The Trip Saver program also suffered from a lack of quantification of the risk reduction, which made the evaluation of the $2.2 million price tag difficult.[417] As only 140 of the Trip Savers activated, OPC concluded that the cost of the program does not justify the risk reduction.

234. In response to Pepco, OPC continued to argue that there was a lack of evidence substantiating that the costs of substation security and the Trip Savers.[418]

Staff

235. Staff witness Austin initially questioned the costs of the Trip Savers program; however, in surrebuttal, he withdrew his objection to the program based upon the Company's representation that it did not plan to fund the program in the 2020-2023 budget without first evaluating the effectiveness of the program.[419]

Pepco

236. Pepco witness Stewart indicated that Pepco's plan to protect its critical infrastructure was well-balanced and that the U.S. Departments of Energy and Homeland

[415] *Id.* at 29.
[416] OPC Initial Brief at 14.
[417] *Id.* at 15.
[418] OPC Reply Brief at 10.
[419] Austin Surrebuttal at 7.

Security noted that security risks to the electric grid are a national issue.[420] Additionally, he stated, "NERC CIP 014-1 (See Schedule (RSS-R)-9) outlines the physical security requirements approved by the Federal Energy Regulatory Commission for transmission substations."[421] As the Company's substations provide service to critical facilities, Mr. Stewart claimed it was prudent to manage security risks.

237. In relation to the Trip Savers program, Pepco witness Stewart claimed that they have been installed at 159 locations and operated at 59 of those locations a total of 253 times, avoiding 156 sustained outages and 20,569 customer interruptions.[422] He provided the SAIFI reductions resulting from this program and noted the national trend for the last 10 years has been to replace fuses with Trip Savers. Pepco witness Stewart disputed OPC's claim that Trip Savers cost $15,000 per installation and asserted that the actual cost was approximately $6,000 per installation. He also noted that OPC's claim that Trip Savers activated only 11 times for 20 minutes was conjecture based on OPC witness Alvarez's experience rather than Pepco's service area.[423]

238. In its brief, the Company stressed that the physical security of the electric grid has become a national issue and noted Pepco witness Stewart's testimony that break-ins are occurring to steal commodities, damage equipment, and access cyber systems.[424] Pepco argued that Witnesses Alvarez and Stephens lack security expertise or background and

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[420] Stewart Rebuttal at 27-28.
[421] *Id.* at 28.
[422] *Id.* at 34.
[423] *Id.* at 34-35; *see* Schedule (RSS-R)-13.
[424] Pepco Initial Brief at 33-34, *citing* Stewart Rebuttal at 28.

are not familiar with the Company's service territory or the risks it faces, and therefore OPC's position is baseless.[425]

239. Pepco also maintained that the Trip Saver program was an "overwhelming success" as the Trip Savers avoided 140 sustained outages resulting in the avoidance of over 20,000 customer interruptions.[426] The Company claimed OPC's position was based on incorrect calculations and inflated per-installation costs.[427]

240. Pepco continued to assert that OPC's position is baseless as both the U.S. departments of Energy and Homeland Security have referenced the risks of break-ins to substations, and that the investments will be made throughout the MRP, not just in 2024 as alleged by OPC.[428] In relation to the Trip Savers, the Company indicated that OPC ignored Staff's testimony related to the program's success.

Commission Decision

241. Based on the record regarding Trip Savers and Substation physical security, the Commission declines to accept OPC's adjustments. The Commission finds the record supports Pepco's positions. Pepco demonstrated that the risks to the physical security of substations is a national security issue. Additionally, the Commission agrees that OPC's adjustment on the Trip Savers was based on miscalculation and finds that the Trip Savers have resulted in significant avoided outages. Furthermore, the Commission agrees with the Company as to the importance of these programs, both of which have relatively small expenditures. The Commission is also persuaded that, in the context of a MRP, OPC's adjustments appear to be an attempt to micromanage utility operations. Furthermore, the

[425] Pepco Initial Brief at 34.
[426] *Id.* at 35, *citing* Stewart Rebuttal at 34 and Austin Surrebuttal at 6-7.
[427] Pepco Initial Brief at 35-36, *citing* Stewart Rebuttal at 34.
[428] Pepco Reply Brief at 19.

recently launched distribution planning workgroup may be a better forum for exploring broader issues related to cost-effective spending and risk-reduction valuation.

10. <u>Contingencies</u>

Staff

242. Staff witness Patterson adjusted Pepco's contingencies in accordance with Order No. 89678, in which the Commission determined "that it would be inappropriate to require customers to pay for overrun costs upfront prior to a prudency review."[429] Staff's adjustments resulted in a reduction to rate base in MRP 2022 ($3,765,000), MRP 2023 ($6,713,000), and MRP 2024 ($8,075,000).[430]

243. In surrebuttal, Staff witness Patterson upheld that Staff's adjustments were consistent with Order No. 89678. However, Mr. Patterson increased Staff's adjustments as follows: MRP 2022 ($6,351,000); MRP 2023 ($11,613,000); and MRP 2024 ($14,244,000).[431]

244. Staff claimed its position was consistent with Case No. 9645. In response to Pepco, Staff continued to claim that ratepayers should not pay for project overruns prior to a prudency review and that its position was consistent with Case No. 9645.[432]

Pepco

245. Pepco witness Stewart explained that project managers identify execution risks for each project and assign a contingency reserve to each execution based on incremental cost and probability of occurrence during execution.[433] He indicated that the contingency

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[429] Patterson Direct at 14, *citing* Order No. 89678 at 43-44, para. 90.
[430] Patterson Direct at 14-15 and Ex. FP-8.
[431] Patterson Surrebuttal at Ex. FP-8S.
[432] Staff Reply Brief at 6, *citing* Order No. 89678 at 43-44.
[433] Stewart Rebuttal Testimony at 49.

amounts are refined when authorization is sought and can include preliminary or detailed engineering designs, the required permits, and construction specifications.

246. In its briefs, Pepco relied on witness Stewart's testimony that the capital budget contingencies were reflected in the actual costs of capital projects.[434] The Company asserted that since its contingency budgets were prudently created and were expected to support projects, this issue is distinguishable from the Commission's decision in Case No. 9645.[435] Pepco continued to argue that Staff's position should be rejected as the Company's budgets were "based on actual project execution experience and anticipates utilizing its budgeted contingencies to support the projects being executed."[436]

Commission Decision

247. In Order No. 89678, the Commission removed contingency amounts in BGE's capital budgets and found that "it would be inappropriate to impose on ratepayers the additional costs of funding a cushion above BGE's best estimate."[437] In this case, Pepco claimed that its contingencies are reflected in the actual costs of capital projects and therefore the Commission should distinguish its situation from the BGE case. The Commission questions how such funds can be defined as contingencies when Pepco fully expects them to be used to support projects.[438] Such an approach runs counter to the definition of contingency: "an event (such as an emergency) that may, but is not certain

[434] Pepco Initial Brief at 41, *citing* Stewart Rebuttal at 49.
[435] Pepco Initial Brief at 42.
[436] Pepco Reply Brief at 22 (footnote omitted).
[437] Order No. 89678 at 43, para. 90.
[438] *See,* Pepco Initial Brief at 42 and Hr'g Tr. 351-353 (Stewart).

to, occur."[439] Accordingly, the Commission directs Pepco to remove contingencies from its capital budget.

11. Vegetation Management

Staff

248. Staff witness Austin indicated that Pepco's vegetation management costs are the highest of the six major utilities in Maryland and expressed concern about the rising costs and lack of transparency in justifying those costs.[440] Based upon discovery responses, Mr. Austin anticipated that the Company's costs would have minimally increased based upon the projected trim mileage per year, but he found, "the annual cost increases of the Company's new vegetation management contract do not seem to match the projected miles of circuit on which vegetation management will be performed."[441] Therefore, he recommended that Pepco's 2019 costs be used as a baseline and that the recovery of any increases be limited to the rate of inflation.

249. Based on Staff witness Austin's recommendation, Staff witness Patterson made adjustments to operating income for vegetation management by disallowing O&M costs in MRP year 1 ($1,803,000) and MRP year 2 ($2,056,000). The net adjustment after allowing for State and federal income taxes for operating income for MRP Year 1 was $1,307,000 and for MRP Year 2 was $1,490,000.[442] Mr. Patterson did not make an adjustment for MRP Year 3.

250. In surrebuttal testimony, Staff witness Austin calculated what he believed to be a reasonable estimate for the 2020-2023 vegetation management schedule based on

[439] https://www.merriam-webster.com/dictionary/contingency.
[440] Austin Direct at 34.
[441] *Id.* at 35.
[442] Patterson Direct at 20-21 and Ex. FP-13.

discovery responses, which described a yearly variance based on the four-year trim schedule. He used an inflation adder developed from Congressional Budget Office wage inflation data.[443] Mr. Austin's calculations differed by $2.1 million from Pepco's figures. Despite Pepco's explanation that vegetation management work is competitively bid across the Exelon Utilities, Mr. Austin maintained that a disallowance of $2.1 million is appropriate.[444]

251. With a $2.1 million disallowance from the requested $81.13 million, Staff concluded that $79.003 million was an appropriate amount for Pepco's vegetation management during the MRP. In its reply brief, Staff argued that while Pepco's costs were not necessarily excessive compared to other Maryland utilities, the costs were excessive compared to the Company's *own* costs in preceding cycles.[445]

<u>*Pepco*</u>

252. Pepco witness Wolverton noted that Staff's adjustment was based upon Staff witness Austin's "own 'implied' MRP amounts based on 2019 Actual data and the project annual percent increase per the new VM contract."[446] He indicated that the MRP revenue requirement did not reflect those figures and that the adjustment was overstated.

253. Pepco witness Stewart noted that while Pepco may have the highest vegetation management costs among Maryland utilities, he believed it was inappropriate to simply compare utilities as each service territory is different. Additionally, Mr. Stewart indicated that Staff acknowledged in a June 18, 2020 hearing in Case No. 9353 that a per-

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443 Austin Surrebuttal at 11.
444 *Id.* at 12.
445 Staff Reply Brief at 9.
446 Wolverton Rebuttal at 14.

mile analysis can be difficult because the utilities may not have been reporting "all-in" vegetation management costs.[447]

254. Pepco noted that the Vegetation Management Cost Work Group ("VMCWG") Report determined that Pepco is the only utility required to perform log removal as a condition to acquire permits for routine vegetation management—a cost driver not incurred by other utilities.[448] The VMCWG also found that the Company is the only utility required to conduct wetland delineations, and that Pepco, unlike BGE, provides tree replacements.

255. Pepco witness Stewart highlighted that the Commission recognized decreases in the Company's vegetation management costs from 2018 to 2019,[449] and again in 2020. He asserted that the $2,700 reduction per mile from 2019 to 2020 was evidence of Pepco's prudent management of vegetation management costs.[450] Mr. Stewart described the competitive bid process and cited rising labor costs as the basis for the contract increases. Additionally, the characteristics of the feeders being maintained differ from year to year based on topography, vegetation condition, and work conditions.

256. Pepco claimed Exelon's competitive bid process, which contracts on a "per unit basis," was the most cost effective method "because it allows for 'an independent third party' who 'actually surveys and controls the feeders in advance of the work and comes back with recommendations on what work needs to be done.'"[451] The Company asserted that Staff's position that costs were unreasonably high was flawed because it disregarded

[447] Stewart Rebuttal at 38, *citing* Order No. 89629, para. 47.
[448] Stewart Rebuttal at 39, *citing* Maillog No. 233700 at 5.
[449] Stewart Rebuttal at 40, *citing* Order No. 89629, para. 46.
[450] Stewart Rebuttal at 41.
[451] Pepco Initial Brief at 40, *citing* Hr'g Tr. 289-291 (Stewart).

the results of the competitive bid process, increases in labor rates, and the fact that per-mile costs have been decreasing.[452]

Commission Decision

257. The Commission consistently has expressed concerns regarding the costs of Pepco's vegetation management program. In its 2019 review of electric service reliability, the Commission noted the Company's relatively high per-mile cost and stated, "it is the Commission's expectation that as Pepco renegotiates its vegetation management contracts during the Exelon-wide renegotiation process, its costs will become less of an outlier when compared to the other Electric Companies in Maryland."[453]

258. Thus far, the benefits from the Exelon-wide renegotiation process are not readily apparent, and Pepco witness Stewart's responses to the Commission's inquiries were less than illuminating. He reiterated that the contract was competitively bid and that mutual assistance crews could be used if necessary,[454] that merger savings were not reflected in his testimony, that vegetation management costs were increasing over the MRP time period, and that vegetation management costs were embedded as part of preventative maintenance in his testimony.[455]

259. However, based on the record in this case, the Commission finds that since the contract was competitively bid for costs that will be incurred, it would not be appropriate to accept Staff's proposed disallowance. Tree trimming is a necessary utility function that Pepco will perform during the MRP period. The actual costs that Pepco will incur

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[452] Pepco Initial Brief at 40-41, *citing* Hr'g Tr. 1068-1069 (Austin).
[453] *In the Matter of the Review of Annual Performance Report on Electric Service Reliability Filed Pursuant to COMAR 20.50.12.11*, Case No. 9353, Order No. 89260 (Sep. 26, 2019) at 19.
[454] Hr'g Tr. at 336-337 (Stewart).
[455] Hr'g Tr. at 343-344 (Stewart).

are in the record. While Staff may believe those costs are higher than other utilities' costs, Staff does not dispute that Pepco will need to pay the contracts as agreed. The Commission recognizes that Pepco has certain vegetation management-related costs, *i.e.*, log removal, wetland delineations, and tree replacements, that not all Maryland utilities incur. While it is difficult to compare the utilities on an apples-to-apples basis, different requirements do not necessarily mean higher costs. The Commission will continue to closely monitor the Company's vegetation management costs, and Pepco is directed to provide additional information as to the impact of merger savings and cost-control measures on this issue in future proceedings.

12. Wages and Salaries

OPC

260. Based on discovery, the Company's employee headcount as of December 31, 2020, was 1,456 versus the forecasted 1,537 -- a difference of 81 employees.[456] OPC witness Effron found that Pepco's employee levels remained relatively flat over the last four months of 2020. The projected employee level for MRP Year 1 was forecasted to be 1,528, which drops to 1,499 with the exclusion of 29 temporary employees; this represents a difference of 43 employees versus the actual number as of December 31, 2020.[457] OPC witness Effron proposed a reduction in wages and salaries by $1,182,000 and in payroll taxes by $68,000, for a total reduction of $1,250,000 in Year 1 before income taxes.[458] In Year 2, he proposed a reduction of wages and salaries by $995,000 and in payroll taxes by $57,000, for a total reduction of $1,053,000 in expenses before

[456] Effron Direct at 13.
[457] *Id.* at 14.
[458] *Id.* at 15.

income taxes.[459] Finally, in Year 3, OPC witness Effron proposed to reduce wages and salaries by $861,000 and payroll taxes by $50,000, for a total reduction of $911,000 in expenses before income taxes.[460]

261. OPC witness Effron maintained his position in surrebuttal. Based on discovery, he found that the Company filled 13 vacancies in the Customer Operations department; however, this did not lead to a net increase in the employee complement from December 31, 2020 to March 31, 2021.[461] While he did not dispute the Company's intention to fill the positions, Mr. Effron pointed out that the Company provided no evidence that the forecasted increase was taking place.

262. In its brief, OPC maintained its position and its recommended pre-income tax adjustments to payroll expenses for each of the MRP years.[462] In its reply brief, OPC maintained that its adjustments were necessary to ensure that the Company's rates were just and reasonable. While acknowledging the need to rely on forecasts, OPC asserted that actual numbers should be relied upon when available.[463] OPC claims that when Pepco's actual numbers from December 31, 2020 are compared to March 31, 2021, the evidence does not support the Company's forecasted employee increase.[464]

Pepco

263. Pepco witness Barnett disagreed that the actual 2020 headcount would be permanent during the MRP because Pepco planned to fill the positions, which were deemed critical for Customer Operations and Transmission and Substation responsibility

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[459] *Id.*
[460] *Id.,* and DJE Schedule C-1.
[461] Effron Surrebuttal at 9.
[462] OPC Initial Brief at 10.
[463] OPC Reply Brief at 11.
[464] *Id.* at 11-12.

areas.[465] Pepco witness Stewart added that OPC's proposal to reduce the Company's headcount by 16 in the Transmission and Substation responsibility area would impact the ability to meet customer expectations "by impeding successful and safe completion of projects aligned with maintaining and upgrading the Company's electric distribution system."[466] He explained that Pepco intended to fill the vacancies and was actively interviewing and hiring for the open positions.

264. Pepco witness Bell-Izzard also found that OPC witness Effron's adjustment was overly simplistic and failed to account for the Company's hiring process for the Customer Operations Department.[467] She indicated that the main driver of the variance was hiring delays and that 27 full-time employees will be hired by mid-2021.

265. Pepco argued that the open positions are critical roles.[468] The Company found OPC's position unreasonable, unwarranted, and incorrect.[469]

<u>Commission Decision</u>

266. The Commission accepts Pepco's commitment that it intends to fill its open positions and acknowledges that the COVID-19 pandemic has affected the labor market in significant and unpredictable ways. The Company does not fill the positions in question, ratepayers shall not pay for expenses relating to those positions. Nevertheless, the Commission believes this issue is best left to the MRP's reconciliation process. Therefore, the Commission denies OPC's proposed adjustment.

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465 Barnett Rebuttal at 15.
466 Stewart Rebuttal at 45.
467 Bell-Izzard Rebuttal at 7.
468 Pepco Initial Brief at 43, *citing* Wolverton Direct at 42.
469 Pepco Reply Brief at 23.

13. Exelon Separation Transaction

Pepco

267. Pepco witness McGowan noted that on February 24, 2021, Exelon announced a plan to separate Exelon Utilities, including Pepco, from Exelon Generation, Exelon's competitive retail energy and merchant generation business.[470] He anticipated that the transaction would not impact Pepco's operations and that rates would not change as a result. Mr. McGowan testified, "Pepco expects its risk profile to remain similar once the Separation Transaction is complete. Pepco does not anticipate any changes to its credit rating by any of the credit rating agencies."[471]

Staff

268. Staff witness Patterson recommended that Pepco should keep the Commission informed as the transaction progresses and provide a report when it is finalized. The report should include, but not be limited to, any impacts on the Company's operations and should identify potential impacts on rate base or operating income as part of the MRP's informational filings and reconciliations.[472]

Commission Decision

269. The Commission finds Staff's recommendation to be reasonable. Therefore, Pepco is directed to provide updates regarding the Exelon Separation Transaction as it progresses and advise the Commission when the transaction is finalized, as discussed in

[470] McGowan Rebuttal at 2-3.
[471] *Id.* at 4.
[472] Patterson Surrebuttal at 5-6.

Staff witness Patterson's surrebuttal testimony.[473]

14. Distribution Planning

Pepco

270. Pepco witness Barnett explained that PHI's Long-Range Plan ("LRP") includes five years of forecasted O&M costs, in order to plan for future expenditures and manage costs; it also includes capital spend, financial statements, and financial metrics. He testified, "The operational plan includes goals that strive toward achieving industry-leading safety and operational performance for both reliability and customer satisfaction."[474] According to Mr. Barnett, the financial plan includes spending targets to achieve operational goals, to comply with regulatory requirements, and to ensure that overall O&M expense increases are lower than the rate of inflation.

271. Witness Barnett explained that in developing the LRP, consolidation of inputs are provided by responsibility area, with each one reviewing historic expense levels, performance assessments, regulatory requirements, operational goals, specific projects, and a myriad of other factors. In addition, Mr. Barnett stated that each responsibility area provides its LRP to the Finance responsibility area, where it is analyzed for consistency, completeness, and appropriateness.[475] Furthermore, each responsibility area performs its budget and planning process based on its business needs, upcoming projects, existing or new initiatives, regulatory/legal requirements, and established targets. The Company determines the level of resources required to achieve and fund the business needs after

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[473] The Commission will review the Transaction as part of Case No. 9271 where Monitoring Analytics has requested that the Commission maintain certain behavioral rules to protect against undue market power. Additionally, the Commission has intervened in Federal Energy Regulatory Commission (FERC) Docket EC21-57, in which Exelon is seeking approval of its generation spin-off application.
[474] Barnett Direct at 5.
[475] *Id.* at 6.

analyzing historical spending levels, while considering underlying major cost drivers and developing an assessment of future requirements.[476] Pepco witness Barnett testified that Pepco incorporates financial guidelines in the planning process to achieve operational efficiencies and other business-related savings into its plan to keep O&M cost increases below the inflation rate. Cost projections are developed for both Pepco and Pepco Holdings, Inc. Service Company (PHISCO) as to how costs are incurred by the various responsibility areas.

272. Pepco witness Barnett testified that while budgets developed through the LRP process are attainable, they are "somewhat aggressive" and the actuals may be higher or lower depending on modifications to spending, which aim to meet changing business needs.[477] He noted that the Company's 2018 actual costs were 3.5% higher than budgeted, primarily due to higher contracting costs for additional corrective maintenance; and the Company's 2019 actual costs were 2.0% lower than budgeted due to lower base payroll and overtime costs.[478]

273. In this case, Pepco did not use its LRP and instead relied upon six months of actuals and six months of projections because that cost data provided the most recent view of O&M to explain the year-over-year changes to the MRP projections for 2021-2024.[479] Mr. Barnett indicated that COVID-19 impacted O&M due to new costs for items such as masks and cleaning supplies, as well as the moratorium on disconnects—all of which the Company has excluded from the MRP projections and placed into a regulatory asset. Mr. Barnett testified that the Company "develops an O&M LRP so that

[476] *Id.* at 7.
[477] *Id.*
[478] *Id.* at 7-8.
[479] *Id.* at 8.

its annual year-over-year increases are at a rate lower than inflation." Based on Pepco's analysis, its projected O&M Compounded Annual Growth Rate percentages are 1.1% for 2019-2024, 1.6% for 2020-2024, and 0.6% for 2021-2024, all of which are significantly below expected inflation rates.[480]

274. Pepco witness Stewart explained that PHI updates its LRP each year; for the 2020-2024 LRP, the planning cycle occurred in spring 2019.[481] He explained that prioritization decisions were based on a review of project risks and opportunities, such as reliability, environmental and safety risk, and impacts to the distribution system. He noted that Pepco's process aims to ensure that adequate infrastructure exists to supply electric service for all customers at a reasonable overall cost, consistent with goals regarding safety, reliability, quality of service, community relations, and protection of the environment. He stated that the Company reviews the five-year plan to verify the timing of projects needed to supply customer load or address system performance issues. Mr. Stewart described the major components of the system planning criteria, including: (1) maintaining appropriate voltage and reactive support; (2) operating within maximum rating of facilities; and (3) increasing the reliability of the electric system.[482]

OPC

275. OPC found that of 123 investor-owned utilities that have reported financial data on FERC Form 1 since 2010, Pepco had the highest gross distribution rate base per customer at $8,386.[483] Witnesses Alvarez and Stephens determined that the Company's rate base per customer was more than 22% higher than that of the next highest utility,

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[480] *Id.* at 9.
[481] Stewart Direct at 38.
[482] *Id.* at 39.
[483] OPC Panel Direct at 9.

Consolidated Edison. They found it difficult to determine why that figure was so high but opined that part of the reason was that Pepco's distribution planning and investment process was biased in favor of capital investment.[484] Witnesses Alvarez and Stephens noted several deficiencies in the Company's process, namely the use of qualitative rather than quantitative approaches; inadequate identification of alternatives to Company capital; and inadequate evaluation of available alternatives on a "risk reduction per dollar" basis.[485]

276. OPC found that the Company's approach to the distribution plan was based upon subjective estimates, rather than historical data, to assign a probability to an adverse event.[486] They pointed out that Pepco's estimates related to the 69kV rebuilds did not account for actual risk levels, particularly since substations were hardened following the 2010-2012 storm years. Witnesses Alvarez and Stephens characterized Pepco's probability estimates as unrealistic and its failure to consider alternatives—or the rejection of alternatives due to treatment as operating expenses rather than capital expenditures—to be inappropriate.[487] For these reasons, they recommend a proceeding to develop a distribution planning process.

Pepco Rebuttal

277. In his rebuttal testimony, Pepco witness Stewart disagreed with OPC's claim that the Company's process was biased towards capital. Mr. Stewart argued that OPC erred in its calculations by using gross distribution rate base per customer and counting Pepco's

[484] *Id.* at 10.
[485] *Id.* at 11.
[486] *Id.* at 17.
[487] *Id.* at 22-23.

entire service territory (both the District of Columbia and Maryland).[488] He also dismissed OPC's claim that the Company's process lacked transparency and stated that the process was designed to address system needs and promote affordability.[489] Mr. Stewart indicated that Pepco would participate in a working group to consider changes to the planning process.

278. Pepco witness Wolverton found OPC's claims to be misleading as its Panel relied upon "gross distribution rate base," when in fact they meant gross distribution plant; additionally, their calculations were on a Pepco level rather than a Pepco-Maryland level.[490] When recalculated based on Pepco-Maryland, the gross distribution plant per customer was $6,039, or 12% less than Consolidated Edison, according to Pepco.[491] Mr. Wolverton also noted that gross distribution plant did not reflect actual rate base. In his rebuttal testimony, Pepco witness Stewart disagreed with OPC's claim that the Company's process was biased towards capital. In addition to calculation errors (using gross distribution rate base per customer), OPC acknowledged that it did not complete a Pepco-MD specific calculation.[492] Pepco also dismissed OPC's claim that there was a lack of transparency in the Company's process used to address system needs and achieve affordability for customers.[493] However, Pepco witness Stewart indicated that Pepco would participate in a working group to consider changes to the planning process.

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[488] Stewart Rebuttal at 9, *citing* DR 4-2 to OPC.
[489] Stewart Rebuttal at 9-10.
[490] Wolverton Rebuttal at 32.
[491] *Id.* at 32-33.
[492] Stewart Rebuttal at 9, *citing* DR 4-2 to OPC.
[493] Stewart Rebuttal at 9-10.

Commission Decision

279. The Commission makes no determination regarding the adequacy or quality of Pepco's distribution system planning processes. However, the Commission agrees that a workgroup to explore distribution system planning approaches for all utilities is necessary and notes that the recently launched Distribution System Planning Workgroup under PC44 will focus on ways to increase the transparency of, and stakeholder engagement in, each utility's planning process.

15. Non-Labor O&M Inflation Adjustment

Pepco

280. Pepco witness Merchant explained that the non-labor O&M inflation adjustment was approved in a prior Pepco rate case, Case No. 9602. In that case, RMA 19 adjusted the historical test year (HTY) non-labor O&M expense for the impacts of price inflation based on the five-year average Consumer Price Index (CPI) for the DC-VA-MD-WV region for the years 2016-2020, as measured by the U.S. Department of Labor's Bureau of Labor Statistics.[494] The adjustment would reduce operating income for the HTY by $1.221 million.

AOBA

281. AOBA witness Timothy Oliver explained that the Company sought recognition of a $1.221 million adjustment to the non-labor component of its distribution O&M expense, which decreases the HTY operating income by the same amount.[495] While this adjustment was accepted in Case No. 9602 and BGE's MRP case, he claimed that Pepco provided no justification to support the adjustment in this case. Mr. Oliver suggested that

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[494] Merchant Direct at 15.
[495] T. Oliver Direct at 30.

there were many non-inflation-related factors that will influence these expenses. He also suggested that the Gross Domestic Product ("GDP") Price Index, which Pepco used to estimate the influence of inflation on its non-labor distribution O&M expenses, was based upon goods and services that Pepco likely would purchase on an annual basis.[496] Mr. Oliver found no correlation between the Company's actual operating experience and the calculated changes in the GDP Price Index.

282. AOBA argued that this adjustment should be denied because: the Company failed to address the diverse nature of costs that the adjustment would apply to; that, historically, inflation was not the most important driver of changes in the components of Pepco's Non-Labor O&M cost; and costs of the major components may decrease during the MRP.[497] AOBA found that the labor component of the Company's O&M expenses increased at more than twice the rate of its overall O&M expenses; thus the non-labor O&M costs must be decreasing.[498] AOBA claimed that Pepco failed to provide any information related to the change in composition of its non-labor O&M costs or why the costs have increased.

Pepco Rebuttal

283. Pepco witness Wolverton explained that this adjustment was approved in Case No. 9602 and was therefore included in the HTY revenue requirement in this case.[499] He indicated that the Gross Domestic Product Price Index, which was a main component of

[496] *Id.* at 32.
[497] AOBA Brief at 28-29.
[498] *Id.* at 29.
[499] Wolverton Rebuttal at 20 (footnote omitted).

AOBA's criticism, was not used in this adjustment and that even if the adjustment was accepted, it would have no impact on the MRP revenue requirement.[500]

284. In its reply brief, the Company asserted that the adjustment only applied to the HTY and not the MRP period.[501] Pepco cited Staff's testimony that noted the HTY only served as a point of reference for each year in the MRP; the adjustment was approved and based on precedent and was properly included in the HTY revenue requirement.[502]

Commission Decision

285. After reviewing the record, the Commission agrees with Pepco's position. This adjustment is simply a point of reference for the HTY and has no impact on Pepco's revenue requirement during the MRP. While the Commission specifically authorized BGE's 2.5% per year inflation forecast for non-labor inflation, that adjustment was for the 2021 to 2023 MRP period, not the HTY.[503] Therefore, AOBA's adjustment is denied.

16. Baseline Distribution Revenues for Schedules R and RTM

Pepco

286. Pepco's filing includes customer counts and sales volumes for the Company's Schedule R and RTM classes. While Pepco opposed OPC's customer charge adjustments related to Schedules R and RTM, the Company did not oppose Staff's recommendations regarding revenue-related adjustments related to Schedules R and RTM.

[500] *Id.*
[501] Pepco Reply Brief at 21, *citing* Wolverton Rebuttal at 20.
[502] Pepco Reply Brief at 22.
[503] *See* Order No. 89678 at 61.

Staff

287. Staff witness Hoppock noted that the Schedule R customer counts have steadily increased over the past 10 years, while "Schedule RTM customer counts have stayed roughly flat or declined gradually over the past 10 years, and Schedule RTM sales have declined at faster rate than Schedule R sales."[504] Mr. Hoppock recommended that the Commission require Pepco—in any future case—to use separate models to forecast Schedule R and Schedule RTM sales and customer counts.[505] Based on Mr. Hoppock's comments regarding Schedules R and RTM in this case, Staff witness Patterson proposed Baseline Distribution Revenues for Schedules R and RTM. Mr. Patterson updated this proposed adjustment in his surrebuttal exhibit, Ex FP-3S.

Commission Decision

288. The Commission finds that Staff's analysis regarding Schedule R and RTM customer counts and sales is persuasive and therefore adopts Staff's recommendations: (a) to adjust the Company's revenues as recommended by Staff witness Patterson, and (b) to direct Pepco to use separate models to forecast Schedule R and RTM sales and customer counts in future cases.

B. Cost of Capital

289. The cost of capital is the rate of return ("ROR") that a utility pays investors in common stock (equity) and bonds (debt) to attract and retain investment in a financially competitive market. The utility recovers its return on equity ("ROE") and cost of (or return on) debt through charges paid by its ratepayers. While the cost of debt can be directly observed, as bonds are issued subject to specific interest rates, this rate case

[504] Hoppock Direct at 23.
[505] *Id.* at 25.

features competing recommendations regarding whether Pepco's cost of debt should remain static over the three-year MRP effective period or be adjusted downward based on a historical analysis of the company's cost of debt from prior rate cases.

290. The ROE also requires analysis, as it is typically estimated based on market conditions and different analytical approaches. Once the cost of debt and ROE are determined, they are weighted according to the percentage of debt and equity in the utility's capital structure. The sum of the weighted cost of debt and ROE is the utility's overall ROR. Although Pepco is a subsidiary of Exelon, and thus its stock is not publicly traded, the Commission still must examine Pepco's level of risk and its capital structure (compared to comparably situated companies) to determine its cost of capital.

291. In this case, testimony on cost of capital was presented from witnesses for Pepco, Commission Staff, OPC, and AOBA. The parties recommended the following ROEs (Table 5):

Table 5
ROE Range by Party

Party	ROE Range	ROE Recommendation
Pepco	9.5% – 10.8%	**10.2**%[506]
Staff	8.89% - 9.69%	**9.4** %[507]
OPC	7.30% - 9.05%	**9.0** %[508]
AOBA	8.26% - 9.26 %	**9.25**%[509]

506 McKenzie Direct at 36.
507 McAuliffe Direct at 59.
508 Woolridge Direct at 5.
509 T. Oliver Direct at 9.

292. In support of their recommendations, the Parties presented competing quantitative analyses, which involved comparing Pepco to other utilities for the purposes of developing a proxy group. The Parties disagreed on the significance of recent economic data and the impact of the COVID-19 pandemic on future investor expectations. While the Parties generally did not dispute Pepco's proposed capital structure, certain Parties raised concerns.

1. <u>Proxy Groups</u>

293. As part of their analyses, the Parties attempted to create proxy groups of companies with comparable risk to Pepco's electric distribution business.

<u>Pepco</u>

294. Pepco witness Adrien McKenzie created an electric-specific proxy group of 23 electric utilities that he referred to as the "Electric Group."[510] Witness McKenzie used the following criteria to identify his proxy group utilities: (1) inclusion in the Electric Utility Industry groups compiled by Value Line; (2) payment of common dividends over the last six months and no announcement of a dividend cut since that time; (3) no ongoing involvement in a major merger or acquisition that would distort quantitative results; (4) a Value Line Safety Rank of "1" or "2"; and (5) a Value Line Financial Strength Rating of "B++" or higher.[511] Witness McKenzie also said that his analysis considered credit ratings from S&P and Moody's in evaluating relative risk. Specifically, his analysis excluded any companies with ratings more than one "notch" lower than

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[510] McKenzie Direct at 6. Witness McKenzie also created a separate proxy group comprised of companies in the competitive sector--*i.e.*, a Non-Utility Group. Witness McKenzie did not, however, rely on this group to inform his ROE recommendation. *Id*. at 50.
[511] *Id*. at 5.

Pepco's credit rating of A- and Baa1 assigned by S&P and Moody's, respectively.[512] Witness McKenzie also evaluated investors' risk perceptions for the Electric Group by looking at Value Line's primary risk indicator of Safety Rank, Value Line's Financial Strength Ratings and, finally, beta, which measures a utility's stock price volatility relative to the market as a whole and reflects the tendency of a stock's price to follow changes in the market.[513] Based on his analysis, Mr. McKenzie stated that a comparison of these risk indicators between his proxy Electric Group and Pepco shows that "investors would likely conclude that the overall investment risks for the firms in the Electric Group are comparable to Pepco."[514]

Staff

295. Staff witness Drew McAuliffe identified a proxy group of 31 companies that are identified as electric utilities by Value Line.[515] His proxy group was restricted to companies with a VL financial strength rating of B++ or greater. Using B++ as the minimum VL strength rating would exclude companies that might be experiencing financial difficulty, while not restricting the Proxy Group to companies with the highest ratings.[516] He required each company to have all relevant data necessary to conduct the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") methods.[517] He excluded Pepco's parent company, Exelon Corporation and any utility that was involved in a merger during the sample period.[518] The differences between Staff's Proxy Group and Pepco's Proxy Group are two-fold: (1) Pepco's Proxy Group is restricted to

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[512] *Id.* at 5-6.
[513] *Id.* at 6-7.
[514] *Id.* at 8.
[515] McAuliffe Direct at 18.
[516] Staff Initial Brief at 22.
[517] McAuliffe Direct at 18.
[518] *Id.*

companies that pay a dividend and have not announced a dividend cut in six months; and (2) Pepco excludes companies with credit ratings one notch or more below Pepco's current credit rating.[519] Staff does not oppose Pepco's Proxy Group but notes that Staff's larger Proxy Group of 31 electric companies provides a larger data set for applying the ROE model and would, thus, generate more reliable ROE results.[520]

OPC

296. OPC witness Dr. Randall Woolridge identified a proxy group of 29 electric companies. He noted that his Electric Proxy Group utilities have median operating revenues and net plant of $7,523.1 million and $24,412 million, respectively. He explained further that on average, the Group receives 81 percent of its revenues from regulated electric operations; has BBB+/Baa1 issuer credit ratings from S&P and Moody's, respectively; has a current common equity ratio of 43.5 percent; and has an earned return on common equity of 10.5 percent.[521]

AOBA

297. Witness Oliver testified that for his ROE analysis, he used the same proxy group chosen by Pepco Witness McKenzie.[522] Mr. Oliver recognized that witness McKenzie's proxy group can serve as a starting point for assessing electric distribution utility ROE requirements.[523] He cautioned, however, that proxy groups dominated by utility holding companies—as seen in witness McKenzie's proxy group—can have an upward bias in ROE estimates insofar as holding company investment portfolios often include

[519] Staff Initial Brief at 23.
[520] *Id.* at 23.
[521] Woolridge Direct at 27.
[522] T. Oliver Direct at 20.
[523] *Id.* at 16.

significant non-utility and non-price regulated business activities.[524] Where "[i]t is widely understood that electric distribution utilities typically have lesser risk and lower equity return requirements than their parent companies," witness Oliver argued that reliance on Pepco's proxy group results, without a downward adjustment for the company's lesser-risk distribution service operations, would overstate Pepco's ROE requirements.[525]

2. <u>Economic Impacts of COVID-19</u>

<u>Pepco</u>

298. Witness McKenzie testified that "the threat posed by the coronavirus pandemic has led to extreme volatility in the capital markets as investors dramatically revise their risk perceptions and return requirements in the face of the severe disruptions to commerce and the world economy."[526] Pepco found that despite the actions of the world's central banks to ease market strains and bolster the economy, global financial markets have experienced extreme volatility and precipitous declines in asset values.[527] Witness McKenzie explained that while regulated utilities are generally "favorably positioned relative to other industry sectors," S&P has noted that "access to equity markets remains extraordinarily challenging."[528] Moreover, Pepco's perspective is that the pandemic has highlighted concerns regarding the credit quality of the utility industry, with S&P downgrading its industry outlook from "stable" to "negative" and utility betas increasing significantly following the pandemic.[529] Mr. McKenzie claimed that investors

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[524] *Id.* at 20.
[525] *Id.* at 16.
[526] McKenzie Direct at 11.
[527] *Id.* at 11-12.
[528] *Id.* at 16
[529] *Id.* at 15-16.

continue to face volatility in capital markets—compared to pre-pandemic levels—and greater exposure to uncertainty, and require higher, not lower, rates of return to induce long-term investment.[530] Witness McKenzie testified that "[w]hile there is continued hope for a relatively swift economic rebound as COVID-19 containment measures are gradually lifted, residual impacts of the unprecedented economic and health crisis could linger indefinitely."[531] Therefore, witness McKenzie argued that it would be imprudent to gamble the interests of customers and the Maryland economy in the hope that the harsh economic reality will be resolved suddenly.[532] Consequently, witness McKenzie stated that Pepco must raise capital in the real world of financial markets, and therefore ignoring that reality would be unwise.[533]

Staff

299. Witness McAuliffe testified that his ROE analysis considered the financial market effects attributed to COVID-19.[534] Witness McAuliffe stated that "the downturn in the market has created a lot of "noise" that makes it difficult to determine a company's ROE. The collapse in stock prices or selloff in March 2020 was historic by many measures and includes stock price information with disruptive price movements, which may not lend themselves to a traditional ROE evaluation."[535]

300. Notwithstanding market volatility, witness McAuliffe testified that the economic downturn from the pandemic caused the Federal Reserve to bolster the U.S. economy by

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[530] *See* McKenzie Direct at 16.
[531] McKenzie Direct at 19.
[532] *Id.*
[533] *Id.*
[534] McAuliffe Direct at 13.
[535] *Id.*

lowering borrowing rates and purchasing corporate bonds.[536] He explained, "These actions by the Federal Reserve have played an integral role in stabilizing the U.S. Treasury and corporate bond markets."[537] According to witness McAuliffe, "[t]he market downturn to date has been short lived … ."[538] Since March 2020, the three major market indices have each returned to all-time highs, with stock prices resembling those preceding the pandemic.[539] Despite witness McKenzie's belief that interest rates will rise over the course of the MRP, Mr. McAuliffe emphasized that interest rates recently reached all-time low levels and would likely remain low—well below any historical average—even if they increase over the MRP period.[540] "[This] would imply a lower cost of capital than was approved for Pepco in Case No. 9602."[541]

301. Witness McAuliffe noted that "one should also consider that certain risks for the utility business have increased because of COVID-19" and that those risks may not be known fully at this time.[542] He stated that while "[i]t may be intuitive to assume that utility sales would drop drastically because of COVID-19 lockdowns and other measures used to slow the spread of the disease, the data does not bear this out." In fact, many utilities have seen relatively flat changes in negative and positive demand. He said "[w]hile commercial and industrial demand has decreased, residential usage across the country has increased, which has offset, to some extent, the lower demands from large customers."[543]

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[536] *Id.* at 17.
[537] *Id.* at 18.
[538] *Id.* at 13.
[539] *See id.* at 13.
[540] *See id.* at 36.
[541] *Id.* at 36.
[542] *Id.* at 16.
[543] *Id.* at 16-17.

OPC

302. Witness Woolridge testified that the U.S. economy declined nearly 20 percent in the first half of 2020 but rebounded significantly in the second half of 2020, resulting in a 3.5 percent GDP decline for the year.[544] He also noted that "the U.S. unemployment rate peaked in the second quarter of 2020 at about 15 percent and is now back to 6.5 percent."[545] OPC noted that the stock market began recovering during the third week of March 2020. Despite the ongoing spread of COVID-19 and the economic crisis that followed, including record unemployment, the S&P 500 has recovered and is now back at record levels.[546] The 30-year Treasury yield, which dropped to record low levels below 1.0 percent, remains in the 2.0 percent range. And the markets' "fear index," the VIX, which represents market volatility expectations over a forward-looking 30-day period, has returned close to its long-time average of 20 after topping out over 50 in March 2020.[547]

AOBA

303. AOBA witness Timothy Oliver did not specifically address COVID-19-related economic impacts on ROE but generally testified that Pepco's requested ROE of 10.2 percent is overstated and fails to reflect current market conditions.[548] He observed that 30-year treasury rates have remained historically low over the last decade, due in large part to the Federal Reserve's monetary policies. According to witness Oliver, those policies, over which Pepco has no control, are expected to be maintained over the MRP

[544] Woolridge Direct at 23.
[545] *Id.* at 23.
[546] *Id.*
[547] *Id.*
[548] T. Oliver Direct at 5.

period.[549] He also commented that recent market conditions and sustained low interest rates, together with Pepco's legacy debt, will incrementally lower the Company's cost of long-term debt.[550]

3. <u>Parties' ROE Analyses</u>

304. To determine cost of equity, the Parties in this proceeding used various ROE models, including traditional and widely accepted approaches, such as the DCF and CAPM models, and newer and lesser used approaches, such as the Empirical Capital Asset Pricing Model ("ECAPM"), and the Utility Risk Premium ("RP") and Expected Earnings ("EE") models. Pepco witness McKenzie presented testimony on how he developed his recommended ROE range using all five of these methodologies. By contrast, Staff based its ROE recommendation on the DCF, CAPM, and RP methods, while OPC and AOBA both used only the DCF and CAPM models. This section provides an overview of the various Parties' analyses under each approach.

4. <u>Discounted Cash Flow</u>

<u>*Pepco*</u>

305. Witness McKenzie testified that "[t]he DCF method, which is frequently referenced and relied on by regulators, is only one theoretical approach to gain insight into the return investors require; there are numerous other methodologies for estimating the cost of capital and the ranges produced by the different approaches can vary widely."[551] No single method can be regarded as failsafe; all approaches have advantages

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549 *Id.* at 24.
550 *Id.*
551 McKenzie Direct at 21.

and disadvantages.[552] He pointed out that FERC has noted, "[t]he determination of rate of return on equity starts from the premise that there is no single approach or methodology for determining the correct rate of return."[553] He also stated that while the DCF model is a recognized approach to estimating the ROE and ultimately the one he uses to base his ROE recommendations, it is not without shortcomings and does not otherwise eliminate the need to ensure that the "end result" is fair.[554]

306. Pepco witness McKenzie testified that the DCF model assumes the price of a share of common stock is equal to the present value of the expected future cash flows (dividends and stock price) that will be received while holding the stock, discounted at the investor's required rate of return.[555] He further testified that the DCF model can be simplified to an equation reflecting "constant growth," where the cost of equity is equal to the ratio of the expected dividend per share in the coming year and the current price per share (called the dividend yield) plus the investor's long-term growth expectations.[556]

307. Witness McKenzie explained that applying the constant growth DCF model required three steps. The first step was to determine the expected dividend yield for the firm in question.[557] This is usually calculated based on an estimate of dividends to be paid in the coming year, divided by the current price of the stock.[558] The second, more controversial step is to estimate investors' long-term growth expectations for the firm. The final step is to add the firm's dividend yield and estimated growth rate to arrive at an

[552] *Id.*
[553] *Id.*
[554] *Id.* at 22.
[555] *Id.* at 24.
[556] *Id.* at 25.
[557] *Id.*
[558] *Id.*

estimate of its cost of common equity.[559] Witness McKenzie used Value Line estimates of the dividends to be paid by each of the utilities in the proxy group over the next 12 months.[560] This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield.[561] The dividend yields for the utilities in Witness McKenzie's proxy group ranged from 2.3 percent to 6.4 percent, with an average of 3.8 percent.[562] When determining the long-term growth expectations, witness McKenzie indicated that there are many techniques that can be used to derive long-term growth rates. But when applying the DCF model, the only long-term growth expectation that matters is the value that investors expect.[563] Witness McKenzie testified that he relied on projected growth rates for the proxy groups published by Value Line, IBES, and Zacks, and that he calculated projected "sustainable growth rates" for the proxy companies.[564]

308. Witness McKenzie testified that in evaluating the results of the constant growth DCF model, it is essential that resulting values pass fundamental tests of reasonableness and economic logic. "Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method."[565] He noted that FERC agrees that adjustments are justified where applications of the DCF approach produce illogical results.[566]

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[559] *Id.*
[560] *Id.*
[561] *Id.*
[562] *Id.*
[563] *Id.* at 26.
[564] *Id.* at 31.
[565] *Id.* at 32.
[566] *Id.*

309. Based on these assumptions, Mr. McKenzie projected a range of ROEs with averages between 8.4 and 9.1 and midpoints ranging between 8.6 and 10.2.[567]

Staff

310. Staff witness McAuliffe also performed a DCF analysis, which resulted in an average DCF ROE of 8.89.[568] Mr. McAuliffe excluded from his analysis companies that had ROEs either below 6.5 or above 14.[569] He explained that the data for his model was collected from Value Line and Yahoo Finance. He used the dividends paid by each proxy group member over the last year during the period including February 1, 2020 to January 31, 2021, and the average stock prices of the proxy group members over the last 180 days from August 4, 2020 to January 29, 2021, which were collected from Yahoo Finance.[570] He used a 180-day period to balance the effect of short-term volatility on stock prices and the use of outdated data.[571] Using Value Line reports for the most recent quarter, he projected three to five year dividend growth, and the projected three to five year earnings per share were collected from VL reports for the most recent quarter.[572]

OPC

311. OPC witness Woolridge performed a DCF analysis on his Electric Proxy Group and the McKenzie Proxy Group.[573] Dr. Woolridge testified that "[t]he economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF."[574] However, witness Woolridge contended that "the primary

[567] *Id.* at 36.
[568] McAuliffe Direct at 21-22.
[569] *Id.* at 22.
[570] *Id.* at 21.
[571] *Id.*
[572] *Id.*
[573] Woolridge Direct at 4.
[574] *Id.* at 38.

problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate."[575] Additionally, he noted that when using the DCF model, one must be sensitive to estimating the dividend yield and the expected growth rate.[576] He pointed out that the dividend yield can be measured precisely at any point in time, but it tends to vary over time. However, estimating expected growth is considerably more difficult, and consideration should be given to recent firm performance in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.[577]

312. For his Electric Proxy Group, Dr. Woolridge testified that the mean and median dividend yields using the 30-day, 90-day, and 180-day average stock prices ranged from 3.8 to 3.9.[578] Hence, he used 3.85 as the dividend yield for his Electric Proxy Group. Performing the same analysis for the McKenzie Proxy Group, witness Woolridge noted that the mean and median dividend yields ranged from 3.6 to 3.8 percent using the 30-day and 90-day average stock prices. Given this range, he chose to use 3.7 percent as the dividend yield for the McKenzie Proxy Group.[579]

313. Dr. Woolridge also performed the expected growth rate analysis for companies in the proxy groups. He indicated that he "reviewed Value Line's historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS")."[580] Additionally, he utilized the average EPS growth

[575] *Id.* at 39.
[576] *Id.*
[577] *Id.*
[578] *Id.* at 38-39.
[579] *Id.* at 40.
[580] *Id.* at 41.

rate forecasts of Wall Street analysts as provided by Yahoo and Zacks.[581] According to Witness Woolridge, there is upward bias in analysts' long-term EPS growth rate forecasts, and stock prices reflect the bias.[582] He therefore believes that the DCF growth rate must be adjusted downward from the projected EPS growth rate to reflect the upward bias in the DCF model.[583]

314. Based on dividend yield and the expected growth rate, witness Woolridge's DCF analysis resulted in an ROE range between 8.95 percent and 9.05 percent (see Table 6 below).

Table 6[584] DCF-Derived Equity Cost Rate/ROE				
Proxy Group	**Dividend Yield**	**1 + ½ Growth Adjustment**	**Growth Rate**	**Equity Cost Rate**
Electric Proxy Group	3.85%	1.0250	5.00%	8.95%
McKenzie Proxy Group	3.70%	1.02625	5.25%	9.05%

315. Witness Woolridge raised the following "primary issues" with Mr. McKenzie's DCF analysis: (1) his asymmetric elimination of low-end DCF results; and (2) the excessive use of the overly optimistic and upwardly biased EPS growth rate forecasts of Wall Street analysts as the growth rate in his DCF model."[585]

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[581] *Id.*
[582] *Id.* at 48.
[583] *Id.*
[584] *Id.* at 51 based on Table 4 in witness Woolridge's Direct Testimony.
[585] *Id.* at 73.

316. Dr. Woolridge explained that "[b]y eliminating low-end outliers while keeping the same number of high-end outliers, Mr. McKenzie biases his DCF equity cost rate study and reports a higher DCF equity cost rate than the data indicate."[586] He testified that his DCF analysis avoids this error by "us[ing] the median as a measure of central tendency so as to not give outlier results too much weight. This approach also avoids biasing the results by including all data in the analysis and not selectively eliminating outcomes."[587]

317. Second, witness Woolridge stated that by exclusively relying on the projected growth rates of Wall Street analysts and Value Line, witness McKenzie improperly inflated his growth rate estimates.[588] Witness Woolridge argued that "the appropriate growth rate in the DCF model is the dividend growth rate rather than the earnings growth rate. Hence, consideration must be given to other indicators of growth, including historical prospective dividend growth, internal growth, as well as projected earnings growth."[589]

AOBA

318. AOBA witness Timothy Oliver performed a DCF analysis to determine an appropriate ROE. Witness Oliver "used the same proxy group chosen by Witness McKenzie, noting the inherent upward bias in ROE estimates that a proxy group dominated by utility holding companies can be expected to yield for an electric distribution utility such as Pepco."[590] Witness Oliver used annual high and low stock

[586] *Id.* at 74.
[587] *Id.* at 74.
[588] *Id.* at 75.
[589] *Id.* at 75.
[590] T. Oliver Direct at 20.

price data and earnings growth projections from Zacks, CNN, and Yahoo in a traditional Constant Growth DCF model.[591] Witness Oliver stated that due to a lack of an explicit adjustment to account for the reduced risk of a distribution utility compared to a holding company, the results of the DCF analysis should be viewed as an upper bound for an appropriate ROE for a distribution utility such as Pepco.[592] Witness Oliver testified that the average ROE based on his DCF analysis is 8.58%.[593]

5. <u>CAPM</u>

<u>Pepco</u>

319. Pepco witness McKenzie testified that the CAPM "is a theory of market equilibrium that measures risk using a 'beta' coefficient," which measures the tendency of a stock's price to follow changes in the market.[594] He clarified that a stock that tends to respond less to market movements has a beta less than 1.0, while stocks that tend to move more than the markets have betas greater than 1.0.[595] Like the DCF Model, witness McKenzie testified that CAPM is a forward-looking model based on expectations of the future.[596] Additionally, Mr. McKenzie testified that the CAPM is the most widely referenced method among both academicians and professionals for estimating the cost of equity, and thus provides important insight into investors' required rate of return.[597] Under the CAPM, the required rate of return is equal to the risk-free rate of return (such as Treasury bonds) plus the product of the stock's beta and the difference between the

[591] *Id.* at 21.
[592] *Id.*
[593] Id at 22.
[594] McKenzie Direct at 36.
[595] *Id*. at 36-37.
[596] *Id.* at 37.
[597] *Id.*

expected return on the market portfolio and the risk-free rate.[598] Mr. McKenzie also testified that financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size.[599] Therefore, a modification is required to account for the size effect.[600] Witness McKenzie testified that his CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the Electric Group.[601] After adjusting for the impact of firm size, witness McKenzie's CAPM analysis yields an average ROE for the Electric Group of 10.4 percent.[602] Further, witness McKenzie applied the CAPM using forecasted bond yields. He explained that there is general consensus that interest rates will increase over the effective period of the rates established in this proceeding.[603] Therefore, in addition to the use of current bond yields, he applied the CAPM based on forecasted long-term Treasury bond yields developed using projections published by Value Line, IHS Global Insight, and Blue Chip for the years 2021-2025. As a result of incorporating a forecasted Treasury bond yield, witness McKenzie assessed an average cost of equity estimate of 10.5 percent for the Electric Group.[604]

320. Mr. McKenzie also presented testimony on a modified version of the CAPM, called the Empirical CAPM or ECAPM.[605] He testified that empirical tests of the CAPM have shown that low-beta securities earn somewhat higher returns than the standard

[598] *Id.*
[599] *Id.* at 38.
[600] *Id.*
[601] *Id.* at 39.
[602] *Id.*
[603] *Id.* at 40.
[604] *Id.*
[605] *Id.*

CAPM would predict, while high-beta securities earn less than predicted.[606] For utility stocks, which tend to have betas less than 1.0, this implies that CAPM tends to understate the cost of equity.[607]

321. Like the CAPM formula, witness McKenzie explained that the ECAPM represents a stock's required return as a function of the risk-free rate, plus a risk premium.[608] This risk premium is composed of two parts: (1) the market risk premium, weighted by a factor of 25 percent; and (2) a company-specific risk premium based on the stock's relative volatility, weighted by 75 percent.[609] Thus ECAPM, with its associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research; it also corrects for the understated returns that would otherwise be produced for low-beta stocks.[610] Witness McKenzie noted that Commission Staff has relied on the ECAPM approach in the past, in Case No. 9299, a 2012 BGE rate case.

322. Witness McKenzie explained further that his applications of the ECAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values used with his CAPM analysis.[611] He applied the forward-looking ECAPM approach to the firms in his Electric Group, which yielded an average cost of equity estimate of 10.7 percent, after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.[612] When he applied the ECAPM using a forecasted Treasury

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[606] *Id.*
[607] *Id.* at 41.
[608] *Id.*
[609] *Id.* at 42.
[610] *Id.*
[611] *Id.* at 43.
[612] *Id.* at 44.

bond yield for 2021-2025, his average cost of equity estimate for the Electric Group increased slightly to 10.8 percent.[613]

Staff

323. Staff witness McAuliffe also performed a CAPM analysis. He testified that the inputs for his model came from various sources. He described his inputs as follows:

> The Rf risk free rate is calculated using the average of the 30-year Treasury bond yields during the period from January 30, 2020 until January 29, 2021; the Beta β values are obtained from [Value Line]. The market return Rm is based on the 1926 to 2019 arithmetic mean for large-cap stocks. The [equity risk premium ("ERP")] is the market return minus the risk-free rate; this value is multiplied by the beta to determine the ROE for each company.[614]

324. Mr. McAuliffe excluded any ROE result outside of the 6.5 percent to 14 percent band. Then he averaged the remaining results, producing a final result of 9.45 percent.[615]

325. Witness McAuliffe testified that the CAPM model seems to be the most impacted by the recent economic downturn caused by COVID-19.[616] He discussed how beta values have increased from levels prior to the market downturn in March 2020. For instance, the average beta for the proxy group in the quarter prior to the downturn was 0.54 and is now 0.87.[617] Further, his testimony highlighted the drastic changes that market conditions can have on betas and the resulting ROE. Specifically, he testified that "using the betas from prior to the market downturn would result in an ROE of 7.52 percent. Using betas from the current quarter results in an ROE of 10.77."[618]

[613] *Id.*
[614] McAuliffe Direct at 22.
[615] *Id.*.
[616] *Id.*
[617] *Id.* at 23.
[618] *Id.*

OPC

326. OPC witness Woolridge also performed a CAPM analysis.[619] Dr. Woolridge selected a risk-free rate of 2.5 percent[620] based on historical 30-year Treasury yields. Witness Woolridge stated that he would continue to use Value Line betas in his CAPM as a conservative approach.[621] However, Dr. Woolridge pointed out several issues with the Value Line betas.[622] He reviewed market risk premium studies from January 2, 2010 to present, which suggest that the appropriate market risk premium in the U.S. is in the range of 4 percent to 6 percent.[623] He selected 6 percent and described it as a "conservatively high estimate" of the market risk premium considering the many studies and surveys of the market risk premium.[624] Based on his CAPM analysis, witness Woolridge calculated CAPM ROEs of 7.6 percent for his Electric Proxy Group and 7.9 percent for the McKenzie Proxy Group.[625]

327. Regarding CAPM/ECAPM, witness Woolridge testified that the primary errors with Mr. McKenzie's ECAPM analysis are: (1) the use of the ECAPM itself; (2) the expected market return of 11.3 percent used to compute the market risk premiums; and (3) the company size adjustment.[626]

AOBA

328. AOBA witness Oliver also performed a CAPM analysis to determine the appropriate ROE. For his analysis, witness Oliver used the same proxy group chosen by

[619] Woolridge Direct at 53.
[620] *Id.* at 54.
[621] *Id.* at 58.
[622] *Id.* at 56-58.
[623] *Id.* at 66.
[624] *Id.* at 67.
[625] *Id.*
[626] *Id.* at 77.

witness McKenzie.[627] Due to the current environment of extremely low 30-year Treasury rates, witness Oliver elected to use both the 2020 average rate and a current rate as of February 5, 2021.[628] The average 2020 30-year Treasury rate is 1.56 percent; the current 30-year Treasury rate as of February 5, 2021 is 1.97 percent.[629]

329. Witness Oliver noted that his CAPM analysis takes into account the lack of market data on which to base an assessment of differences in risk and return requirements between Pepco and the proxy group and/or between Pepco and the general market.[630] In the absence of publicly traded Pepco stock, the differences in risk associated with stock price volatility are unobservable. Mr. Oliver pointed out that Pepco witness McKenzie's attempt to avoid addressing this problem by assuming that the risk of his proxy group companies—as measured through the use of beta coefficients—provides an appropriate differentiation of Pepco's risk from the general market. According to witness Oliver, however, proxy group risk is not the same as Pepco's risk.[631] Witness Oliver approaches the issue differently by recognizing that appropriate beta coefficients and/or other market-based measures of risk cannot be computed for a company that does not have publicly traded stock.[632] Instead, witness Oliver accounted for such risk differentials through adjustments to the assumed risk premiums.[633] Mr. Oliver calculated an average CAPM result of 8.94 percent.

[627] T. Oliver Direct at 20.
[628] *Id.* at 21.
[629] *Id.*
[630] *Id.* at 22.
[631] *Id.*
[632] *Id.*
[633] *Id.*

6. <u>Utility Risk Premium</u>

Pepco

330. Witness McKenzie also presented testimony on the Utility Risk Premium approach for determining ROE. He described the Risk Premium method as extending the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks.[634] Under the Risk Premium method, "[t]he cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds."[635] Mr. McKenzie testified that the Risk Premium approach is based on the fundamental risk-return principle which holds that investors will require a premium in the form of a higher return in order to assume additional risk.[636] He further testified that this is accomplished via surveys of previously authorized ROEs, which are presumed to reflect regulatory commissions' best estimates of the cost of equity.[637] Mr. McKenzie relied on data published by S&P Global Market Intelligence.[638]

331. Witness McKenzie also noted that the magnitude of equity risk premiums, or ERPs, is not constant, and ERPs tend to move inversely with interest rates. "In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in

[634] McKenzie Direct at 44.
[635] *Id.*
[636] *Id.*
[637] *Id.* at 45.
[638] *Id.*

lockstep with, interest rates."[639] Mr. McKenzie testified that using regression analysis, "the equity risk premium for electric utilities increases by approximately 43 basis points for each percentage point drop in the [average] yield on ... public utility bonds."[640] He noted that "with an average yield on public utility bonds for the six months ending June 2020 of 3.33 [percent], this implies a current equity risk premium of 5.85 [percent] for electric utilities. Adding this equity risk premium to the average yield on Baa utility bonds implies a current ROE of 9.57 [percent]."[641] After incorporating a forecasted bond yield for 2021-2025 and adjusting for changes in interest rates since the study period, witness McKenzie calculated an ERP of 5.51 percent for electric utilities, which is less than current ERPs.[642] He stated that lower ERPs are consistent with their inverse relationship with interest rates.[643] Therefore, "adding this [ERP] to the implied average yield on Baa public utility bonds for 2021-2025 of 4.82 percent results in an implied cost of equity of 10.33 percent."[644]

Staff

332. Staff Witness McAuliffe also performed a Utility Risk Premium Analysis using Pepco's current cost of long-term debt of 4.82 percent because the rates for long-term debt will most likely be below this level through at least year 2022.[645] He then added an ERP to the long-term debt to derive the ROE. To calculate the ERP, Mr. McAuliffe relied upon an average of two methodologies: a Public Utility Index Approach to estimate a utility-specific ERP, and the estimates of the ERP from various financial and

[639] *Id.* at 46.
[640] *Id.* at 47.
[641] *Id.*
[642] *Id.*
[643] *Id.* at 47-48.
[644] *Id.* at 48.
[645] Witness McAuliffe Direct at 26.

industry experts.[646] The average ERP from these studies "is 5.11 percent, which [is] then averaged with the ERP of 4.62 percent based on the difference between the returns for the S&P 500 utilities index and the yield of A rated utility bonds. This results in an ERP of 4.87 percent, which is then added to Pepco's cost of long-term debt of 4.82 percent, which results in a ROE of 9.69 percent."[647]

OPC

333. OPC witness Woolridge did not perform a Utility Risk Premium Analysis for ROE. However, witness Woolridge did offer certain criticisms of Mr. McKenzie's Utility Risk Premium Analysis. Specifically, he testified that the major issue is that "Mr. McKenzie's risk premium is not necessarily applicable to measure utility investors' required rate of return."[648] Witness Woolridge observed that the Utility Risk Premium approach focuses on gauging commission behavior, not investor behavior.[649]

AOBA

334. AOBA witness Oliver did not perform a Utility Risk Premium analysis to determine ROE.

7. Expected Earnings

Pepco

335. Witness McKenzie also presented testimony on the Expected Earnings ("EE") method. He testified that the EE approach is consistent with the economic underpinnings for a just and reasonable rate of return established by the U.S. Supreme Court in *Bluefield*

[646] *Id.* at 26.
[647] *Id.* at 27.
[648] Woolridge Direct at 98.
[649] *Id.*

and *Hope*.[650] He also stated that EE avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.[651] He asserted that "[t]he simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity."[652]

336. Witness McKenzie testified that the EE test involves identifying a group of companies of comparable risk to the utility and then comparing the actual earnings of those companies on the book value of their investment to the allowed return of the utility.[653] Mr. McKenzie applied this method to data from Value Line to reach an average ROE of 11 percent for the Electric Group.[654]

Staff

337. Witness McAuliffe did not perform an EE analysis for the ROE.

OPC

338. OPC witness Woolridge did not perform an EE analysis for ROE. However, Dr. Woolridge testified about several issues with this approach and strongly suggested that the Commission ignore this approach in setting an ROE for Pepco.[655] Those issues include:

1. The EE approach does not measure the market cost of equity capital;[656]

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[650] McKenzie Direct at 48 *citing Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[651] McKenzie Direct at 48.
[652] *Id.*
[653] *Id.* at 49.
[654] *Id.* at 50.
[655] Woolridge Direct at 99.
[656] *Id.* at 100.

2. The expected ROEs are not related to investors' market-priced opportunities;[657]

3. Changes in ROE ratios do not track capital market conditions;[658]

4. The EE approach is circular;[659] and

5. The proxies' ROEs reflect earnings on business activities that are not representative of PEPCO's rate-regulated utility activities.[660]

339. OPC witness Woolridge testified that "in short, Mr. McKenzie's Expected Earnings approach does not measure the market cost of equity capital, is independent of most cost of capital indicators and, as shown above, has a number of other empirical issues. Therefore, the Commission should ignore this approach in determining the appropriate ROE for PEPCO."[661]

AOBA

340. AOBA witness Oliver did not perform an EE analysis to determine ROE.

8. Parties' Final ROE Recommendations

Pepco

341. Pepco witness McKenzie testified that considering the Company's need to support continuous access to capital under reasonable terms and the results of his analyses, he recommends a 10.2 percent ROE for Pepco's electric utility operations.[662] His recommendation is supported by his DCF, CAPM, ECAPM, risk premium, and EE analyses to a proxy group of electric utilities, which yielded a cost of equity range of 9.5

[657] *Id.*
[658] *Id.* at 101.
[659] *Id.*
[660] *Id.*
[661] *Id.*
[662] McKenzie Direct at 58.

percent to 10.8 percent.[663] He concluded that the 10.2 percent midpoint of this range represents a just and reasonable cost of equity that is adequate to compensate the Company's investors, while maintaining the Company's financial integrity and ability to attract capital on reasonable terms.[664]

342. Staff witness McAuliffe argued that his primary concern with witness McKenzie's final ROE recommendation of 10.2 percent is that it is much higher than the nationwide average. The nationwide average of authorized ROEs was 9.44 percent in 2020 for electric utilities, including vertically integrated companies and single-issue rider cases.[665] Mr. McAuliffe noted the 2020 nationwide average "is the lowest level for any year on record."[666]

343. Staff witness McAuliffe summarized the results of McKenzie's ROE models in Table 7 below. Staff witness McAuliffe did not take issue with Pepco's use of averages to determine the company's ROE range, but he expressed concern with Mr. McKenzie's use of "midpoints," contending that the use of the midpoint to establish the ROE range skews the results in Pepco's case.[667] Specifically, witness McAuliffe pointed out that witness McKenzie's ROE midpoint is not the median; it is the average of the highest value in the data set and the lowest value in the data set after outliers are removed.[668] Staff witness McAuliffe's "core concern is that the midpoint relies on only two values, the highest and lowest value in the data set. The midpoint is not necessarily representative of all of the

[663] *Id.* at 3.
[664] *Id.*
[665] McAuliffe Direct at 32.
[666] *Id.*
[667] *Id.* at 30. For instance, Witness McAuliffe noted that "The DCF results of Witness McKenzie when using the averages, 9.1, 8.8, 9.0 and 8.4 percent are similar to my DCF result of 8.89 for the electric proxy group." *See id.* at 39.
[668] McAuliffe Direct at 31.

values in the data set. What exacerbates this concern is that Witness McKenzie selects the range of results he deems are appropriate, which allows him to determine what the midpoint value will be."[669]

Table 7[670] Pepco ROE Results and Recommendation		
Electric Group	**Average**	**Midpoint**
DCF		
ValueLine	9.1%	10.2%
IBES	8.8%	8.6%
Zacks	9.0%	8.7%
Br+sv	8.4%	9.1%
CAPM		
Current Yield	10.4%	10.6%
Projected Yield	10.5%	
ECAPM		
Current Yield	10.7%	10.8%
Projected Yield	10.8%	10.9%
Risk Premium		
Current Yield	10.3%	
Projected Yield	9.6%	
Expected Earnings	11.0%	11.2%
Recommended Range	**9.5%**	**10.8** %
Final ROE	**10.2%**	

Staff

344. Staff witness Drew McAuliffe testified that his final ROE recommendation of 9.4 percent "was determined based on the Commission's precedent for gradual decreases or

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[669] *Id.*
[670] *Id.* at 30, Table 4.

increases in ROE."[671] He testified that his results ranged from 8.89 percent to 9.69 percent.

Table 8[672] Summary of Staff ROE Analysis				
ROE Results				
	DCF	**CAPM**	**RP**	**Average**
	8.89%	9.45 %	9.69%	9.34 %
Recommendation	**9.4%**			

345. Based upon the results of his DCF, CAPM and RP analysis, the market's effect on ROE analyses, and the Commission's previous reliance on gradualism, witness McAuliffe recommends an ROE of 9.4 percent—a reduction of 20 basis points from Pepco's currently authorized ROE of 9.6 percent to allow for gradual changes.[673] He pointed out that there is Commission precedent to take gradualism into consideration. Specifically, witness McAuliffe cited Commission Order No. 87884 in explaining how gradualism provides stability and certainty to the benefit of both ratepayers and investors.

> We agree that current market conditions favor a cost of equity that is lower than Pepco's currently approved ROE of 9.62%. But how much lower? Historically, we have generally followed the principle of gradualism when implementing major rate design changes that have a potentially adverse impact on a particular class of customers. Gradualism prescribes that sudden and dramatic shifts in rate design should be avoided. We find that gradualism works both ways and would be appropriate in this instance to lessen the impact on the company and

[671] *Id.* at 27.
[672] *Id.* at 15.
[673] *Id.* at 27.

> investors. Relative stability in rates is an important ratemaking goal—for ratepayers and utilities alike. As Mr. VanderHeyden explained regarding returns on equity, "[o]ne of the properties of our rate making process is that awarded ROEs do not instantly respond to market changes. Awarded ROEs should make gradual movements." Implementing gradual movement will "encourage an environment that does not surprise investors with changes that impact them adversely."[674]

346. Additionally, witness McAuliffe stated that "[i]n determining an appropriate ROE in connection with a multi-year rate plan, the Commission has also considered the reduction of regulatory lag due to the nature of a multi-year rate plan."[675] In Case No. 9645, the Commission addressed BGE's multi-year rate plan and noted that "[t]he approved ROEs appropriately account for reduced regulatory lag and risk arising from BGE's decision to request multi-year rates, which will remain fixed over a three-year rate-effective period."[676] Witness McAuliffe testified that his recommendation of 9.4 percent properly balances current market conditions and the Commission's previous reliance on gradualism and the reduction in regulatory lag due to a multi-year rate plan.[677]

OPC

347. Dr. Woolridge testified that his analysis indicates that a 9.0 percent return on equity is appropriate for Pepco's electric utility distribution operations.[678] He stated that his recommendation is at the high end of the equity cost range of 7.3 percent to 9.05 percent, which comprises the results of his ROE analyses.[679] Given his recommended capitalization ratios, senior capital cost rates, and the 9.0 percent ROE, his overall rate of return or cost of capital recommendation for the Company is 6.93 percent.

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[674] *Id.*
[675] *Id.* at 28.
[676] *Id.*, *citing* Order No.89678 at 154.
[677] McAuliffe Direct at 28.
[678] Woolridge Direct at 4-5.
[679] *Id.* at 5.

AOBA

348. AOBA witness Oliver testified that although his DCF and CAPM analyses clearly support a downward adjustment to Pepco's currently authorized ROE of 9.6, he remains sensitive to the Commission's policy of applying gradualism in the adjustment of a utility's ROE.[680] To reflect this gradualism policy, witness Oliver initially applied a 10-basis point reduction to the Company's currently authorized ROE, bringing the ROE to 9.5. He reasoned that "[t]he Commission's precedent of 5 basis points per year being a gradual adjustment is applied for the roughly two-year period between Case No. 9602 and the rate effective date of this proceeding."[681]

349. In addition to gradualism, Mr. Oliver proposes to apply a 25-basis point MRP Risk Reduction adjustment.[682] He argued that this MRP Risk Reduction adjustment is supported by Commission precedent. In Case No. 9092, the Commission implemented a similar adjustment upon the inception of Pepco's Bill Stabilization Adjustment ("BSA") mechanism to reflect the reduced risk a decoupling mechanism has on its ability to achieve its level of approved revenue.[683] Witness Oliver argues that "Pepco's proposed MRP in a likewise manner eliminates even greater risk than the BSA did in its inception due to a combination of monthly BSA adjustments and annual reconciliations."[684]

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[680] T. Oliver Direct at 23.
[681] *Id.*
[682] *Id.*
[683] *Id.*, *citing* Case No. 9092, Order No. 81408 at 72.
[684] T. Oliver Direct at 23.

9. Capital Structure and Cost of Debt

Pepco

350. Pepco witness Elizabeth O'Donnell presented testimony setting forth the appropriate capital structure to be used during the Pepco's MRP period. Ms. O'Donnell testified that as of March 31, 2020, the Company's capital structure ratio consisted of 50.5 percent common equity and 49.5 percent long-term debt (with an embedded long-term debt cost of 4.82 percent).[685] She explained that "the pro forma capital structure reflects Pepco's $150 million 30-year long-term debt bond issuance that was priced and closed on February 12, 2020, and funded on September 23, 2020."[686] Additionally, the proposed 50.5 percent equity ratio is consistent with the actual March 30, 2020 capital structure, which was 50.66 percent[687] and further "consistent with the Company's goals and objectives to maintain the Company's current credit ratings and a target equity ratio of at least 50 percent."[688]

351. Witness O'Donnell provides several other reasons why Pepco's proposed capital structure should be adopted, including: (1) the capital structure has been calculated in the same manner and accepted by the Commission in previous rate cases including the most recent Pepco rate case, Case No. 9602[689]; (2) the mean common equity ratio is 52.2 percent of the electric operating subsidies of the 23 companies in Company witness McKenzie's proxy group for the purpose of determining the cost of equity for this proceeding[690]; and (3) the Company's current credit ratings are based on its commitment

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[685] O'Donnell Direct at 2.
[686] *Id.*
[687] *Id.* at 3.
[688] *Id.*
[689] *Id.*
[690] *Id.*

to the Rating Agencies to maintain a minimum capital structure consistent with these percentages.[691]

Staff

352. Staff witness McAuliffe proposed a capital structure of 50.5 percent common equity and 49.5 percent long-term debt as proposed by Pepco Witness O'Donnell.[692] Witness McAuliffe also pointed out that the proposed capital structure was "similar to Pepco's test year actuals of 50.66 percent equity and 49.34 percent long term debt."[693] He also noted that the proposed capital structure is also similar to national trends and that the average authorized equity ratio for electric utilities in the U.S. in 2020 was 49.69 percent.[694]

353. Additionally, Staff witness McAuliffe found Pepco's embedded cost of debt of 4.82 percent to be reasonable and appropriate. Mr. McAuliffe pointed out that in response to a Staff data request, Pepco said that it "plans to reflect its actual cost of debt in the annual information filing, consolidated reconciliation, and final reconciliation filings."[695] While Pepco has not proposed to adjust its cost of debt during the MRP period as BGE suggested in its MRP in Case No. 9645, witness McAuliffe recommended that the Commission adopt the same position here and reject any adjustments to Pepco's cost of debt of 4.82 percent during the MRP period.[696]

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[691] *Id.*
[692] McAuliffe Direct at 20.
[693] *Id.*
[694] *Id.*
[695] *Id.* at 21.
[696] *Id.*

OPC

354. OPC witness Woolridge testified that "although Pepco has proposed a capital structure that includes more equity capital and less financial leverage than the capital structures of other electric utility companies, he did not believe it was unreasonable."[697] Witness Woolridge adopted Pepco's proposed capital structure, senior capital cost rates and Pepco's proposed long-term debt rate of 4.82 percent.[698] However, Dr. Woolridge cautioned the Commission that when setting the return on equity, it should recognize that Pepco's proposed capital structure includes a common equity ratio that is larger than those of other utility companies.[699]

AOBA

355. AOBA witness Oliver agreed that Pepco's proposed capital structure is reasonable and addresses each of the four considerations that he suggested the Commission must balance in determining the appropriate capital structure for ratemaking purposes.[700] The four questions of consideration that the Commission must balance are:

1. Does the proposal reflect a reasonable attempt to minimize the overall costs to ratepayers of financing the Company's utility operations?

2. Does the proposal support the financial stability and health of the Company's utility operations?

3. Does the proposal inappropriately foster subsidization of the activities of non-regulated affiliates?

4. Does the proposal provide the Company substantial opportunities to improve its profitability by utilizing an actual capital structure that differs from the capital structure approved for ratemaking purposes?[701]

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[697] OPC Initial Brief at 27.
[698] *Id.*
[699] *Id.* at 28.
[700] T. Oliver Direct at 13.
[701] *Id.* at 12.

356. Mr. Oliver presented an analysis illustrating that Pepco's cost of long-term debt has steadily declined since 2012.[702] He explained that this decline has two primary drivers: (1) the macroeconomic conditions over the last decade reflect consistent, historically low 30-year Treasury rates, which will likely continue over the MRP period; and (2) Pepco's pre-2008 debt issuances were more expensive, including its largest issuance of $250 million in 2008.[703] Witness Oliver assessed that the downward trend in Pepco's cost of long-term debt reflects a 17-basis point per year reduction, which he argued is a substantive annual change in both the Company's weighted costs of debt and its overall rate of return requirements. Therefore, witness Oliver opposed approval of a fixed cost of long-term debt based on the Company's embedded long-term debt cost.[704]

357. In its brief, AOBA argued that "[w]hile it may be reasonable for the Commission to set the Company's capital structure and ROE for the duration of the [MRP], the cost of long-term debt should continue to reflect market-based cost considerations. A failure to do so, would only serve to enhance the Company's ability to augment its effective equity returns while providing no identifiable benefit for Pepco's Maryland ratepayers."[705] AOBA suggested that a less market-based approach could have the Commission set a fixed cost of long-term debt on the average of AOBA's projected long-term debt costs for Pepco for the three years of the MRP, which would be a fixed 4.38 percent average long-

[702] *Id.* at 24.
[703] *Id.*
[704] AOBA Initial Brief at 21.
[705] *Id.* at 23.

term cost of debt for the MRP period or reduction of 44 basis points from Pepco's requested 4.82 percent cost of long-term debt.[706]

358. In rebuttal, Pepco witness McKenzie refuted AOBA witness Oliver's assessment of the continued downward trend of Pepco's cost of long-term debt. Specifically, he noted that AOBA's position "contradicts the expectations of widely recognized forecasting services, which uniformly anticipate that bond yields will increase over the intermediate term."[707] Moreover, witness McKenzie pointed out that "recent trends in the credit markets also disprove AOBA witness Oliver's idea that bond yields will decline in a linear fashion over the [MRP] period."[708] Lastly, witness McKenzie testified that AOBA witness Oliver's recommendation is derived "by performing a linear regression using the cost of long-term debt supported in Pepco's prior base rate proceedings since 2012."[709] Witness McKenzie argued that the "notion that the future course of debt maturities and interest rates can be estimated based on a mere extrapolation of recent trends is simplistic and highly suspect."[710]

Commission Decision

359. In determining a utility's appropriate rate of return, the Commission adheres to the general principles established in the U.S. Supreme Court's *Bluefield*[711] and *Hope Natural Gas*[712] decisions. Stated succinctly, the *Bluefield* and *Hope* cases require returns that are sufficient to attract capital on reasonable terms, maintain the utility's financial

[706] *Id*. at 24.
[707] McKenzie Rebuttal at 91.
[708] *Id.* at 92.
[709] *Id.* at 93.
[710] *Id.*
[711] *Bluefield Waterworks and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923).
[712] *Federal Power Comm'n v. Hope Natural Gas Co.* (*"Hope"*), 320 U.S. 591, 603 (1944).

integrity, and provide investors with the opportunity to earn a return comparable to investments carrying similar risks.[713]

360. The Commission must ensure that a public utility charges just and reasonable rates for the regulated services that it provides.[714] Pursuant to well-established regulatory principles, regulated utilities are allowed the opportunity to recover the costs of prudently incurred debt financing and to earn a return on equity financing.

361. In a proceeding involving a change in rates, the burden of proof is on the proponent of the change. Thus, in the instant matter, Pepco bears the burden to support every element of its request for a rate increase. As testified to by all parties, long-standing Supreme Court precedent, primarily *Bluefield* and *Hope*, established a standard by which the Commission is to consider certain factors when determining whether to allow a change in a utility's rates so as to allow the recovery of financing costs.

362. The Parties in this rate proceeding have used a variety of models, methodologies, and assumptions to determine a ROE for Pepco. Given that the cost of equity cannot be observed directly, the Commission must carefully consider both traditional methods and new approaches, when justified. Nonetheless, the Commission has previously addressed concerns with the use of the ECAPM and size adjustments.

363. To be sure, the ultimate ROE set by the Commission must reflect observable market information, including comparisons with equity returns earned by *comparable* companies. There are numerous judgment calls when making those calculations,

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[713] *Hope* at 603.

[714] A "just and reasonable rate" is one that: (1) does not violate any provision of the Public Utility Article of the Maryland Code; (2) fully considers and is consistent with the public good; and (3) will result in an operating income to the public service company that yields, after reasonable deduction for depreciation and other necessary and proper expenses and reserves, a reasonable return on the fair value of the public service company's property used and useful in providing service to the public. PUA § 4-201.

including the selection and weighting of the various methods for comparing companies, the selection of those comparable companies, and the inputs to the various formulae for estimating future cash flows and risk levels. Other possible adjustments to the ROE include the calculation of the flotation costs of issuing new stock, adjustments of the ROE to account for the risk-reducing effects of a BSA or using a MRP, or other rate mechanism, judgments regarding market conditions and the expectations of investors, and other factors that can bear on how the Commission exercises its judgment and discretion on this issue.

364. The Commission is also concerned by the testimony regarding the impact on ROEs of using midpoints versus medians or averages, and the possibility that reliance on midpoints exclusively may give undue weight to outliers and analyst discretion, while undervaluing the distribution of the bulk of data points.

365. The Commission finds, as an initial matter, that Pepco's recommended 10.2 percent cost of equity is unsupported by the record, especially in light of the recent economic market conditions due to the COVID-19 pandemic.

366. The record in this proceeding shows that the overall spectrum of recommended ROEs encompassed Pepco's 10.2 percent (highest), Staff's 9.4 percent, AOBA's 9.25 percent, and OPC's 9 percent (lowest). Staff Witness McAuliffe also offered testimony that the nationwide average of authorized ROEs was 9.44 percent in 2020 for electric utilities.[715] The nationwide average of awarded ROEs for distribution-only electric

[715] McAuliffe Direct at 32

utilities in 2020 was 9.1 and 9.42 percent overall for the 10-year period from 2011 to 2020.[716]

367. Therefore, the Commission finds that an ROE of 9.55 percent for Pepco's distribution service is appropriate, within the zone of reasonableness, and supported by the evidence and consistent with statutory and other legal standards.

368. The Commission finds that the approved ROE is comparable to returns investors expect to earn on investments of similar risk as demonstrated through the use of the witnesses' proxy groups; is sufficient to assure confidence in Pepco's financial integrity; and is adequate to maintain and support Pepco's credit and attract needed capital.

369. The Commission further finds that the ROE approved in this Order is consistent with the nationwide average of awarded ROEs for electric utilities in recent years and at present.

370. Lastly, the approved ROE appropriately accounts for reduced regulatory lag and risk arising from Pepco's decision to request multi-year rates, which will remain fixed over a three-year rate-effective period, based on a forecasted revenue requirement.

371. The Commission also finds that a fixed cost of debt of 4.82 percent for the three-year effective period of the rates approved in this Order is supported by the evidence and provides Pepco with a reasonable opportunity of recovering its actual cost of debt during this MRP. While the Commission acknowledges AOBA's concerns that Pepco's long-term cost of debt has been decreasing in the recent past, AOBA's proposal to adjust the ROR downward each year of the MRP period is denied. The Commission finds that AOBA's analysis does not address the expectations of investors who anticipate

[716] *Id.* at 34.

increasing bond yields in the immediate term or the continuation of decreasing past bond yield performance.

372. The Commission also approves Pepco's proposed capital structure, which was unopposed by the Parties. The long-standing precedent in Maryland is that a utility's actual test-year-ending capital structure should be used when determining its authorized rate of return in a base rate proceeding, absent evidence that the actual capital structure would impose an undue burden on ratepayers. Pepco's proposed capital structure was not challenged by other Parties and is in line with Pepco's actual capital structure and with those historically approved by this Commission. Pepco's approved overall rate of return, based on the Commission's decisions in this case, is 7.21 percent, as illustrated below (Table 9).

Table 9
Summary Overall Rate of Return

Type of Capital	Capitalization Ratio	Embedded Cost Rate	Weighted Cost Rate
Long Term Debt	49.50%	4.82%	2.39%
Common Equity	50.50%	9.55%	4.82%
Total	100.00%		7.21%

C. Cost of Service

1. Jurisdictional Cost of Service

Pepco

373. Pepco witness Wolverton testified regarding the Company's Jurisdictional Cost of Service Study ("JCOSS"), for allocating costs between Pepco's Maryland and District of

Columbia service territories.[717] Mr. Wolverton stated that the jurisdictional allocations and cost assignments in the Company's JCOSS in this case are consistent with those presented in Case No. 9602, which the Commission found to be reasonable.[718] He noted that the allocations in Pepco's JCOSS are driven primarily by direct jurisdictional assignments and allocations of plant and O&M expenses.[719] Mr. Wolverton stated that, as directed in the MRP Pilot Order, Pepco's JCOSS in this case includes the HTY, the bridge year, and the MRP period.[720]

Staff

374. Staff witness Hoppock provided testimony in response to Pepco's JCOSS testimony by Pepco witness Wolverton. Witness Hoppock explained that since Pepco serves electricity distribution customers in Maryland and the District of Columbia, which have separate regulatory entities and rate setting procedures, Pepco must separate costs between the two jurisdictions and set separate distribution rates.[721] He explained further that JCOSS results are used in a class cost of service study (CCOSS), which separates costs between rate classes, and to develop the utility's distribution revenue requirement.[722]

375. Mr. Hoppock stated that in a JCOSS, an allocation is the process of assigning a cost across multiple relevant jurisdictions, and the allocation method or formula should appropriately reflect cost causation principles and other regulatory principles.[723] He

[717] Wolverton Direct at 19-22.
[718] Wolverton Direct at 19, *citing* Case No. 9602 Proposed Order at 134, affirmed by the Commission in Order No. 89227 (Aug. 12, 2019).
[719] Wolverton Direct at 19.
[720] *Id.*
[721] Hoppock Direct at 4-5.
[722] *Id.* at 5.
[723] *Id.* at 6.

noted that his testimony regarding Pepco's JCOSS is limited to the utility's allocation and direct assignment methods.[724] Mr. Hoppock discussed the allocations in Pepco's JCOSS and the trends in allocation between Pepco's Maryland and District of Columbia service territories. He noted that a primary allocation factor in the JCOSS is the AED-NCP (average and excess non-coincident peak demand) allocator, stating that in the timeframe covering the current matter, as well as Pepco's three previous rate cases, Maryland's share of the AED-NCP allocator has been trending downward, while residential and commercial customers in the District of Columbia have been increasing.[725] Therefore, Staff witness Hoppock recommended not using multi-year averaging for any JCOSS allocators, since a JCOSS impacts a utility's revenue requirement, and, according to Pepco's response to a staff data request, a multi-year average AED-NCP allocator could lead to an allocation divergence and resulting over- or under-recovery from Maryland customers relative to District of Columbia customers.[726]

376. However, given that Pepco's proposed direct assignment and allocation methodology is unchanged from Case No. 9602,[727] Mr. Hoppock recommended no adjustments to the Company's JCOSS. He also recommended no adjustments to the allocation methodology for Pepco's accounts.[728]

<u>Commission Decision</u>

377. No Party in this case opposed the Company's JCOSS, and the Commission finds Pepco's JCOSS just and reasonable, as well as consistent with cost assignment and

[724] *Id.* at 6-7.
[725] *Id.*
[726] *Id.*
[727] *Id.*
[728] *Id.* at 10.

allocation the Commission accepted in Case No. 9602. The Company's filing is also consistent with the Commission's MRP Pilot Order filing requirement, with respect to jurisdictional cost studies. Therefore, the Company's JCOSS is adopted for this MRP.

2. <u>Class Cost of Service</u>

<u>Pepco</u>

378. Pepco witness Lance C. Schafer conducted the CCOSS for the Pepco Maryland distribution business. Mr. Schafer explained that a CCOSS allocates Pepco's Test Year adjusted revenue requirement (*i.e.* rate base, revenues, expenses and ratemaking adjustments, or "RMAs") to its customer classes based on cost causation.[729] According to witness Schafer, the historical test period, or the 12-month period ending March 31, 2020, includes 12 months of actual data and rate-making adjustments. He explained that the costs should be appropriately allocated to the classes that cause the utility to incur the costs, and the costs provide a basis to determine the class rate of return results. Mr. Schafer emphasized that the results represent a "snapshot in time" that helps Pepco develop the proposed rates for each customer class.[730]

379. Witness Schafer explained that Pepco adhered to the three traditional steps in the cost allocation process: cost functionalization, classification, and allocation.[731] He stated that Pepco's CCOSS includes two functional categories – subtransmission and distribution – whose rate base and operating expenses are grouped into functional categories depending on their respective uses. He explained further that the functional categories of O&M expenses correspond to plant categories used in the cost analysis and

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[729] Schafer Direct at 5.
[730] *Id.*
[731] *Id.*

include additional O&M functional categories.[732] With regard to the second step, witness Schafer stated that the functionalized rate base and O&M expense items were further classified as either demand- or customer-related, based upon cost causation.[733] He explained that the final step, cost allocation, is where the functionalized and classified costs are apportioned to the appropriate customer classes.

380. Witness Schafer provided details regarding Pepco's Cost of Service model that enabled Pepco to directly assign or allocate each element of rate base, revenues, and operating expenses to the respective customer classes. He described the model as a cost matrix, with the vertical dimension providing an itemized list of the Company's costs to serve its customers and the horizontal dimension consisting of customer classes and their allocated results.[734] He stated that the cost model starts with the rate base details, including each plant account, and continues with the remaining items of rate base (Revenues, Operating Expenses, and Taxes), with the last portion of the cost model presenting the various allocators that form the basis for the CCOSS.[735]

381. Mr. Schafer stated further that the CCOSS uses both internally and externally developed allocators, with 12 internally developed allocators representing one or more previously allocated cost items, and the external allocators developed from data or analyses outside of the CCOSS. According to witness Schafer, once all costs were fully allocated, the resulting costs were aggregated by customer class to determine the overall service cost to that class and to compute the class rate of return.

[732] *Id.,* Schedule (LCS)-5.
[733] Schafer Direct at 6.
[734] *See* Schedule 24 (LCS)-1.
[735] *Id.*

382. Mr. Schafer explained that the Maryland CCOSS recognized and allocated the Company's revenue requirement to the following major retail customer classes: Residential Service ("R"); Time Metered Residential Service ("R-TM"); General Service ("GS, T and OL"); Time Metered Medium General Service, Low Voltage ("MGT LV II," "MGT LV III"); Time Metered Medium General Service, High Voltage ("MGT 3A II," "MGT 3A III"); Time Metered General Service, Low Voltage ("GT LV"); Time Metered General Service, High Voltage ("GT 3B"); Time Metered General Service, Primary Service ("GT 3A"); Time Metered Rapid Transit Service (Schedule "TM-RT"); Street Lighting Service (Schedule "SL"); Street Lights Served from Overhead and Underground Lines (Schedules "SSL-OH" and "SSL-UG"), and Telecommunications Network Service ("TN").[736] He added that, pursuant to Order No. 88997, the CCOSS shows a subsection of the General Service Class, the Public Charging – Plug-In Vehicles ("PC-PIV") subsection, which is an estimate of the cost of providing service to the company-owned PIV chargers. He noted that the CCOSS results shown for this subsection are not being used to inform the rate design for the concerned chargers, since the rates applicable to these chargers are market-based.

383. In this case, Pepco used the CCOSS model it proposed in District of Columbia PSC's Formal Case No. 1156.[737] Mr. Schafer emphasized that although Pepco has proposed a different CCOSS model from its previous Maryland rate proceeding, the allocator assignments have not changed from those used in Case No. 9602.[738] He stated

[736] Schafer Direct at 9.
[737] *Id.*
[738] *Id.* at 10.

that Pepco is submitting one CCOSS to accompany its MRP, and pursuant to Order No. 89482, the CCOSS is based on historical data and is for the duration of the MRP.[739]

384. Witness Schafer detailed the line-item allocations within the CCOSS: the rate base, revenues, operations and maintenance expenses, A&G (administrative and general) expenses, and state and federal income taxes. He summarizes the rates of return resulting from the CCOSS.[740] According to Mr. Schafer, the determinant factor in the new PC-PIV (public charging, plug-in vehicles) class rate of return result is a low load factor combined with a rate structure that collects the cost of demand through a per-kilowatt hour ("kWh") charge.[741] He described the load factor as a measure of average use compared with maximum demand. Witness Schafer states that the PC-PIV class included one charger during the test year, and the class was allocated costs based on a measure of peak demand. However, he explained, those allocated costs were recovered based on kWh sales, which were not high enough to cover the demand-related costs the charger imposed on the system. He explained further that the higher level of demand cost recovery results from an increase in the load factor, because of higher EV charging usage and kWh sales increases.

385. According to Mr. Schafer, with regard to the unbundled cost components noted in the results,[742] the demand and customer cost components are cost-based as determined by the functionalization, classification, and allocation of demand and customer-related cost components in the CCOSS. He elaborated that for each class, the unbundled customer component is calculated by summing the customer-related costs and dividing by the

[739] Case No. 9618, Order No. 89482 at 55.
[740] *See* Schafer Direct at 16, Table 1.
[741] *Id.*
[742] *Id*.

number of customer-months for that class. He explained further that the cost components are calculated utilizing a methodology that is consistent with Case No. 9602. Witness Schafer states that the costs for the test period are summarized and compared to the results from Case No. 9602.[743]

386. Mr. Schafer stated that the unbundled class customer charges have decreased for the Residential, RTM, GS-LV, MGT-LV, GT-LV, GT-3A and GT-3B classes, due mainly to installation decreases, meter reading, records and collections, uncollectible amounts, and "customer other" components.[744] According to witness Schafer, the "customer other" class comprises a portion of storm-related regulatory assets, as well as other associated revenue and expense items.[745] He stated further that for the MGT-HV, Metro, Lighting, and Telecommunications Network Service classes, customer charges have increased since the previous proceeding due to meter, street light and service component increases.[746]

387. According to witness Schafer, Pepco provides historical coincident and non-coincident peak data, kilowatt-hour sales data, historical demand allocator ratios, analysis of the allocators using multi-year data, and the monthly coincident and non-coincident demand data for 2019, as directed by Case No. 9443, Order No. 88432.[747]

[743] *Schafer Direct* at 17.
[744] *Id.* at 18.
[745] *Id.*
[746] *Id.* at 19.
[747] *Id.*

OPC

388. Witness Jerome Mierzwa provided testimony on behalf of OPC regarding his review of Pepco's CCOSS and rate design proposals.[748] He found Pepco's CCOSS to be a reasonable reflection of cost allocation methods consistent with those approved by the Commission in Pepco's five previous rate applications.[749] Witness Mierzwa discussed the role of the three primary steps in the development of Pepco's CCOSS – functionalization, classification and allocation, the 13 customer classes, and the six rate base items in the study, and explained how the major base rate and expense items were allocated to the customer classes.[750] He also reviewed the allocation of depreciation and O&M expenses in the CCOSS, as well as the results of the study, or the class rates of return.[751]

Staff

389. Anna Joy Harris provided testimony on behalf of Commission Staff regarding Pepco's distribution CCOSS. She opposed Pepco's proposed rate of return ("ROR").[752] She instead recommended an adjusted CCOSS that uses Staff's proposed ROR and the average of the last four years of data to determine demand and throughput allocators for all metered classes on a per-customer basis, then multiplying those average values by the average number of customers in each class in the HTY.[753]

390. Witness Harris explained that since Pepco has proposed rates over three years based on four years of forecasts -- the bridge year, 2022, 2023 and 2024 – as well as the

[748] Mierzwa Direct at 3, 8.
[749] *Id.*
[750] *Id.* at 3-6.
[751] *Id*. at 7-8.
[752] Harris Direct at 2.
[753] *Id.*

rate of return – the Staff recommendation of averaging demand and throughput allocators would stabilize year-to-year volatility and reduce cost shifting across rate classes.[754] She noted that the Commission approved this averaging approach in BGE's MRP rate application in Case No. 9645, but the Commission order was published after Pepco filed its application in the present matter.[755]

391. Ms. Harris stated further that Staff's adjustments include Staff witness McAuliffe's recommended ROE of 9.4 percent, and used data from Pepco's filing requirements to calculate the allocators.[756] Witness Harris stated that as a result of the adjustments, the URORs (unitized rates of return) of schedules R, RTM, GS-LV, MGT-LV, MGT-HV, GT-LV, Metro, and Street Lighting E Service have moved closer to 1 percent, and the URORs of Schedules GT-HV-69kV, GT-HV-Other, TN, and PC-PIV have moved further from 1 percent.[757] She added that the Street lighting S Service's UROR did not change.[758]

392. Ms. Harris also recommended that Pepco use a HTY that has been impacted minimally by COVID-19, explaining that Pepco's HTY ended March 31, 2020—COVID-19 started to affect the State in March 2020, resulting in only a month of overlap between the HTY and COVID-19's impacts.[759]

<u>*Rebuttals*</u>

393. Pepco witness Schafer rebutted Staff's testimony regarding the CCOSS and JCOSS. In rebuttal, Mr. Schafer stated that Staff witness Harris had not presented an

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[754] *Id.* at 26-27.
[755] *Id.* at 27; s*ee also* Schedule (AJH).
[756] Harris Direct at 27-28.
[757] *Id.* at 28.
[758] *Id.*
[759] *Id.* at 30.

analysis of Pepco's demand in her testimony and her recommended adjustment should therefore be rejected.[760]

394. Mr. Schafer noted that in Order No. 89678, in which the Commission approved the technique recommended by Staff witness Harris, the Commission found that Staff demonstrated the reasonableness of the four-year average demand and throughput allocators for all metered classes by providing a "detailed analysis of historical data across rate classes."[761] Mr. Schafer argued that Staff witness Harris did not provide any data similar to that which the Commission relied upon in Order No. 89678.[762] However, he stated that evidence in Case No. 9645 (BGE) demonstrated that the historical measures of demand used in the CCOSS might benefit from the application of an averaging technique.[763] He stated that while Staff's recommendation was approved in Case No. 9645, there are material differences between Pepco's and BGE's CCOSSs, as BGE does not utilize an A&E allocator and does not weather normalize its single-year measures of demand.[764]

Surrebuttals

Staff

395. Staff witness Harris filed surrebuttal testimony in response to Pepco witness Schafer's rebuttal testimony. Witness Harris provided an analysis of "the coefficient of variation for the four-year average per-customer demand and throughput allocators for all

[760] Schafer Rebuttal at 3.
[761] *Id.*
[762] *Id.*
[763] *Id.*
[764] *Id.* at 8-9.

metered classes" she calculated in direct testimony.[765] She explained that "[a] low coefficient of variation indicates that there is less fluctuation in the data relative to the average; a higher coefficient of variation indicates that there is more fluctuation in data relative to the average."[766] After Witness Harris compared the results of her analysis to the coefficient of variation results from the BGE Pilot MRP (Case No. 9645) and found them to be similar, she continued to support the use of her proposed allocators.[767]

396. Staff witness Harris also provided a data request from Pepco witness Schafer where he corrected his statement that Pepco uses weather normalized demand data, and noted that Pepco uses actual data.[768]

397. Staff witness Harris also defended the averaging method and the need for a scaling factor in the analysis. She indicates that "[s]caling factors are used in other areas of rate cases, including, but not limited to, four-step rate design when allocating revenue increases to under-earning classes."[769]

Commission Decision

398. The Commission uses cost of service studies *as a guide* in developing customer class rates. In traditional base rate cases the Commission has historically adopted a one-year demand allocator and rejected proposals to use averaged demand allocators due to insufficient evidence.[770] In Case No. 9645, the Commission a cost of service study that used "four-year average demand and throughput allocators for all meter classes on a per-

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[765] Harris Surrebuttal at 3.
[766] *Id.*
[767] *Id.* at 3-6.
[768] *Id.* at 6-7.
[769] *Id.* at 7-8.
[770] Case No. 9406 (Order No. 87591) at 183.

customer basis," after finding Staff provided detailed analysis.[771] The Commission cautioned that the decision should not serve as precedent since it was a pilot case and that there would likely be improvements to the method proposed by Staff.[772]

399. In the current case, Staff witness Harris provided analysis similar to the analysis accepted in the Pilot MRP case as justification for the switch to a form of averaging allocators, and the analysis showed similar results.[773] While this is not the pilot MRP case, this is only the second MRP case reviewed by the Commission and an opportunity to continue exploring improvements to aspects of the rate case in future MRP cases. Therefore, the Commission accepts Staff's proposed CCOSS.

400. As stated in Order No. 89678, the decision to permit allocators based on averages should not be seen as precedential, and there could be further improvements to the CCOSS studies in MRP cases. Future cases should revisit the issue of using allocators based on averages, the impacts of COVID-19 upon the allocators and the appropriateness of using data influenced by COVID-19, and other potential improvements to CCOSS in MRPs.

3. <u>Forecasts and Billing Determinants</u>

<u>Pepco</u>

401. Mr. Barnett discussed the development of PHI's Long Range Plan ("LRP") and Pepco's total LRP O&M used for the MRP proposal; the actual and projected O&M levels at Pepco and PHISCO (a PHI subsidiary) for the non-operational departments; the

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771 Case No. 9645 (Order No. 89678) at 171, para. 370.
772 *Id.*
773 Harris Surrebuttal at 3-6.

actual and projected capital expenditures for IT and Facilities; and Pepco's customer sales growth and revenue projection process for Pepco Maryland.[774]

402. Mr. Barnett explained that the LRP process develops five-year budgets for all PHI companies and details PHI's current corporate structure.[775] According to Mr. Barnett, the LRP, which includes five years of forecasted O&M costs, is used to plan for future expenditures and to manage costs.[776] He stated that a primary goal of the LRP process is "to integrate and align PHI's operational and financial plans," and the operational and financial goals support Pepco's goal to provide safe and reliable electric service to Maryland distribution customers.[777]

403. Mr. Barnett explained that the O&M LRP consolidates the input provided by responsibility areas that review their historical expense levels, performance assessments, regulatory requirements, operational goals, specific projects, and other factors.[778] He stated that the consolidated information is delivered to PHI's senior management for review and approval, followed by PHI Board of Director approval.[779] Mr. Barnett stated that the O&M costs included in the rate application were developed through a budget and planning process, the establishment of responsibility area and project cost budgets, and the addition of financial guidelines.[780] However, according to Mr. Barnett, Pepco is not using its LRP for 2020 but is instead using a forecast of six months of actuals plus six

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[774] Barnett Direct at 2.
[775] In rebuttal testimony, Pepco discussed its plan to separate the Exelon utilities, comprising Pepco and five others, and Exelon Generation, and establish separate parent companies for the six utilities and for Exelon Generation. Pepco expects the separation transaction to be completed in the first quarter of 2022. McGowan Rebuttal at 2-3.
[776] Barnett Direct at 5.
[777] *Id.*
[778] Barnett Direct at 6.
[779] *Id.*
[780] *Id*. at 6-7.

months of estimates (the 6+6 forecast).[781] He explained that Pepco is using the 6+6 forecast because it provides the most recent view of O&M that clarifies the year-over-year changes to the MRP projections for 2021 – 2024.[782]

404. Mr. Barnett discussed the impact of COVID-19 on O&M, including incurring costs for supplies such as masks and cleaning supplies, and the impact of the Commission's moratorium on service disconnections, and noted that Pepco excluded such costs from the MRP projections for 2021 – 2024.[783] He explained that Pepco intends to recover those costs through the COVID-19 regulatory asset mechanism.[784]

405. According to Mr. Barnett, Pepco plans for O&M efficiency savings by developing an O&M LRP to maintain its annual year-over-year increases below the rate of inflation.[785] He stated that Pepco's projected LRP compounded annual growth is significantly below expected inflation rates.[786] Mr. Barnett explained that the process for developing the projected capital costs included in the present filing is similar to that of the O&M process.[787] Mr. Barnett noted that his focus is the projected O&M and capital costs for the following "non-operational" responsibility areas: (1) Communications; (2) Controllership; (3) Executive Management; (4) Finance; (5) Government and External Affairs; (6) Human Resources; (7) Legal; (8) Regulatory; (9) Treasury/Bank Fees; (10) Supply; (11) Support Services; (12) Facilities; (13) BSC, Non-Information Technology; and (14) BSC, Information Technology.[788]

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781 *Id*. at 8.
782 *Id.*
783 *Id*. at 40.
784 *Id.*
785 *Id*. at 41.
786 *Id.*
787 *Id.*
788 *Id.*

406. According to Mr. Barnett, Pepco developed its revenue projection with a forecast of its customer and sales growth and then applied the current BSA.[789] He stated that Pepco economists prepare sales and customer forecasts using estimates of statistical relationships between sales/customers and variables believed to explain sales/customer changes.[790] Mr. Barnett indicated that the models are built at the revenue class levels.[791] He stated that while most of Pepco's customer classes are included in the BSA, for which the only revenue growth driver is customer growth, some customer classes are still based on volumetric rates.[792] He explained that once sales and customer revenue class models are forecasted, they are allocated to tariff level for calculations, and billing demand projections are prepared by applying a historic class level sales load factor to tariff level sales.[793] Mr. Barnett stated that Pepco prepares base distribution revenue forecasts using financial modeling software, and BSA revenues are calculated by multiplying econometric modeling customer forecasts by current BSA targets.[794] He stated further that non-BSA and surcharge revenues are calculated by multiplying energy sales forecasts based on the econometric modeling by current volumetric energy rates.[795]

407. Mr. Barnett described Pepco's inclusion of COVID-19 impacts in its sales, customer, and demand forecasts, stating that Pepco "leveraged the observed experience year-to-date ("YTD"), assumptions around state mandated social distancing and work from home, and the longer-term economic recovery to determine modeling assumptions

[789] *Id*. at 42.
[790] *Id.*
[791] *Id*. at 43.
[792] *Id*. at 44.
[793] *Id.*
[794] *Id*. at 45.
[795] *Id*. at 46.

for future periods."[796] According to Mr. Barnett, Pepco believes COVID-19 is the primary driver of the YTD sales fluctuations, with the impact being experienced predominantly in the second quarter of 2020.[797] He explained that the stay-at-home Executive Orders and required business closures resulted in Pepco Maryland electric sales being 5.7 percent lower than the budget; a 4.8 percent increase in residential sales was offset by an 11.8 percent decrease in commercial and industry sales.[798] Mr. Barnett stated that Pepco Maryland's forecasted 2020 annual weather-adjusted electric sales will be 2.4 percent lower than budget, and Pepco expects a partial sales rebound in 2021 but lower than previously expected by approximately one percent with overall impacts tapering off by late 2021 or early 2022.[799]

Staff

408. Staff witness Hoppock discussed his concerns regarding Pepco's billing determinants forecast and recommended forecasting adjustments. He noted that on December 30, 2020, Pepco provided a detailed description of its forecast allocation process, with supporting information and corrected forecast allocation errors.[800] He added that as part of Pepco's Errata filing on January 11, 2021, the utility provided worksheets detailing out-of-model adjustments to sales models, and later provided worksheets detailing its out-of-model adjustments to customer count models as part of a data request response.[801] Mr. Hoppock noted further that had the Commission not granted a five-week extension to Pepco on January 12, 2021, he would not have had

[796] *Id*. at 47.
[797] *Id.*
[798] *Id*. at 48.
[799] *Id*. at 44.
[800] David Hoppock Direct at 12.
[801] *Id.*

sufficient time to review Pepco's billing determinant forecasts and complete his direct testimony.[802]

409. Mr. Hoppock stated that Pepco has a single residential and commercial revenue class forecasting model for both kWh sales and customer counts, forcing Pepco to allocate forecast sales and customer forecasts across a wide range of tariff classes, including numerous commercial and industrial classes.[803] He noted that with existing divergent and inconsistent trends, the single commercial revenue class model likely was not capturing some of those trends, and the input data for the sales and customer count models may cancel out some of these divergent and inconsistent trends.[804]

410. Mr. Hoppock explained that because Pepco uses a single model for residential and commercial sales and customer counts, the allocation process is more difficult than if Pepco had multiple commercial and residential sales and customer models, and that allocations based on a more granular model would simplify the adjustment of the allocation methodology to be consistent with the historical trends of a smaller group of classes.[805]

411. Witness Hoppock recommended the following: (1) for residential customer counts and forecast kWh sales, the Commission should require Pepco to use separate models to forecast Schedule R and Schedule RTM sales and customer counts in its next MRP rate case; (2) for commercial and industrial classes customer counts and kWh sales, the Commission should require Pepco to use at least four separate models to forecast commercial and industrial rate design tariff classes' kWh sales and customer counts in its

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[802] *Id.*
[803] *Id*. at 22.
[804] *Id*. at 23.
[805] *Id*. at 24.

next MRP rate case; (3) Pepco should use the PC51 working group to explain and receive feedback on what commercial and industrial classes it plans to group within these commercial and industrial models; and (4) the Commission should require Pepco to provide an explanation for its proposed grouping of commercial and industrial classes within its individual commercial and industrial sales and customer count models in future MRP cases.[806]

412. Mr. Hoppock additionally proposed allocating forecasts for residential and commercial revenue class kWh sales based on average weather-normalized kWh sales per customer per year over four years (the 12 months ending March 2020, March 2019, March 2018, and March 2017), multiplied by May 2020 customer counts to allocate commercial and residential class sales in the instant case.[807] Witness Hoppock recommended that the Commission deny Pepco's proposed COVID-19 adjustment to residential sales and customer count forecasts.[808]

413. Additionally, Staff witness Dr. Huilan Li provided her conclusions about Pepco's load forecasting and customer forecasting models, finding that Pepco's forecasting process was insufficiently documented; the residential and commercial sales' empirical functions did not include the summer months of July, August, and September as explanatory variables; the Metro sales forecasting model was the only model that included summer months with correct signs in its empirical function; the Company's residential customer count model using an R-square of 1 was questionable; the R-squared score of (0.995) for the commercial customer empirical function should have been non-

[806] *Id*. at25.
[807] *Id*. at 26.
[808] *Id*. at 27.

farm employment data from IHS Markit (except for time variables); and there was no sensitivity or scenario analysis for any of the forecasting.[809]

a. <u>Residential and Commercial Forecasting</u>

414. Dr. Li reviewed the Company's load forecasting with a focus on the sales forecasting and customer forecasting models. She raised several concerns with Pepco's forecasting. First, Dr. Li noted the Company failed to explain why certain data points were deemed to be outliers and whether those data points were required by either special modeling specification or if the variables were selected by the software.[810] She explained the Company's residential sales model and found Pepco did not provide a reason for using a four-month lag.[811] Dr. Li also found no basis as to why the Company used the explanatory variables of customer numbers and weather as interactive terms rather than being individually represented.[812]

415. Dr. Li indicated that Pepco's estimated sales function demonstrated a relationship between residential sales and ten explanatory variables. She found that only selected months were included as binary variables, and one specific month (month and year) was included.[813] Dr. Li also expressed concern regarding the Company's removal of independent variables during the estimation process, which appeared to be entirely dependent on whether the parameter was statistically insignificant.[814] She stated that Pepco failed to provide details of what econometric considerations were applied.[815]

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[809] Li Direct at 2-3.
[810] *Id*. at 22-23.
[811] *Id*. at 23.
[812] *Id*. at 24.
[813] *Id*. at 25.
[814] *Id*. at 25-26.
[815] Li Direct at 26, *citing* Response to Staff DR 72-1.

416. Dr. Li recommended "that the Company break the interactive terms into three individual independent variables—cooling degree days with temperatures above 65 degrees Fahrenheit, heating degree days with temperatures below 65 degrees, and customer counts to estimate the residential sales function in a scenario analysis and then add two interactive terms back into the equation to determine the best method for incorporating these inputs."[816] Dr. Li suggested that Pepco also should provide documentation and a step-by-step explanation of how it selected the variables.

417. Dr. Li found Pepco's commercial sales forecasting model did not include price as an explanatory variable in the final estimated equation despite economic theory indicating that price is an important determinant of electricity sales.[817] Pepco did not explain why price was not used as an explanatory variable and, similar to the residential forecasting equation, only select months were used as binary variables and three specific months were included.[818] Dr. Li indicated that Pepco should break down the commercial revenue class into several revenue classes based on consumption or national industry code, which should be possible with smart meter data.[819]

b. <u>Customer Count Forecasting</u>

418. Dr. Li explained Pepco's forecasting estimation for both residential and commercial customers. She expressed concern over the Company's use in the estimation equation of the measure – R-Squared Score is 1, which she previously noted was rare, if not impossible, and she found it to be an illogical result.[820] Dr. Li claimed the

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[816] Li Direct at 26.
[817] *Id*. at 27.
[818] *Id*. at 28.
[819] *Id.*
[820] *Id*. at 31.

Company's results suggested randomness that did not exist and lacked any elaboration. In other words, she stated, "that Pepco's residential customer count change is 100% dependent on the non-farm employment data," which is just one factor that drives changes in customer counts.[821]

419. The Company's commercial customer account similarly used the same non-farm employment data with a three-month moving average, but with eight-month lagging terms compared to a three-month lagging that was used for the residential customer count.[822]

c. Software

420. In relation to the software used by Pepco, Dr. Li stated, "It is not clear if the issues I have raised are due to the software and/or choices made by the forecaster."[823] Therefore, she explained, it was imperative a Company forecaster explain why a model was chosen, and the functions and variables that are used.

d. Sales Forecast

421. Dr. Li explained, "The next step was to utilize the estimated function with forecasted input data to get sales forecasts for each revenue function." [824] Pepco's future input data included future prices of electricity, CPI (Consumer Price Index), and forecasted customer counts. However, the Company did not provide either a sensitivity or scenario analysis for any of the forecasting models.[825]

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[821] *Id*. at 31-32.
[822] *Id*. at 32.
[823] *Id*. at 33.
[824] *Id*. at 34.
[825] *Id*.

AOBA

422. AOBA witness Bruce Oliver detailed his concerns with Pepco's billing determinants and forecasting methods in the proposed MRP.[826] Mr. Oliver stated that instead of using its historical billing determinants by rate schedule, Pepco forecast billing determinants for five revenue classes and allocated those results to individual rate schedules.[827] He asserted that Pepco's approach was centered more on overall revenues and less on whether the proposal is reasonable and equitable for each rate class.[828] Mr. Oliver recommended that Pepco refine its forecasting methods to project the number of customers, kWh and any kW demands by rate schedule.[829]

423. Mr. Oliver criticized the methods and assumptions Pepco used to develop its billing determinants forecasts, asserting that they were not reasonable or appropriate.[830] He stated that Pepco used a single forecasting model, with arbitrary and inconsistent allocations, for all its commercial classes, regardless of customer size, service voltage, demand metering or seasonal rate differences, showing a lack of concern for the reasonableness of the rates billed to customers' individual rate classes.[831] He asserted that Pepco's allocations of numbers of customers and kWh from revenue classes, including commercial revenue classes, to rate schedules based on a single historic calendar year are unreasonable, arbitrary and inappropriate.[832] Mr. Oliver also was critical of Pepco using "a single year's annual average relationships between kW and kWh by rate class to forecast future kW billing demands for all years" of the proposed

[826] B. Oliver Direct (Vol. III of III (Part 2) of AOBA Direct) at 30.
[827] *Id.*
[828] *Id.*
[829] *Id.*
[830] *Id*. at 22
[831] *Id*. at 6, 22.
[832] *Id.*

MRP, and questioned Pepco's accuracy in forecasting weather-normalized kWh by rate schedule by month and its practice of forecasting billing determinants based on revenue classes.[833]

Pepco Rebuttal

424. Pepco Rebuttal witness Dr. Ekaterina Efimova provided testimony to explain the methodology Pepco used to perform the billing determinants forecasts the utility used to develop its MRP. She maintained that the forecasts are consistent with accepted utility practice.[834] She also rebutted the billing determinant forecasts testimony by Staff witnesses Hoppock and Li, and AOBA witness Bruce Oliver, and requested that the Commission reject their recommendations.[835]

425. Dr. Efimova explained that Pepco forecasted three sets of billing determinants in developing the MRP: (1) sales; (2) customers; and (3) billing demand. She stated that Pepco uses econometric models to produce the sales forecasts, with the models estimating and forecasting sales by revenue class and statistical relationships between sales and customers.[836] She noted that the residential and commercial models contain variables representing the real price of electricity, weather-related variables, and the number of customers in each class.[837] According to witness Efimova, each equation also contains "dummy" or seasonal variables, as well as corrections and out-of-model adjustments.[838]

[833] *Id*. at 5.
[834] Efimova Rebuttal at 2.
[835] *Id.*
[836] *Id*. at 3.
[837] *Id.*
[838] *Id*. at 4.

426. Witness Efimova noted that Pepco uses a top-down approach in developing its tariff level sales forecasts, meaning the sales forecasts are devised at the higher level revenue and allocates those revenue class level sales down to the more granular tariff level classes by using recent actual customer sales data.[839] She explained that the models econometrically estimate and forecast customers for the residential and commercial revenue classes.[840] Witness Efimova stated that tariff level customer forecasts are similarly developed using a top-down approach.[841] She added that Pepco developed its tariff level electric billing demand forecast methodology by applying an annual historical tariff class level load factor to tariff level sales.[842]

427. Witness Efimova disagreed with Staff witness Hoppock's comments regarding the lack of granularity in the development of Pepco's econometric models and Staff witness Li's recommendations regarding econometric theoretical modeling.[843]

428. Witness Efimova also addressed the testimony of Mr. Hoppock and Mr. Oliver regarding the lack of granularity of Pepco's billing determinants forecasts. She maintained that Pepco's top-down forecasting approach, based on common industry standards, produced reasonable and reliable forecasts.[844] She stated that use of a more granular econometric modeling and smaller customer sample models could result in increased tariff level forecast volatility and, consequently, decrease forecast accuracy.

429. Witness Hoppock provided surrebuttal testimony in response to Pepco witness Efimova's rebuttal testimony on Pepco's billing determinants forecast. He stated that his

[839] *Id*. at 5.
[840] *Id.*
[841] *Id*. at 6.
[842] *Id*. at 7.
[843] *Id.*
[844] *Id*. at 12.

positions—as articulated in his direct and rebuttal testimony—remained unchanged following Pepco's rebuttal testimony.[845] He addressed witness Efimova's response to his recommendation for more granular modeling of residential and commercial forecasting for the MRP, in which she maintained that Pepco's top down forecasting method is reasonable and widely used among electric utilities.[846] He responded that his recommendation was specific to Pepco and noted that BGE, which also filed an MRP case, conducts more granular modeling.[847] He concluded that it was reasonable to require Pepco to conduct more granular forecasting for the next MRP rate case, so that the forecasting models better reflect their applicable tariff level classes.[848]

430. Mr. Hoppock disagreed with witness Efimova's testimony that Pepco's previous forecast variances, relative to actuals, were within reasonable bounds, stating that Schedule RTM actual customer counts were over 20 percent higher than forecast in two years, and GT-3B sales forecasts have deviated by more than 10 percent for four of the last 10 years.[849] He added that the Pepco data compares actual to the prior year forecast, and forecasting into the future is more difficult than shorter term forecasting because of potential uncertainties regarding key forecast assumptions and inputs.[850]

431. Mr. Hoppock concluded that, based on Pepco witness Efimova's description of Pepco's forecasting at a high level, Pepco is using historical data to develop linear regression models that establish relationships between key explanatory variables and

[845] Hoppock Surrebuttal at 49.
[846] *Id.* at 40.
[847] *Id.* at 40-41.
[848] *Id.* at 51.
[849] *Id.* at 48.
[850] *Id.* at 48-49.

other explanatory variables, and sales and customer counts.[851] Therefore, he stated, it was crucial that the historical data used reflect the trends and relationships between dependent and independent variables at the tariff level.[852] He added that if a model is used to forecast tariff class billing determinants with data that do not reflect such trends and relationships, the model will likely have limited value as a forecasting tool for that tariff class.[853] Witness Hoppock concluded that Pepco's forecasting model had no value in forecasting Schedule RTM customer counts for this MRP.[854]

432. Witness Hoppock stated that Pepco agreed with his recommendation to review its regression models and report any improvement in future MRP filings.[855] He concluded that Pepco's method for aggregating commercial and residential classes into commercial and residential revenue classes to develop linear regression forecasts uses input data that, for multiple tariff classes, does not represent historical sales and customer count trends for these classes and relationships with explanatory variables for these classes.[856]

433. Witness Li also provided surrebuttal testimony in response to Pepco witness Efimova's rebuttal testimony. Dr. Li emphasized that her previous findings and recommendations were unchanged from her direct testimony; however, she clarified several of her observations as described below.

434. Witness Li stated that Dr. Efimova's testimony shed light on Pepco's forecasting methodology, and the additional information enabled Staff to better understand the

[851] *Id.* at 23.
[852] *Id.*
[853] *Id.*
[854] *Id.* at 50.
[855] *Id.* at 49.
[856] *Id.* at 51.

methodology.[857] Dr. Li explained that the information Pepco initially filed was incomplete and, in some cases inaccurate, necessitating several data requests from Staff prior to responding to witness Efimova's testimony.[858]

435. Dr. Li stated that Dr. Efimova's descriptions of Pepco's sales and customer econometric methodology were consistent with Dr. Li's discussion in her direct testimony, except Dr. Li found her own discussion to be more thorough, and thought Dr. Efimova's testimony did not provide a complete picture to understand Pepco's modeling.[859] For instance, witness Li stated that Pepco did not include a written narrative document with its load forecasting file and did not explain the dummy variables, trend, and other variables included in Pepco's methodology.[860] Dr. Li stated further that Pepco's methodology included six forecasting functions, but Dr. Efimova's response to a Staff data response did not elaborate on those functions.[861] Witness Li stressed that forecasting documentation, including a conceptual model and written narrative with explanations, is essential.[862]

436. She stated that she provided an econometric forecasting process overview in her testimony after reviewing Pepco's load forecasting and determined that she did not fully understand Pepco's process, "even though Staff and the Company had frequent and numerous communications."[863] Witness Li disagreed with witness Efimova's characterization of her rebuttal testimony as theoretical and a misinterpretation of

[857] Li Surrebuttal at 3.
[858] *Id.*
[859] *Id.* at 3-4.
[860] *Id.* at 4, 8.
[861] *Id.* at 5.
[862] *Id.* at 6.
[863] *Id.*

information that Pepco had provided.[864] She stated that she instead provided a general review, intended as a practical guide, in layman's terms.[865]

437. Witness Li stated that a Staff-requested meeting with Pepco on December 11, 2020, and Pepco's responses to Staff data requests, assisted her in understanding the methodology better, but she did not find all of Pepco's explanations to be satisfactory. For example, she explained, a Staff Data Request asked, in part, why price was excluded from the commercial sales forecasting equation, and Dr. Efimova's response was that the independent variable of price was excluded due to its unexpected sign estimated by the model.[866] Witness Li stated that the explanation helped her to realize that the price was excluded due to the positive sign of the estimated price coefficient, which led to other questions, such as why Pepco's other three sales forecasting models included price as an independent variable.[867] Dr. Li suggested that while Pepco should rely on its internal documentation for load forecasting, the Company also should provide in its filing a narrative—written in layman's terms and with technical details explained—to help regulators, intervenors, and the public understand its forecasting process. [868]

AOBA

438. AOBA witness Oliver provided surrebuttal testimony in response to Pepco witness Efimova. Mr. Oliver challenged Dr. Efimova's statements that Pepco used industry standard modeling techniques for its load forecasting.[869] He described AOBA's data request, in which AOBA asked Pepco to provide documentation that Dr. Efimova

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[864] *Id.* at 7.
[865] *Id.*
[866] *Id.* at 14.
[867] *Id.* at 15.
[868] *Id.* at 21.
[869] B. Oliver Surrebuttal at 17.

relied upon, to determine what is considered industry standard modeling techniques, and to provide documentation of any independent review that determined the Exelon Load Forecasting team's modeling techniques conform to an industry standard.[870]

439. According to Mr. Oliver, Dr. Efimova's response to the first request was that industry standard "was one of the commonly accepted utility practices utilized by the Company, and the response to the second request was that no such documents existed."[871] Mr. Oliver stated further that the response included a link to a NARUC study to support Pepco's use of top down forecasting in utility forecasting, but he emphasized that the study did not contain any references to industry standard load forecasting techniques and in fact includes a statement that a workable model for one utility may not work best for another.[872]

440. Witness Oliver added that the NARUC study did not contain any conclusions or recommendations regarding appropriate forecasted tariff class billing determinants to employ for rate design.[873] He maintained that top-down forecasting methods do not yield reasonable or acceptable service requirement forecasts for tariff level rate cases, and the Commission should not accord any value to witness Efimova's representations regarding best practices for load forecasting methods.[874]

441. Witness Oliver found the historical load factors presented by witness Efimova in her rebuttal not to be appropriate measures of class load factors, and that her load factor

[870] *Id.*
[871] *Id.* at 18.
[872] *Id.*
[873] *Id.* at 19.
[874] *Id.* at 20.

calculations were incorrect.[875] He stated that witness Efimova inverted the relationship between demand and kWh and did not consider the number of hours in each period, and also that the results do not properly depict variation in load factor.[876] Witness Oliver also questioned Pepco's method for estimating customer numbers and the method Pepco used to estimate electric price data for future periods.[877]

Commission Decision

442. The Commission shares the concerns raised by Staff witnesses Li and Hoppock and AOBA witness Bruce Oliver regarding the accuracy and granularity of the Company's forecasts. Reliable and reasonable forecasts are essential to the development of a MRP and resulting rates. Fortunately, Mr. Hoppock was able to make enough adjustments to the billing determinant forecasts to allow the Commission to salvage the proposed MRP. However, Pepco and all future utilities that apply for MRPs are reminded of the need to provide transparent and robust documentation in support of their forecasts from the very beginning of the rate case. The Commission will not accept MRPs without fully supported forecasts. Improved access to the models is also necessary for parties to understand and verify the accuracy of the proposed forecasts. If not for the five-week extension in this case, Staff would not have had enough time to complete its analysis of Pepco's forecasts, and the Commission would have had no alternative but to reject this rate application.[878]

443. Pepco's forecasting information when filed lacked sufficient information for a complete analysis and lacked the granularity that would have simplified the development

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[875] *Id.* at 29.
[876] *Id.*
[877] *Id.* at 27-28.
[878] *See* Hoppock Direct at 12.

of billing determinants. Fortunately, the necessary information was provided before the conclusion of the procedural schedule and the lack of granularity does not, in this case, prevent the production of just and reasonable tariff allocations. For this reason, the Commission approves Staff's recommendations. Directing Pepco to adhere to Staff's recommendations should prevent similar issues with granularity if Pepco chooses to file another MRP. The Commission also directs Pepco to file a report by June 30, 2022 with recommendations on grouping C&I classes for C&I kWh sales and customer count models on behalf of the Public Conference 51 Work Group, as recommended by Staff.

D. Rate Design

1. Revenue Allocation

444. Pepco witness Peter R. Blazunas[879] described the utility's proposed rate design, discussed the effects of the proposed rate changes on Pepco's major rate schedules and described the revised tariff sheets based on the proposed changes to the distribution rates.[880]

445. He explained that Pepco used a four-step revenue allocation methodology, beginning with summarizing the rate class-specific distribution revenue, net operating income, net rate base, rate of return, and UROR results from the CCOSS for the historical test year.[881] Mr. Blazunas stated that the four steps consist of: (1) Determining which rate classes have a relative rate of return that is significantly higher than the system average rate of return, and excluding any such classes from any distribution rate

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[879] Pepco witness Matthew K. Bonikowski adopted the Direct Testimony of Peter R. Blazunas. However, since in its briefs Pepco maintained the references to "Blazunas Direct", this reference will be maintained in the Commission's decision. See Pepco Initial Brief at 67, n. 338.
[880] Blazunas Direct at 2.
[881] Specifically, the 12-month period ending March 31, 2020. Blazunas Direct at 7.

allocation; (2) Determining which rate classes have a relative rate of return that is close to the system average rate of return, and allocating to any such classes a percentage increase equal to the overall system average increase; (3) Determining which rate classes have a relative rate of return significantly lower than the system average rate of return, and allocating to any such classes a percentage increase greater than the overall system average increase; and (4) Allocating to any remaining rate classes, which have not been excluded from the increase in Step 1, or allocated an increase in Step 2 or 3, an increase of the remaining revenue to be collected in proportion to their current level of annualized distribution revenue.[882]

446. Mr. Blazunas stated that Pepco relied on the ratemaking principles of cost causation and gradualism that the Commission has encouraged in its recent rate decisions and utilized a UROR Steady State equal to +/- 10 percent of the system average rate of return, consistent with Pepco's application of the four-step method in recent proceedings.[883]

447. According to Mr. Blazunas, Step three of the four-step allocation method applies a Multiplier of 1.17 to the System Average Increase, based on the results of the Class Rates of Return Analysis and Pepco's review of prior Commission rate cases where revenue increases were allocated to under-earning rate schedules, relative to the total system increase.[884] Mr. Blazunas explained that its proposed method facilitates

[882] Blazunas Direct at 8.
[883] *Id.* at 8-14.
[884] *Id.* at 16.

movement towards a more equalized UROR among the rate classes, in addition to incorporating cost causation and gradualism principles.[885]

448. According to Mr. Blazunas, the total revenue requirement for each year of the MRP totals Pepco's current annualized distribution revenue and the allocated amount of the revenue increase, plus offsets for each rate schedule.[886] He explained that the proposal allows all classes to receive a full offset to their cumulative distribution revenue requirement increases in Rate Years 1 and 2, and an approximately 50 percent offset in Rate Year 3, with a resulting net revenue increase of approximately $55.888 million for Rate Year 3.[887] He noted that the proposed MRP consequently results in no overall customer distribution rate increase for the first two rate years, and a partial distribution rate increase in the third year of the MRP.[888]

449. Staff Witness Hoppock proposed using a two-step method to allocate revenues. He explained that his proposed rate design uses the results of Staff witness Harris' adjusted CCOSS, his recommended adjustments to Pepco's billing determinant forecasts and the proposed revenue requirement of Staff witness Patterson.[889] Mr. Hoppock's proposal sets rates for each rate year and offsets all rate increases.[890]

450. In Step 1 of Staff's two-step method, 25 percent of revenue requirements are allocated to under-earning classes based on relative historical test year annualized distribution revenue; in Step 2, the remaining 75 percent is allocated to all classes other

[885] *Id.*
[886] *Id.* at 18; *see,* Schedule (PRB)-4.
[887] Blazunas Direct at 20.
[888] *Id*. at 22.
[889] Hoppock Direct at 55.
[890] *Id.*

than Schedules GT-3B and TN, which are highly over-earning.[891] Staff explained that its two-step method results in lower maximum bill impacts, increases the UROR of all under-earning classes, and decreases the UROR of all over-earning classes.[892]

451. OPC witness Mierzwa reviewed Pepco's proposed four-step revenue allocation methodology and found that the proposed revenue distribution, with an increase of $55,888,183, or 10.2 percent over present rates, to be reasonable.[893] Lastly, Mr. Mierzwa examined Pepco's proposed rate design for residential customers under the MRP, noting that Pepco proposes to maintain the fixed monthly charge and variable delivery service charge and to avoid revenue increases until 2023, with delivery charges increasing for all three years of the MRP.[894]

452. AOBA witness Timothy Oliver stated that Pepco's revenue allocation methodology contained many things that AOBA has supported in previous rate cases including the +/- 10 band allocation proposal.[895] Witness Oliver also found that the methodology was useful for comparison, but he did not support the 1.17 multiplier for classes significantly below the system average rate of return, stating it "is based solely on the residential class's percent allocation over the last four rate cases and is therefore not cost based when applied to the MGT-3A."[896] Using Pepco's method with AOBA's proposed revenue requirement, witness Oliver found that the Company's proposed methodology produced an increase of 10.17 percent compared to 20.34 percent.[897]

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[891] *Id*. at 12.
[892] *Id.*
[893] Mierzwa Direct at 11.
[894] *Id*. at 12.
[895] T. Oliver Direct at 38.
[896] *Id*. at 38-39.
[897] *Id*. at 39.

453. Pepco witness Bonikowski adopted Mr. Blazunas' direct testimony and in his rebuttal testimony also provided updated details about the proposed revenue allocation method and rate design.

454. Mr. Bonikowski found that Staff witness Hoppock's proposed two-step revenue allocation methodology was reasonable and similar to Pepco's four-step method but maintained that Pepco's proposed four-step revenue allocation methodology is more flexible than the two-step approach, facilitates more consistent revenue allocations across rate cases, and produces results that comport with Commission precedent.[898] He stated that Mr. Hoppock's proposed two-step methodology would yield an effective distribution revenue increase for under-earning classes that is 1.13 times the system average increase, which he describes as an overly conservative result where all classes are moving toward a UROR of 1 percent at a slower rate than Pepco's proposal.[899]

455. Mr. Bonikowski stated that Pepco's four-step methodology addresses issues that arose with the two-step method.[900] He explained that in the two-step methodology, the percentage of the revenue increase assigned in the first step is the only mechanism for determining the proportion of revenues allocated to under-earning and over-earning classes.[901]

456. According to witness Bonikowski, another issue is that the multipliers to the system average increase for under-earning classes are an output of the first step percentage and cannot be set to reflect Commission precedent.[902] Additionally, he stated,

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[898] Bonikowski Rebuttal at 5.
[899] *Id.*
[900] *Id*.
[901] *Id.*
[902] *Id.*

the first step percentage increase is seldom consistent across rate cases due to differences in case-specific variables.[903]

457. Pepco's proposed four-step methodology addresses these issues by using three explicit input criteria: (1) the UROR threshold for a rate class to be excluded from receiving a revenue requirement increase in Step 1; (2) an upper and lower UROR limit for a class to be assigned a steady state adjustment in Step 2; and (3) the multiplier to the system average increase applied to under-earning classes in Step 3.[904] Mr. Bonikowski stated that the expanded inputs provide a more targeted allocation of the revenue requirement to both under- and over-earning classes, and using the multiplier as an input allows for an easier comparison of parties' proposed revenue allocations both within a given case and compared to prior Commission decisions.[905]

458. Mr. Bonikowski also disagreed with AOBA witness Oliver's position that the 1.17 multiplier used in the four step methodology was based only on the residential class for the last four rate cases and stated that the 1.17 average was based on the multiplier applied to all under-earning classes.[906] Mr. Bonikowski also indicated that MGT-3A was assigned a 1.27 system average increase in Case No. 9602.[907]

459. Mr. Oliver disagreed with Mr. Bonikowski's characterization of his statement regarding the non-cost based nature of the 1.17 multiplier for MGT-3A. Mr. Oliver claims he did not assert that the multiplier was inappropriate for MGT-3A.[908] Mr. Oliver states that the historically based allocation percentages are not based on expected costs in

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[903] *Id.*
[904] *Id.*
[905] Bonikowski Rebuttal at 5-6.
[906] *Id*. at 9.
[907] *Id.*
[908] T. Oliver Surrebuttal at 6.

the multi-year rate plan.[909] Mr. Oliver summarized that the disconnect between the revenue based forecasts and revenue distribution will increase the likelihood that the proposed revenue distribution will be inaccurate and of classes moving away from the system average return at the end of the MYP.[910]

Commission Decision

460. While Pepco witness Bonikowski believed his method to be more appropriate for rate design, he acknowledged that Staff witness Hoppock's proposed two-step methodology is reasonable. The Commission also notes that only one class is impacted by the 10 percent band proposed by Pepco witness Bonikowski's four-step method. The Commission sees no reason to deviate from its current practice of using the two-step method to allocate revenue and therefore approves Staff 's recommendation of the two-step revenue allocation method, which allocates 25 percent of the revenue in step 1 for under-earning classes. The allocation in step 1 balances reduction of interclass subsidization with gradualism.

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[909] *Id.*
[910] *Id.*

Table 10 Estimated UROR Results		
Rate Schedule	**Current**	**Proposed**
R	0.88	0.93
RTM	0.91	0.94
GS-LV	1.28	1.23
MGT-LV	1.23	1.13
MGT-3A	0.67	0.71
GT-LV	1.39	1.26
GT-3B	5.28	4.26
GT-3A	0.82	0.85
TM-RT	0.74	0.75
SL	0.79	0.80
SSL	(0.10)	0.15
TN	2.60	2.10

2. Intra-Class Rate Design Issues

461. Mr. Blazunas detailed Pepco's calculation of its proposed base rate structures for each rate schedule, stating that the utility determined the level of the customer charge, the demand charge and volumetric charge based on the Commission principle set forth in recent rate cases of placing a greater emphasis on volumetric charges and less emphasis on customer charges.[911]

462. Pepco Witness Blazunas emphasized that Pepco does not propose any customer charge increases for any rate schedules in Rate Years 1 and 2.[912] He added that for Rate Year 3, Pepco uses a 2.64 percent increase for rate schedule R and a 2.84 percent increase

[911] Blazunas Direct at 23.
[912] *Id*. at 25.

for all other rate schedules, except for rate schedule TM-RT. He explained that these increases will develop the level of customer charges for each of the various rate schedules.[913]

463. Mr. Blazunas noted that Pepco does not propose a demand charge increase for any rate schedule in Rate Years 1 and 2.[914] He explains that the demand charge for Rate Year 3 is determined for rate schedules with a three-part rate structure by: (1) subtracting from total proposed revenue the amount of revenue collected through the proposed customer charge, and then (2) multiplying the remaining amount by the proportion of current revenue from the current demand charge, relative to the total amount of revenue collected from the current energy and demand charges.[915]

464. Mr. Blazunas noted that in Step Three, for rate schedules without a demand charge component (or a two-part rate structure), the remaining distribution revenue requirement, after determining the customer charge, is recovered through a volumetric rate increase.[916] He added that for rate schedules with a demand charge component, or three-part rate structure, the remaining distribution revenue requirement, after determining the customer charge and demand charge, is recovered through a volumetric rate increase.[917] He stated that for both rate structures, the winter and summer volumetric rates are designed to maintain their current relationship with one another.[918]

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[913] *Id.*
[914] *Id.* at 26.
[915] *Id.*
[916] *Id.* at 27.
[917] *Id.*
[918] *Id.*

465. Staff witness Hoppock agreed with Pepco's proposed increases to the customer charge based on increases from previous cases.[919] He also accepted Pepco's method for maintaining the relative percent of revenue recovered from demand and volumetric charges as well as winter and summer rates.[920]

466. OPC witness Mierzwa recommended that Pepco's proposed Rate Schedule R and RTM monthly customer charge increases not be accepted, stating that they are inconsistent with Commission policy to minimize customer charge increases in order to maximize residential customers' ability to control their expenditures through conservation.[921]

467. AOBA witness Bruce Oliver was critical of Pepco's representation that no structural changes were occurring to the rate design of individual rate schedules. Witness Oliver finds that Pepco's proposal is indeed making significant changes to the volumetric rates relative to the demand rates and that no cost-based defense was presented to justify the increasing kWh charges without adjusting the corresponding kW charges. [922] As a result he believes that the proposal unduly discriminates against higher load factor customers.[923]

468. Mr. Bonikowski responded to OPC's recommendation to deny Pepco's requested customer charge increases for the residential classes. He argued that Pepco's proposed

[919] Hoppock Direct at 61.
[920] *Id.* at 61
[921] Mierzwa Direct at 12-13.
[922] B. Oliver Direct, Part 1 at 57-58.
[923] *Id.* at 58.

increases to Schedule R and R-TM customer charges are identical to the percent increases approved by the Commission in Case Nos. 9602 and 9443.[924]

Commission Decision

469. The Commission adopts the proposed customer charges proposed by Pepco witness Blazunas and supported by Staff witness Hoppock. When setting customer charges, the Commission balances the principles of cost causation against the principle of gradualism and maintaining an incentive for customers to conserve energy and maintain control over their bill. The Commission believes the adopted customer charges achieve this balance. However, the Commission directs these charges to go into effect in year two of the MRP and not year three.

Table 11
Current and Proposed Customer Charges (Yr2)

Rate Schedule	Current Customer Charge	Proposed Customer Charge Year 2
R	$ 8.01	$8.22
RTM	$17.25	$17.74
GS-LV	$11.97	$12.31
T	$12.16	$12.51
EV	$4.50	$4.63
MGT LV	$44.96	$46.24
MGT 3A	$42.70	$43.91
GT LV	$365.32	$375.70
GT 3B	$321.97	$331.11
GT 3A	$343.01	$352.75

[924] Bonikowski Rebuttal at 8.

470. The Commission notes that AOBA witness Oliver also raised concerns that Pepco's proposed rate design for demand charge customers was inappropriately shifting the revenue recovery between volumetric and demand charges such that higher load factor customers would be unfairly burdened without sufficient justification. While testimony from Staff and Pepco both appeared to agree that they have similar approaches to setting demand charges, it is not clear since Staff's proposed demand charges change every year while Pepco's remain constant until Rate Year 3. After examining Staff witness Hoppock's Surrebuttal exhibits, it appears his proposed rate design is increasing volumetric and demand charges by a similar percentage each year.[925] Therefore, the Commission agrees that without additional justification, revenue recovery relationship between demand and volumetric rates should remain the same at this time and the Commission adopts Staff's proposed methodology for setting demand and volumetric charges for doing so.

3. BSA and EBSA

471. Pepco witness Blazunas noted that the specific components of Pepco's proposed class rates as established through the proposed rate design are utilized in the utility's development of its proposed monthly BSA revenue per customer targets.[926] Mr. Blazunas explained that the Commission-authorized BSA is a revenue decoupling mechanism that removes the link between electricity use and utility distribution revenue.[927] He stated that the BSA applies only to the distribution portion of the bill and adjusts monthly to lower customer rates if Pepco receives more distribution revenue than

[925] For example, *see* Hoppock Surrebuttal at Exhibit DH-6-SR: Staff Surrebuttal Rate Design Worksheets and Bill Impact Analysis, MGT-LV at 1-6.
[926] Blazunas Direct at 24.
[927] *Id.*

the Commission has approved on the basis of a target level of distribution revenue per customer, and will increase rates if the Company is receiving less distribution revenue than the Commission has approved on the basis of a target level of distribution revenue per customer.[928] Mr. Blazunas indicated that Pepco's proposal maintains the BSA during the MRP.[929]

472. Mr. Blazunas emphasized that while Pepco does not propose an increase to its distribution revenue requirement for the first two rate years, new base distribution rates will be established for those rate years to account for forecasted changes in revenue authorized by Case No. 9602 and forecasted billing determinants.[930] He explained that volumetric rates in the first two rate years are adjusted so that proposed rates multiplied by forecasted billing determinants will yield Pepco's forecasted level of authorized Case No. 9602 revenue.[931] Mr. Blazunas added that this "Effective Bill Stabilization Adjustment" is included in the design of the Company's proposed base distribution rates for Rate Year 1 and Rate Year 2.[932] He added that Pepco is not proposing any structural changes—changes to the number or to the type of distribution rate components—to the rate design for any rate schedule during the MRP.[933]

473. Staff witness Hoppock's EBSA proposal limits the Effective Bill Stabilization Adjustment ("EBSA") to 10 percent of current rates.[934] He additionally proposed that unrecovered revenue due to the EBSA cap or revenue not returned to customers be added

[928] *Id.*
[929] *Id.*
[930] *Id*. at 27.
[931] *Id.*
[932] *Id.*
[933] *Id.*
[934] Hoppock Direct at 3.

to the Rider "BSA" deferred revenue balance for that class in order to be recovered or returned to customers through monthly Rider "BSA" rate adjustments.[935]

474. Mr. Hoppock recommended that the Commission limit any change in volumetric distribution rates due to the Effective BSA to 10 percent of current rates in Rate Year 1 rates, 10 percent of Rate Year 1 rates in Rate Year 2, and 10 percent of Rate Year 2 rates in Rate Year 3.[936] He explained that for Rate Year 1, Pepco proposes rate changes in excess of 10 percent for multiple classes and as high as a 16.7 percent increase for Schedule MGT-LV due to the Effective BSA, before applying any revenue requirement.[937] He emphasized that this substantial range in EBSA is likely partially because of Pepco's forecasting method, which aggregates all commercial and industrial classes into a single forecasting model for kWh sales and customer counts.[938]

475. Mr. Hoppock added that the size of Pepco's proposed Effective BSA increases in Rate Year 1 is inconsistent with the adjustments in BGE's MRP case and Pepco's most recent rate case, and inconsistent with Rider "BSA," which helps to protect against rate shock.[939]

476. Mr. Oliver testified on AOBA's position regarding Pepco's BSA mechanism and its continuation.[940] Mr. Oliver stated that Pepco uses a single forecasting model for all commercial classes regardless of customer size, service voltage, demand metering or seasonal rate differences, showing a lack of concern for the reasonableness of the rates

[935] *Id*. at 56.
[936] *Id.*
[937] *Id.* at 57.
[938] *Id.*
[939] *Id.*
[940] B. Oliver Direct (Part II, Vol. III) at 2.

billed to customers' individual rate classes.[941] He asserted that Pepco's allocations of numbers of customers and kWh from revenue classes, including commercial revenue classes, to rate schedules based on a single historical calendar year are unreasonable, arbitrary and inappropriate.[942] Mr. Oliver also was critical of Pepco using "a single year's annual average relationships between kW and kWh by rate class to forecast future kW billing demands for all years" of the proposed MRP, and questioned Pepco's accuracy in forecasting weather-normalized kWh by rate schedule by month and its practice of forecasting billing determinants based on revenue classes.[943]

477. Mr. Oliver's concerns extended to Pepco's proposed BSA mechanism, which he asserted is not designed to address "under-recoveries" in COVID-19-related revenues and would adversely impact operators of master-metered apartment buildings that are billed under commercial rate schedules.[944] He stated that Pepco's BSA mechanism is designed to provide reconciliations of authorized and actual revenue collections after the fact, and that Pepco is using BSA-related considerations to adjust rates for assumed future revenue collection shortfalls.[945]

478. Pepco witness Bonikowski stated that witness Hoppock's recommended 10 percent volumetric distribution rate cap due to the EBSA was unreasonable on its face and should be rejected.[946] He contended that in any rate case, the rates must be designed to recover the full authorized revenue requirement, and witness Hoppock's proposal fails because it has the potential to produce rates that over-collect the approved revenue

[941] *Id.* at 6.
[942] *Id.*
[943] *Id.* at 5.
[944] *Id.* at 4.
[945] *Id.* at 5.
[946] Bonikowski Rebuttal Testimony at 11.

requirement for some rate classes, while under-collecting the approved revenue requirement for others.[947] Witness Bonikowski requested that if the Commission accepted Mr. Hoppock's recommendation, Pepco be authorized to address any revenue under- or over-recovery related to the cap through the BSA.[948] Mr. Bonikowski also denied Mr. Hoppock's claim that Pepco proposed to apply EBSA adjustments to non-BSA classes, stating that those classes do not have a BSA revenue per customer target.[949] Mr. Bonikowski clarified that Pepco instead applies a target revenue adjustment to non-BSA classes, and absent that adjustment, proposed rates would not collect Pepco's full incremental revenue requirement.[950]

479. Witness Bonikowski disagreed with AOBA witness Oliver's recommendation that the Commission deny Pepco's use of the EBSA, explaining that the EBSA adjusts base distribution rates so that, based on forecast billing determinants, proposed rates will collect no more or less than the revenues authorized by the Commission.[951] He added that if the Commission disallowed the EBSA, the result would be rates that under- or over-collect revenues.[952]

480. Staff witness Hoppock responded to AOBA witness Oliver's EBSA recommendation. He argued that if the EBSA is not included in the MRP, then the baseline revenue will decrease for the BSA rate classes resulting in higher revenue requirements.[953]

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[947] *Id.* at 12.
[948] *Id.* at 13.
[949] *Id.* at 13-14.
[950] *Id.* at 14.
[951] *Id.* at 15.
[952] *Id.*
[953] Hoppock Rebuttal Testimony at 3.

481. Witness Hoppock provided surrebuttal testimony in response to Pepco witness Bonikowski's rebuttal testimony regarding Mr. Hoppock's recommendation to cap rate changes at 10 percent due to the EBSA. Witness Hoppock stated that Pepco's proposal would offset some or all of its calculated distribution rate increases until after Rate Year 3, offsetting the recovery of Pepco's requested revenue until after the MRP.[954] He explained that the proposed offsets effectively hide from customers the impact of Pepco's requested revenue requirement and will result in effective rates, net of offsets, that differ from Pepco's proposed tariffed rates over the entire MRP.[955] However, he stated that his proposed EBSA cap only impacts Rate Year 1 rates, and he proposed the cap to preserve the protections within the BSA.[956] He emphasized that Pepco's proposed EBSA adjustments in Rate Year 1, which are not offset by the utility's proposed Rider ERR, are as high as 7 percent.[957]

482. Witness Hoppock agreed with Pepco witness Bonikowski's proposal that if the Commission approves Mr. Hoppock's recommended cap on volumetric distribution rate changes due to the EBSA, the Commission should authorize Pepco to address any over or under recovery resulting from a cap through the BSA.[958] He stated that this recommendation was consistent with his direct testimony proposing that the unrecovered or unreturned revenue be added to the Rider "BSA."[959]

483. AOBA witness Oliver stated that witness Bonikowski's testimony adds *substantive* and "belated" changes to Pepco's rate proposals, limiting the ability of

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954 Hoppock Surrebuttal Testimony at 4.
955 *Id.*
956 *Id.*
957 *Id.*
958 *Id.* at 5.
959 *Id.*

intervenors like AOBA to respond.[960] Witness Oliver argued that Pepco's use of EBSA in Schedule (MJB-R)-7 is different from its use of similarly labeled entries seen in Pepco witness Blazunzas' revised schedule (PRB)-7 that accompanied Pepco's December 30, 2020 errata filing.[961] He stated further that Pepco chose not to file supplemental direct testimony but instead waited until filing rebuttal testimony to make the substantive changes to its rate design presentation.[962]

484. According to witness Oliver, the significant changes comprise Pepco's effort to expand the applicability of the ERR Rider credits to Rate Years 1 and 2, and substantial changes to its EBSA amounts, particularly for Rate Years 2 and 3.[963]

485. He stated that Pepco's BSA mechanism involves a monthly adjustment of Pepco's authorized revenues based on the actual numbers of customers for each BSA rate class with Pepco's actual revenue collections for each class.[964] He added that the reconciliations are meaningful after the fact, and no Commission determinations or orders require the use of forecasted numbers of customers in the determination of current authorized revenues in a base rate proceeding.[965]

486. Witness Oliver further stated that should the Commission allow the BSA as proposed, BSA reconciliations would become a process in which estimates of revenue are reconciled with actual revenue collections, as opposed to matching the impact of actual numbers of customers with actual revenues.[966]

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[960] B. Oliver Surrebuttal Testimony at 32.
[961] *Id.*
[962] *Id.*
[963] *Id.* at 33-34.
[964] *Id.* at 35.
[965] *Id.* at 35-36.
[966] *Id.* at 37.

Commission Decision

487. The Commission agrees with Staff that -- in this case -- it is appropriate to keep the BSA and approve the EBSA for Pepco's MRP. The Commission approves Staff's recommended limitation of the EBSA to 10 percent of current rates. This is in keeping with recent previous rate case decisions, and provides for stability and gradualism throughout the MRP, and results in just and reasonable rates for all classes.

488. The record in this MRP application raises serious questions about the continued need, role, and structure of a BSA mechanism in a forward-looking rate proposal. While a BSA is intended to minimize different types and amounts of risk, when proposed rates are premised on forecasts, utilities should incorporate known changes into their forecasting to further minimize the level of risk exposure. For example, expected efficiency gains from approved programs should be incorporated into forecasts to minimize shifting risks to ratepayers.

489. In subsequent MRP filings, the Commission expects utilities to fully support the need for any BSA that will be effective during the rate-effective period, or remove the BSA altogether. The application should explain the intent and design of the BSA in the specific context of a forward-looking MRP. Further, the applicant should delineate specifically how the BSA and any risks of forecasting errors interact. Additionally, MRP applicants should provide a breakdown of what is responsible for any revenue under-recoveries over the previous three years, similar to the information Pepco provides in its annual reports to the District of Columbia Public Service Commission. Finally, any MRP application that uses a revenue adjustment mechanism, such as Pepco's effective BSA, when designing rates to maintain class revenue between forecast years shall include an

exhibit that compares the resulting revenues (in rate design) to the authorized revenues. This exhibit should explicitly show that the revenue adjustment mechanism (*e.g.,* BSA) is cost neutral and does not increase or decrease the MRP applicant's final revenue requirement after designing rates.

4. Rider ERR

490. Pepco witness Blazunas explained that, following the Rate Year 3, rates were designed to collect the Company's total proposed level of base distribution revenue, where the proposed customer and demand rate components are calculated using the same rate design methodology.[967] He noted that Rate Year 3 base distribution rates are partially offset by an approximately $54.237 million customer credit provided through Pepco's proposed Rider ERR, designed to mitigate the base distribution rate increases that would begin April 1, 2023.[968] Mr. Blazunas stated that the proposed Rider ERR would be in effect from April 1, 2023 through March 31, 2024 and the credits are applicable to each rate schedule's individual distribution rate components.[969]

491. AOBA witness Oliver opposed the use of Revenue Offsets and ERR Credits[970] He finds that the proposal shifts recovery to future periods.[971] Witness Oliver's preference is that the authorized increase is reduced "to ensure the affordability of Pepco's rates while minimizing or totally avoiding reliance on revenue offsets and/or Rider ERR Credits."[972] He argues that the premise for these measures which increase costs for future rate payers is "that Pepco customers in the periods beyond the Company's

[967] Blazunas Direct at 28.
[968] *Id.*
[969] *Id*. at 29.
[970] B. Oliver Direct, Part 1 at 21.
[971] *Id.* at 61.
[972] *Id.* at 61-62.

initial [MRP] will be more capable of bearing those costs," but he is concerned that this will not be true.[973]

492. Staff witness Hoppock recommended in surrebuttal that Pepco add language to Rider ERR stating when Pepco will file its annual update prior to rate year 2 consistent with the language approved for BGE's Rider 34.[974] Mr. Hoppock also recommended that Pepco be required to remove rate years 2 and 3 offsets from its Rider ERR until they are decided in the future consistent with Order 89678.[975]

<u>Commission Decision</u>

493. As the State emerges from the restrictions and subsequent economic impacts related to the COVID-19 pandemic, the Commission still finds value in offsetting any change to customer rates to minimize impacts to Maryland ratepayers during this time of transition. To be clear, Pepco has requested and the Commission is granting, in part, a rate increase. Similar to Order No. 89678 in BGE's MRP, the Commission finds that Pepco's current offset proposal is inconsistent with a major feature of a MRP, where rate changes are known and spread over multiple years.[976] The longer the rate offsets are in place the greater the rate impact will be in later years, coupled with uncertainty of any future true-ups and new rate proposals at the end of the MRP. The Commission supports the concept of the ERR rider but rejects it as structured to ensure the final yearly offsets comport with the Commission's goal of reexamining the need for offsets associated with rate increases each year of the MRP. Pepco shall refile its ERR rider with the

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[973] *Id.* at 63-64.
[974] *See* Hoppock Surrebuttal at 20.
[975] *Id.*
[976] Order No. 89678 at 200, para. 426.

Commission to comport with the direction given in this Order for the mitigating rate increases each year of the MRP.

494. New rates will be established at the beginning of each year with the revenues approved in this Order and the Commission directs the establishment of a new rider that will partially or fully offset the change in rates each year. At the beginning of each year, the rider will be revised such that the rider will fully or partially negate the change in rates depending upon how much of the rate increase the Commission determines will be avoided for the Rate Year.

495. For Rate Year 1, the Commission finds that the entire rate increase shall be avoided to ensure that customers' rates are not raised as Maryland begins to recover from the impacts of the COVID-19 pandemic. Pepco will be required to file updates to the rider 60 days before the end of Rate Year 1. The Commission will determine at that time the appropriate amount of customer funds that should be used to offset perceived changes, if any, in rates in Rate Year 2 and Rate Year 3 of the MRP.

496. The rider will be set for each rate class. The rider for each class will have a volumetric, demand, and customer charge component depending upon the classes' relevant charge components. The revenue refunded to customers through each charge component will be the difference in revenue between the rates in effect before the MRP, adjusted for BSA forecast where appropriate, and the new rates that result from this Order multiplied by the percentage offset directed by the Commission. The revenue for each charge component will be divided by the relevant billing determinants for the charge to set the rider refund for each charge component. Since the Commission has directed a 100 percent offset of new revenues in 2021, no charge experienced by a customer should

be different for Rate Year 1 than it is for current rates, except adjusted for the BSA forecast.

497. The Commission directs the rider to be listed separately on the customer's bill and be labeled, "Pepco MRP Rate Offset." Pepco may present the individual components of the rider as a single line item on the bill. This will increase transparency of the use of the customers' funds to offset Pepco's rate increase in Rate Year 1. The Commission finds that making the rider adjustment clear and transparent will keep customers informed about changes to their bill while simultaneously shielding them from experiencing a bill increase in the midst of recovering from the COVID-19 pandemic.

5. Other Rate Design Changes and Customer Bill Impacts

498. Pepco witness Blazunas stated that with regard to the Residential Service (Schedule R) rates, the customer charge will be flat for Rate Years 1 and 2 as there is no proposed overall base distribution revenue increase for the first two rate years.[977] He explained that for Rate Year 3, Pepco proposes an increase of $0.21, or 2.64 percent, to the customer charge, with a test period unit cost of $19.07 for Schedule R, and the increase resulting in a customer charge equal to 43.12 percent of the historical test period Unit Cost for Schedule R.[978]

499. According to Mr. Blazunas, for the Time Metered Residential Service Schedule, R-TM, Pepco similarly proposes no overall base distribution revenue increase Rate Years 1 and 2, a flat customer charge for those years, and the summer and winter volumetric rates adjusted to account for the EBSA while maintaining their existing relationship to

[977] Blazunas Direct at 30.
[978] *Id.*

one another.[979] He stated that for Rate Year 3, Pepco proposes an increase of $0.49, or 2.84 percent, to the customer charge, resulting in a customer charge equal to 80.10 percent of the historical test period Unit Cost for Schedule R-TM.[980]

500. Among the commercial rate designs, Mr. Blazunas stated that for the General Service Schedule, GS-LV, following flat customer charges for Rate Years 1 and 2, and the EBSA adjustment, Pepco proposes an increase of $0.34, or 2.84 percent, resulting in a customer charge equal to 47.37 percent of the historical test period Unit Cost for Schedule GS-LV.[981]

501. He stated that Pepco proposes adding a new rate schedule to its current group of four Servicing Street Lights ("SSL") rate schedules – titled "Servicing Smart LED Street Lights from Overhead Lines ("SSL-S-OH9 LED").[982] He stated further that with the addition of the new schedule, Pepco proposes to close the existing Schedule SSL-OH-LED (Servicing LED Street Lights from Overhead Lines) to new customers.[983] He noted that for the SSL class, as with the residential and other commercial classes, no overall base distribution revenue increase is proposed for Rate Years 1 and 2, therefore the per-lamp fixed and O&M charges are flat.[984] He added that for Rate Year 3, the rates included in the applicable schedules are adjusted uniformly to collect the proposed level of total distribution revenue, including the distribution revenue requirement increase.

502. Mr. Blazunas noted that the fixed charge for conventional street lights is adjusted so that no conventional street light has a lower fixed charge than a legacy LED street

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979 *Id*. at 31.
980 *Id.*
981 *Id*. at 31-32.
982 *Id*. at 40.
983 *Id.*
984 *Id.*

light, and the customer's maintenance charges for conventional street lights remain equalized with the O&M charges included in the Schedules for the legacy LED streetlight overhead and underground servicing schedules.[985] He added that the rates included in the proposed Schedule SSL-S-OH-LED are designed to remain flat for the duration of the MRP.[986]

503. According to AOBA witness Oliver, Pepco's use of revenue offset mechanisms amounts to a request for current authorization of rate increases that Maryland ratepayers would not experience until after the end of the proposed three-year MRP period.[987] In addition, he stated that the offsets will compound the rate increases following the initial MRP.[988] Witness Oliver further contended that Pepco's bill impact analyses are misleading in the assumption that customers in virtually all rate classes will see no bill increase in their monthly bills.[989] He stated that instead, those customers will see an increase in both Rate Years 1 and 2, and Maryland customers will experience additional automatic rate increases after the end of the proposed three-year MRP without any requirement for Commission approval.[990]

504. According to witness Oliver, Pepco's proposed automatic rate increases, occurring after March 31, 2024, would be compounded by Pepco's anticipated recovery of COVID-19 Regulatory Asset costs, the restart of Pepco's regulatory asset amortizations; the end of accelerated amortizations, the recovery of increased BSA deferred revenue balances, and other Pepco cost increases for ongoing operations and

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[985] *Id*.
[986] *Id*. at 41.
[987] B. Oliver Direct, Part 1 at 7.
[988] *Id*.
[989] *Id*.
[990] *Id*. at 8.

capital additions.[991] Witness Oliver recommended that the Commission not approve the use of the EBSA in the MRP.

505. Pepco witness Bonikowski provided an updated bill impact analysis for the MRP, explaining that under the proposed rates, a residential SOS customer using an average of 811 kWh per month will see a total monthly bill increase attributable to the proposed revenue requirement increase on average for each year of the MRP.[992] He provided detailed residential bill impact information indicating that the monthly increase would be $5.50 starting April 1, 2023 (or 4.31 percent of the total bill) and $5.50 as of April 1, 2024 (4.13 percent of the total bill).[993]

506. Mr. Bonikowski also provided changes to the proposed tariffs, noting that the "Terms of Service" for Schedule SSL-S-OH-LED were revised to correct the number of annual lighted hours, eliminate unnecessary or redundant terms, and incorporate additional clarifying language.[994] He added that the "Availability" section of Schedules SSL-OH and SSL-OH-LED were updated to reflect that, contingent on Commission approval of the proposed ED Streetlight Initiative, those schedules will be closed to new customers

507. Witness Bonikowski stated that Pepco has proposed an MRP Adjustment Rider in Schedule (MJB-R)-13 to credit imbalances that may occur between the Commission's approval of the revenue requirement as part of Pepco's initial rates and the actual revenue requirement filed as part of Pepco's Annual Informational Filings and/or Final

[991] *Id.*
[992] *See* Bonikowski Rebuttal at 29, Table 5.
[993] Bonikowski Rebuttal at 29
[994] *Id*. at 30.

Reconciliation to customers.[995] He explained that the Rider can credit an imbalance if the Commission deems it appropriate.[996] Mr. Bonikowski responded to AOBA witness B. Oliver's concerns with the MRP Adjustment Rider, as expressed in his rebuttal testimony.[997] Witness Bonikowski stated that witness B. Oliver's claim that any additional rider would impact Pepco's entire rate design presentation is without merit, because the MRP Adjustment Rider would adjust imbalances calculated as part of a future filing and has no impact on Pepco's rate designs as presented in this case.[998]

508. Staff witness Hoppock recommended that the Commission reject Pepco's proposed Target Revenue Adjustment to non-BSA tariff classes because of the substantial impact of the adjustment on certain classes and potential rate increases in the next MRP if the Streetlight Initiative is approved.[999]

509. Mr. Hoppock discussed the updated rate design that witness Bonikowski presented, with the requested revenue decreasing from $110 million to $104 million over the MRP, and Mr. Bonikowski increasing volumetric rates in Rate Years 1 and 2 based on the allocated revenue requirement for each class, while in Rate Year 3 increasing all rate components to meet the Rate Year 3 revenue requirement.[1000] Mr. Hoppock stated that in response to a Staff data request, Pepco provided a bill impact analysis based on current and proposed rates net of Rider ERR.[1001] Mr. Hoppock noted that he used Pepco's updated revenue requirement and his revised adjustment to billing determinant

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[995] *Id*. at 25.
[996] *Id.*
[997] *Id.*
[998] *Id*. at 26.
[999] Hoppock Surrebuttal at 7-8.
[1000] *Id.* at 8.
[1001] *Id.* at 12.

forecasts for Schedules R and RTM to update his proposed distribution rates, but his revenue allocation method and rate design methodology were unchanged.[1002]

510. Witness Hoppock stated further that he compiled bill impacts at his proposed rates, including the Rate Year 1 offsets,[1003] and bill impacts using witness Bonikowski's four-step allocation method, witness Patterson's revenue requirement and his updated adjusted billing determinants forecast and rate design methodology.[1004] In comparing the two impacts, Mr. Hoppock maintained his recommendation of his proposed revenue allocation method, stating that with Pepco's four-step method, the maximum volumetric rate increase would exceed 15 percent.[1005] He stated that his proposed rate design method better balances rate increases between volumetric and demand charges than the Pepco proposed rate design.[1006]

511. Witness Hoppock further recommended the following: (1) setting BSA revenue per month targets for each class based on the full Commission authorized revenue requirement for each class in each rate year, less any revenue offset; (2) requiring Pepco to add language regarding the option for customer ownership of street lighting equipment to the Schedule SSL10 S-OH-LED tariff; (3) rejecting Pepco's proposed Target Revenue Adjustment to non-BSA tariff classes; (4) that Pepco add language to Rider ERR stating when it is required to file its annual update prior to Rate Year 2, consistent with the

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[1002] *Id.* at 13-15; *see,* Ex. DH-6-SR.
[1003] Hoppock Surrebuttal at 17, Table 11.
[1004] *Id*. at 18, Table 12.
[1005] *Id.*
[1006] *Id*. at 19.

Commission's finalized language approved for BGE's Rider 34; and (5) requiring Pepco to remove Rate Years 2 and 3 offsets from its Rider ERR.[1007]

378. AOBA witness Oliver also expressed concerns with Pepco's bill impact analysis.[1008] He stated that while bill impact analyses are designed to be customer-focused and provide an understanding of how proposed rate changes will impact their monthly bills, Mr. Bonikowski indicates that Pepco's bill impact analyses instead are designed to isolate the impact of Pepco's revenue requirement.[1009]

512. He explained that the bill impact analyses only show the effects of Pepco's overall requested revenue requirement increases, but the EBSA's significant rate increase impact is hidden.[1010] Mr. Oliver stated that in Pepco's Schedule (MJB-R)-9, the EBSA adjustments to current rates mentioned are not separately shown, impeding the ability of the Commission and the parties to easily determine their impact.[1011]

513. Mr. Oliver asserted that, contrary to Mr. Bonikowski's testimony, Pepco's use of the EBSA is not consistent with prior bill impact analyses presented by Pepco and BGE.[1012] He cited Case No. 9472, which Mr. Bonikowski set forth as precedent for changing the bill impact analysis.[1013] According to Mr. Oliver, witness Blazunas' settlement testimony in Case No. 9472 did not contain any discussion of such changes to Pepco's bill impact analysis methodology.[1014] Witness Oliver added that Mr.

[1007] *Id.* at 50.
[1008] B. Oliver Surrebuttal at 39.
[1009] *Id.* at 40.
[1010] *Id.*
[1011] *Id.* at 43.
[1012] *Id.* at 41.
[1013] *Id.*
[1014] *Id.*

Bonikowski did not include any documents from Case No. 9472 to support his testimony about the precedent.[1015]

514. Witness Oliver recommended that the Commission require Pepco to present bill impact analyses that only reflect charges for Pepco's distribution services with no adjustments to Pepco's most recent Commission-approved rates.[1016] He maintained that the Commission should not allow adjustments to current charges for EBSA.[1017]

Commission Decision

515. The Commission does not take issue with the addition of a tariff summary page as it should assist with greater transparency. Pepco is directed to refile the tariff page to comport with the outcome of this Order. No rates or riders attributed to a customer class should be different from those previously approved by the Commission or explicitly approved in this Order.

516. Based on the adjustments made in this case in response to Pepco's MRP request, the Commission finds that the estimated effective per month bill impact – for a typical residential customer using 811 kWh per month during the MRP period – to increase zero dollars and zero percent in 2021, $3.66 (5.16 percent) in 2022, and $1.54 (2.05 percent) in 2023, as compared to the $5.50 increase (4.4 percent) in 2023 requested by Pepco.[1018]

[1015] *Id.*
[1016] *Id.* at 50.
[1017] *Id.*
[1018] *Compare*, Pepco Application at 4; McGowan Direct at 26.

	Table 12 Average Residential Bill Impact	
	$	%
2021	$ –	0.00%
2022	$3.66	5.16%
2023	$1.54	2.05%

E. Electric Vehicles

517. In Order No. 88997, in Case No. 9478, the Commission approved a Petition for Implementation of a Statewide Electric Vehicle Portfolio ("Petition") filed on behalf of the Public Conference 44 ("PC44") Electric Vehicle Working Group to create an Electric Vehicle ("EV") charging program.[1019] Pursuant to that Order, Pepco established an EV pilot program, including offerings for residential and multi-family customers, as well as publicly available utility-owned charging stations.[1020] Order No. 88997 allowed for cost recovery through regulatory asset accounting, which the utilities could amortize over a five-year period and place into rate base in a future rate case proceeding.[1021] Pepco's regulatory asset is included in this MRP filing as uncontested RMA 30.[1022]

518. As a condition for cost recovery, Order No. 88997 required utilities to provide benefit-cost assessments ("BCA") of their respective EV programs to obtain cost

[1019] Maillog No. 218613, Leader of PC44 Electric Vehicle Work Group, Petition for Implementation of a Statewide Electric Vehicle Portfolio (Jan. 22, 2018).
[1020] OPC Initial Brief at 67. *See also* McGowan Direct at 41.
[1021] Order No. 88997 at 75, 77.
[1022] Wolverton Direct at 40.

recovery in future rate cases.[1023] Pepco is seeking to recover EV program costs in this rate case. Pepco presented the Company's EV BCA in the testimony of witness Warner.

519. Witness Warner testified that overall his BCA analysis quantifies the physical impacts of Plug-In Electric Vehicle ("PEV") use, grid loading changes that result from vehicle charging, and net changes in emissions (from both the tailpipe and the power plant).[1024] He stated that these physical impacts are translated to economic consequences for three impacted populations—utility customers (ratepayers), PEV owner/operators, and society.[1025] Witness Warner combined his assessment of economic considerations into merit tests that quantify the net benefit-cost ratio from a variety of perspectives, including a portfolio level review, a market-wide societal cost test and detailed merit tests customized for each utility offering (*i.e.*, offer-specific tests).[1026]

520. Mr. Warner explained that "the market-wide test considers the PEV market overall, including Pepco programs as part of the ecosystem that supports PEV adoption and vehicle charging."[1027] He stated that a more narrow perspective can be gained by the offer-specific tests, which provide a preview of how Pepco investments benefit ratepayers compared with the costs—those incurred by the utility and other costs that might affect ratepayers.[1028] This two-part perspective allows for a market-wide view of the benefit/cost balance associated with vehicle electrification overall (including the utility

[1023] Order No. 88997 at 44 n.170.
[1024] Warner Direct at 4.
[1025] *Id.*
[1026] *Id.*
[1027] *Id.* at 5.
[1028] *Id.*

program investments), as well as a specific regulatory assessment of cost effectiveness from a ratepayer perspective.[1029]

521. Witness Warner provided the following chart to show the benefit-cost ratios for each of the perspectives discussed.

Table 13 **Merit Test Summary**				
Primary Case				
	B/C Ratio	Net Benefit NPV	Impacted Group	Impacts Considered
Portfolio Ratepayer Impact (Offerings 1-5)	1.09	$1,288,396	Ratepayers	Electricity Costs & Emissions
Market-Wide SCT (Natural)	1.98	$1,285,634,754	All	Electricity $, PEV OpEx, Emissions
Market-Wide SCT (Managed)	2.68	$1,634,801,692	All	Electricity $, PEV OpEx, Emissions
Offering 1: Residential Whole-House TOU	1.26	$53,267	Ratepayers	Electricity Costs Only (8-yr life)
Offering 2: Residential Smart L2 Off-Peak	1.51	$492,527	Ratepayers	Electricity Costs Only (8-yr life)
Offering 3: Residential TOU Pilot	0.33	-$206,762	Ratepayers	Electricity Costs Only (8-yr life)
Offering 4: Commercial Multi-family	1.02	$43,213	Ratepayers	Electricity Costs & Emissions
Offering 5: Public Charging (DCFC & L2)	1.09	$804,257	Ratepayers	Electricity Costs & Emissions

522. Mr. Warner testified that "[t]he portfolio view, which presents a composite view of net benefit across all the Company's offerings, ***provides a benefit/cost ratio of 1.09***, reflecting the beneficial impact of increased PEV adoption on both ratepayer costs and

[1029] *Id.*

the benefits of reduced emissions."[1030] He argued that the Societal Cost Test provides the best overall measure of net benefit, given the broad and transformative impact of vehicle electrification.[1031]

523. He testified that "[b]ased on a market-wide SCT that considers all costs and benefits, in the case where most residential charging happens in off-peak times (as encouraged by utility programs, *i.e.* the "Managed Charging" case), benefits exceed costs by a factor of 2.68."[1032] He noted further that in a more conservative case, in which charging is not shifted to off-peak times (*i.e.* the "Natural Charging case), "the market-wide benefits exceed costs by a factor of 1.98. The difference between the Managed and Natural charging cases quantifies the merit of the offerings being implemented by Pepco to shift vehicle charging loads to off-peak times."[1033]

524. Last, Mr. Warner shared that "[t]he offer-specific tests for Offerings 1, 2, 4, and 5 each demonstrate a benefit/cost ratio above 1.0 (1.26, 1.51, 1.02, and 1.09 respectively). Based on these collective outcomes, the Pepco EV charging program delivers an overall net benefit for utility ratepayers and other impacted sub-populations."[1034] He noted that while Pepco's residential EV-specific TOU pilot (Offering 3) delivers a benefit/cost ratio of 0.33, the Commission has already approved this pilot component, "and this outcome results from relatively small scale and key fixed costs associated with the pilot implementation."[1035]

[1030] *Id.*
[1031] *Id.* at 6.
[1032] *Id.*
[1033] *Id.*
[1034] *Id.*
[1035] *Id.*

525. Pepco commissioned the BCA study to provide a comprehensive and rigorous perspective on the costs and benefits associated with vehicle electrification in general and the proposed Pepco PEV charging offerings[1036] Mr. Warner testified that "the market-wide test considers the benefits of electrification overall, recognizing the impact of all PEVs on the road, and including the costs of the Company's EV programs to support charging infrastructure." He included PEVs beyond those directly impacted by the Company's programs as part of his overall benefit/cost assessment for two reasons:

> (a) to provide policy context for the value of vehicle electrification overall, which I believe is relevant to consideration of Pepco programs as part of that market (*i.e.* if electrification overall were not beneficial, then a utility program to support electrification would be of little merit), (b) to test whether the cost of the Pepco programs, when included as part of the broader market, disrupt the beneficial benefit/cost outcome for the market overall, and to (c) characterize the value of managed charging if it were to become dominant market-wide (compared with natural charging).[1037]

526. On the other hand, witness Warner noted that the offer-specific tests serve a different purpose—namely, to provide the utility and the Commission with insight into the benefits and costs that directly impact ratepayers.[1038] The offer-specific tests provide a preview of the ratepayer benefit/cost balance based on information available now, in the early stages of program deployment.[1039]

527. Witness Warner explained that the BCA analysis is based on a forecast of PEV adoption within Pepco's service territory covering 2020 through 2035.[1040] The forecast was recently updated to reflect the impact of COVID-19 on the EV market.[1041] The 15-

[1036] *Id.* at 7.
[1037] *Id.* at 8.
[1038] *Id.*
[1039] *Id.*
[1040] *Id.* at 9.
[1041] *Id.*

year forecast period was used as the basis for evaluation because it allows for calculation of "lifetime savings," as is typically included in net benefit-cost tests; it also d reflects the duration of Pepco's PEV charging programs and the typical PEV service life, which is assumed to be eight years based on a typical PEV warranty.[1042] Witness Warner also indicated that the forecast accounts for growth of the PEV fleet through new sales, as well as vehicle retirements and transfers of vehicles into and out of the state, covering both Battery Electric Vehicle (BEV) and Plug-in Hybrid Vehicle (PHEV) segments.[1043] To account for COVID-19 impacts, witness Warner testified that he "modified the original forecast in two ways: a) assumed a decline in 2020 sales compared with 2019 (about 21% lower), and b) modest growth in sales in 2021 (24% over 2020)."[1044]

528. The BCA quantifies physical impacts from PEV adoption by translating the number of PEVs on the road (from the forecast described above) into predominantly physical impacts on miles driven (gasoline versus electric), changes in electricity consumption (in megawatt hours (MWhs), changes in load profile (time-of-day MW distributions), and the resulting changes in emissions (net between tailpipe and power plant). These impacts are calculated for the baseline case (where there is no growth in PEV use), and the PEV adoption case under both "natural" and "managed" charging scenarios.[1045] Additionally, the physical impacts are further quantified in terms of their economic cost to impacted population sub-groups. The total cost for each of the three cases (baseline case with no PEV use growth, a PEV adoption case under natural charging, and a PEV adoption case under managed charging) are computed considering

[1042] *Id.*
[1043] *Id.*
[1044] *Id.* at 12-13.
[1045] *Id.* at 13.

the cost of electricity, operating expenses for vehicles, and the costs associated with emissions. If costs go down in the PEV case compared with the baseline, they are considered a benefit for the BCA calculation. If costs go up in the PEV case compared with the baseline, they are considered a cost for the BCA calculation.[1046]

529. Witness Warner testified that another key determination is how to quantify costs and benefits for utility customers due to changes in electricity costs. He noted that "those impacts are quantified through a comprehensive model that examines wholesale market impacts, implications for capacity and transmission costs, and impacts on the distribution revenues collected by the utility."[1047] He also pointed out that "the electricity cost impacts are applied differently in the market-wide test—which considers the impact of all PEVs on the road—and the offer-specific tests which generally consider only the impact of PEVs directly impacted by the Company's offers."[1048]

530. To quantify cost and benefits for PEV drivers, witness Warner testified that his analysis looked at the "impact on vehicle operating expense […] based on both the difference between fueling with electricity versus gasoline, combined with projected changes in maintenance expense."[1049] He observed that it costs less to "fuel" a PEV with electricity than it does to fuel a traditional vehicle with gasoline based on differences in vehicle efficiencies and basic energy costs (electricity versus gasoline).[1050] Furthermore, early market evidence suggests that PEVs cost less to maintain due to the simplified drive train. These two factors combined generate significant savings in operating expense for

[1046] *Id.* at 15.
[1047] *Id.* at 16.
[1048] *Id.*
[1049] *Id.* at 21.
[1050] *Id.*

PEV owners/operators.[1051] There are other costs and benefits that accrue to PEV drivers, including "a price premium for the initial vehicle purchase (a cost), and a one-time federal tax incentive associated with their new vehicle purchase (a benefit), and a variety of non-economic advantages."[1052]

531. OPC witness Lane argued that Pepco witness Warner has not shown that the EV Program is cost effective. Specifically, she argues that none of the three main components of Mr. Warner's BCA: (1) a portfolio-level BCA consisting of a Ratepayer Impact Measurement test; (2) a market-wide BCA using the Societal Cost Test; and (3) specific EV program offering tests "provide an accurate picture of the cost effectiveness of Pepco's EV pilot."[1053] Witness Lane argues against Mr. Warner's reliance on the ratepayer impact measurement test because the inclusion of impacts related to changes in utility revenues in those tests conflates rate impacts with cost-effectiveness."[1054] Further, witness Lane explained that ratepayer impact measurements serve a different purpose than the cost-effectiveness test. Ratepayer impact measurements "examine whether a utility investment or program will increase or decrease customer rates, and if so by how much." But a cost-effectiveness test "seeks to determine whether the benefits of a utility investment exceed the costs and therefore warrants investment on behalf of customers."[1055]

532. OPC witness Lane made clear that while witness Warner argues that his benefit-cost analysis "is helpful for understanding the overall policy merit of vehicle

[1051] *Id.*
[1052] *Id.* at 24.
[1053] OPC Initial Brief at 68.
[1054] *Id.*
[1055] *Id.*

electrification,"[1056] the pertinent question for the Commission is whether Pepco's investment in EV programs is beneficial or not.[1057] Therefore, she contends that "Pepco's BCA analysis should only include benefits and costs that are directly attributable to Pepco's EV program and not to the EV market as a whole."[1058]

533. Given the shortcomings that exist with witness Warner's EV BCA, OPC witness Lane recommended that the Commission disregard witness Warner's BCA and that it not be used to set precedent for future BCAs of EV programs conducted prospectively or retrospectively.[1059] Witness Lane recounted the Commission's directive in Case No. 9645 with regard to BGE's EV BCA—for the PC44 EV Work Group to develop a present to the Commission a consensus BCA methodology. This testimony raises many of the same issues identified in Case No. 9645; therefore, OPC witness Lane recommended that Pepco resubmit a BCA for each program offering at the end of the five-year pilot in accordance with the outcome of the EV Work Group process.[1060] She also suggested that the Commission:

> 1. Require Pepco to provide a justification of the costs related to Company-owned EV chargers as part of its consolidated reconciliation and final reconciliation as proposed in its [MRP] filing. This should include a summary of revenues received from Company-owned chargers, how revenues were returned to customers, and the cost of the program.
>
> 2. Require Pepco to conduct a rate and bill impacts analysis for each customer rate class at the end of the five-year pilot period to assess the overall ratepayer impacts from its portfolio of EV offerings. This analysis should account for actual revenues received from Company-owned chargers, the impact of increased distribution revenues from EV charging

[1056] Warner Direct at 25.
[1057] Lane Direct at 25.
[1058] *Id.*
[1059] *Id.* at 6.
[1060] *Id.*

due to the Company's programs, and how these revenues were allocated to each customer class.[1061]

534. Staff witness McAuliffe testified that Pepco witness Warner presented similar testimony and analysis in Case No. 9645. There, witness McAuliffe raised significant concerns with the BCA provided by witness Warner on behalf of BGE.[1062] Witness McAuliffe noted he would refrain from discussing Mr. Warner's BCA analysis for Pepco because of the concerns raised in Case No. 9645 wherein the Commission stated, "these concerns demonstrate the need for clarity and consistency on this issue."[1063] Witness McAuliffe deferred to the EV Work Group's future findings concerning a consensus BCA proposal but recommended that the Commission allow Pepco to move its EV costs into rates, subject to a future prudency review and ruling.[1064]

Commission Decision

535. While the Commission acknowledges Pepco's efforts to comply with Order No. 88997 and submit an EV benefit-cost analysis for its Pepco EV Pilot Program, the Commission finds that substantially similar, if not identical, issues about Pepco's benefit-cost analysis have been raised in this proceeding by Staff and OPC in Case No. 9645 for BGE. In that case, the Commission noted that Staff's and OPC's concerns "demonstrate[ed] the need for clarity and consistency on this issue."[1065] The Commission therefore found "it would be premature to impose greater structure based solely on the instant record, without the benefit of receiving input from other interested parties."[1066]

[1061] *Id.*
[1062] McAuliffe Direct at 57.
[1063] *Id.*
[1064] *Id.* at 58.
[1065] Order No. 89678 at 113.
[1066] *Id.*

The evidence in this case fails to lead to a different conclusion. Pepco also does not object to the Work Group process. Whereas the Commission previously directed the PC44 EV Work Group to develop and propose for our consideration a stakeholder-informed, consensus benefit-cost approach and methodology by December 1, 2021, the Commission finds no reason to deviate from that path.

536. As stated in Order No. 89678, the Work Group proposal should address, though it need not adopt, the concerns raised in this case and in Case No. 9645 as well as any other issues that may arise during the stakeholder process. The Commission further adopts by reference the specific requests articulated in Order No. 89678 that should inform the Work Group's efforts in preparing the proposal. The temporary stay of footnote 170 in Order No. 88997 shall remain in place until further notice. Lastly, the Commission will allow Pepco to move its uncontested EV costs into rates, subject to a prudency review at the conclusion of the MRP rate-effective period.

F. <u>Performance Incentive Mechanisms (PIMs)</u>

1. <u>Overview of Pepco's PIM Proposal</u>

537. Pepco witness Kevin McGowan testified that the Company "is proposing 'tracking only' PIMs be included as part of its [MRP]."[1067] He stated that the tracking only proposal will not include any financial implications during the MRP period.[1068] Mr. McGowan explained the Company is proposing "tracking only" PIMs for several reasons.

538. First, he noted that the development and application of PIMs is relatively new in Maryland, initiated only recently by the Commission through Order No. 89638 in

[1067] McGowan Direct at 28.
[1068] *Id.*

2019.[1069] Mr. McGowan explained that the tracking only PIM is a first step in the development of a full PIM program that would have financial incentives and penalties.[1070] Mr. McGowan contends that there is value in establishing a pilot process for PIMs without any financial implications or impact on revenue requirement and "allows the parties to focus on the process to establish and report on PIMs, rather than the design and application of the financial rewards and penalties."[1071] Still, Mr. McGowan testified that the Company fully "expects the PIMs proposed in this case to be fully developed over the [MRP] term and will become part of a PIM program, to include incentives and penalties in the next rate case."[1072]

539. Second, witness McGowan stated that Pepco wanted to advance more progressive PIMs that are different from the traditional operational metrics such as SAIFI or calls answered. To that end, Mr. McGowan noted that Pepco's proposed PIMs "do not have a robust history of data and trends as compared to more traditional operational metrics."[1073]

540. Third, witness McGowan argued that Pepco's MRP application covers the period April 1, 2021 through March 31, 2024, and the Company would not have another opportunity within the next three years to incorporate a full PIM program into a MRP, if the Commission does not approve a PIMs-related program in this MRP.[1074]

541. Finally, witness McGowan stated that Pepco's tracking only proposal will allow the parties and the Commission to gain experience with PIM development, tracking, and reporting, laying the groundwork for a more robust PIM program with penalties and

[1069] *Id.*, *citing* Order No. 89638 approving Performance Incentives Mechanisms in Case No. 9618.
[1070] McGowan Direct at 29.
[1071] *Id.*
[1072] *Id.*
[1073] *Id.*
[1074] *Id.*

rewards in the next MRP cycle.[1075] He noted that Pepco's tracking only PIMs are designed to be consistent with industry standards and supportive of the operational performance needs of Maryland and its customers.[1076]

542. In its present rate case application, Pepco proposed five tracking only PIMs across three broad category areas: reliability, customer service and environment. Pepco's proposed the following PIMs: reliability measures (Customer Average Interruption Duration Index, CAIDI, and Customers Experiencing Multiple Interruptions 4), customer service measures (First Call Resolution) and environmental-related measures (EV charger installation and greenhouse gas reductions). The specific PIMs metrics and targets proposed by the Company are addressed below.

2. CAIDI – Customer Average Interruption Index

Pepco

543. Pepco witness Robert S. Stewart offered testimony on the Company's proposed reliability PIMs. The first tracking only reliability PIM is CAIDI, which is expressed in minutes. Witness Stewart testified that in 2019, Pepco's CAIDI was 89 meaning the average Pepco customer experienced 89 minutes of interruptions (without IEEE[1077]-excluded events).[1078] Mr. Stewart argues that CAIDI is a more dynamic reliability measure than SAIFI or SAIDI.[1079] CAIDI is derived from dividing SAIDI by SAIFI; he

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[1075] *Id.*
[1076] *Id.* at 30.
[1077] Institute of Electrical and Electronics Engineers' (IEEE) excluded events are **major event days**, which are **defined** by **IEEE** Standard 1366, as a **day** in which the daily SAIDI exceeds a threshold value, TMED. ... Statistically, days having a daily system SAIDI greater than TMED are days when the energy delivery system experiences stresses beyond those normally expected—such as severe weather.
[1078] Stewart Direct at 12.
[1079] *Id.*

noted that improvements in CAIDI often require the utility to address issues that impact a small subset of customers.[1080]

544. Witness Stewart stated that Pepco currently reports on CAIDI as part of its Service Quality and Reliability Annual Performance Report; however, there are currently no performance targets or requirements in Maryland with respect to CAIDI.[1081] In his direct testimony, witness Stewart provided a chart that showed Pepco's CAIDI performance between 2015 and 2020 ranged from an average of 103 minutes of interruption (excluding IEEE excluded events) to 82 minutes of interruption (without IEEE excluded events).[1082] Witness Stewart stated that Pepco is proposing to track and report annually on CAIDI performance during the MRP, for evaluation at a later time for a PIM.[1083] Specifically, Pepco proposed the following metrics.

Table 14[1084]
CAIDI PIMs Metrics by Year

CAIDI PIM Metrics		**Upper/Lower Band**
2021	101.1	108.3 / 88.5
2022	101.1	108.3 / 88.5
2023	102.2	109.5 / 89.4

545. Witness Stewart argued that tracking the CAIDI metric would benefit customers by targeting reductions in areas where customers may experience longer restoration times

1080 *Id.*
1081 *Id.*
1082 *Id.* at 13.
1083 *Id.*
1084 *Id.* at 13, Table 2.

during a typical outage.[1085] Mr. Stewart also contends that tracking CAIDI "is a first step toward developing a formal PIM related to CAIDI in the future which would better align Pepco financial performance with its operational performance in a key Commission goal of reliability.[1086]

Staff

546. Staff witness Austin testified that Pepco's CAIDI should be rejected by the Commission and is not an appropriate PIMs metric since "COMAR 20.50.12.02D(1) already sets SAIDI and SAIFI targets that electric utilities are required to meet."[1087] Therefore, he surmised that by simply achieving its COMAR targets for SAIFI and SAIDI, a utility will automatically have a satisfactory CAIDI.[1088] Witness Austin pointed out that the CAIDI PIM targets Pepco proposes for each year of the MRP "will be easily surpassed if the Company meets its COMAR stipulated 2021 through 2023" SAIDI and SAIFI targets.[1089] Witness Austin explained that "[i]f the Company attains its exact COMAR 2021 through 2023 SAIDI and SAIFI targets, then its CAIDI from 2021 through 2023 will be 95.6, 95.6, and 96.6. Effectively the Company is proposing to be incentivized for simply meeting targets it is already required to meet as stipulated by COMAR." Additionally, witness Austin argued that Pepco's CAIDI is flawed as a PIM metric because mathematically "a utility can fail to meet either one or both of its COMAR stipulated SAIDI and SAIFI targets but still achieve a CAIDI target it sets for

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[1085] *Id*. at 14.
[1086] *Id.*
[1087] Austin Direct at 5.
[1088] *Id.*
[1089] *Id.*

itself."[1090] He noted that it is inappropriate to provide a performance incentive to Pepco for meeting a CAIDI target when the metric as designed also means that Pepco could fail to satisfy its SAIFI and SAIDI targets stipulated in COMAR.[1091]

OPC

547. OPC witness Whited testified that while she supports reporting both CAIDI and CEMI-4 metrics, Pepco already does this reporting as part of its Service Quality and Reliability Annual Performance Report, making additional reporting unnecessary.[1092] Rather than adopting additional CAIDI and CEMI4 metrics, witness Whited recommended "that Pepco augment its annual reliability report to include trends in both CAIDI and CEMI-4 so that the Commission and stakeholders can more readily discern whether performance is improving or deteriorating."[1093] In addition, witness Whited recommended that Pepco make CEMI performance data by neighborhood available for download through a link on its website so that stakeholders can understand where problem areas occur on Pepco's system and the steps Pepco is taking to address these issues.[1094] Regarding CAIDI, witness Whited testified that she does not believe that CAIDI provides a good indication of reliability and is concerned that Pepco's proposed reliability target would not encourage the utility to improve performance beyond what it already does.[1095] Specifically she pointed out that "an improvement in CAIDI could signal an increase in the frequency of outages, rather than any improvement in reliability. Conversely, if both SAIDI and SAIFI decline, but SAIDI declines proportionately less

[1090] *Id.*
[1091] *Id.* at 6.
[1092] Whited Direct at 21.
[1093] *Id.*
[1094] *Id.*
[1095] *Id.* at 23.

than SAIFI, then CAIDI will increase. In this case, worsening CAIDI would not necessarily imply a reliability problem, but rather that the frequency of outages was declining faster than the duration of outages."[1096]

548. In addition to these drawbacks, witness Whited testified that Pepco's proposed CAIDI and CEMI4 targets are not sufficient to drive changes in performance. Ms. Whited presented historical data showing that "[i]n three of the four most recent years, CAIDI has actually been below Pepco's proposed lower band of its target performance range."[1097] Similarly, witness Whited pointed out that "[s]ince 2016, Pepco has performed better than its proposed CEMI-4 target. In fact, Pepco's performance was superior to the lower band of its target performance range in years 2017 through 2020."[1098] Therefore, witness Whited argued that Pepco is proposing no improvements to its recent performance; rather, Pepco has set targets for itself that would allow its performance to significantly worsen while still meeting its targets.[1099]

549. OPC found even that Pepco is already subject to penalties for failure to meet reliability standards and therefore, the existing financial model already rewards Pepco for reliability investments. Witness Whited argued that Pepco failed to challenge itself to improve CAIDI and CEMI4 performance during the MRP period and recommended that the Commission reject Pepco's proposal for CAIDI and CEMI4 PIMs.[1100] Further, witness Whited commented that she would not support Pepco's proposed reliability PIMs of CAIDI and CEMI4 for two reasons: "1. Reliability is a core responsibility of the

[1096] *Id.* at 24.
[1097] *Id.*
[1098] *Id.* at 25.
[1099] *Id.* at 26.
[1100] *Id.* at 26-27.

utilities, and the utilities should not be provided with financial rewards for performing their key duties. 2. Pepco already earns a return on its capital investments and therefore already has a financial incentive to invest in its system."[1101]

AOBA

550. AOBA witness Bruce Oliver argued that Pepco's proposed CAIDI goals for 2021-2022 and for 2023 are set such that Pepco could expect to exceed the lower band (more favorable) level of performance with little or no incremental improvement from past CAIDI results and with little risk that the Company's performance would warrant assessment of a penalty.[1102] He stated that "[t]he Company's historic CAIDI results indicate that Pepco has exceeded the lower (most favorable) end of its proposed performance band in three of the last four years."[1103]

3. CEMI4 - Customers Experiencing Multiple Interruptions

Pepco

551. The second reliability PIM the Company proposes to track is CEMI, which stands for Customers Experiencing Multiple Interruptions.[1104] Witness Stewart noted that CEMI4 is defined as customers experiencing four or more interruptions over a 12-month period and is expressed as a percentage. He indicated that CEMI can be viewed as a measure of "neighborhood reliability" because it can be useful to identify small groupings of customers that are experiencing multiple outages in a given period.[1105] Mr. Stewart stated that Pepco currently reports CEMI as part of the Company's Service

[1101] *Id.* at 22.
[1102] B. Oliver Direct at 78.
[1103] *Id.* at 79.
[1104] Stewart Direct at 14.
[1105] *Id.*

Quality and Reliability Annual Performance Report, but there are currently no targets or requirements with respect to CEMI.[1106] Similar to CAIDI, Pepco is proposing to track and report annually on CEMI4 (based on IEEE exclusions) performance in Maryland during its MRP, for evaluation at a later time for a PIM. Specifically, Pepco proposed the following metrics and targets for CEMI during the MRP period:

Table 15[1107] CEMI-4 PIMs Metrics by Year		
CEMI-4 PIM Metrics		**Upper/Lower Band**
2021	2.5%	3% / 2.1%
2022	2.5%	3% / 2.1%
2023	2.5%	3% / 2.1%

552. Mr. Stewart noted that Pepco has implemented certain tools that address CEMI including a daily CEMI alerts flag when a customer has a second outage for the year, a CEMI dashboard, reporting and tracking of CEMI performance by neighborhood, and the establishment of a formal budgeted CEMI program.[1108] With all that is currently implemented for CEMI, witness Stewart nonetheless contends that tracking CEMI4 "is a first step toward developing a formal PIM related to CEMI in the future, which would better align Pepco's financial performance with its operational performance in a key Commission goal of neighborhood reliability."[1109]

[1106] *Id.*
[1107] Id at 13, Table 3
[1108] *Id*. at 16.
[1109] *Id.*

Staff

553. Staff witness Austin testified that he supports Pepco's CEMI4 metric as worthy of incentivizing. Witness Austin reasoned that this metric would force Pepco to focus on targeted improvements to those customers who experience four or more service interruptions in a calendar year and that this metric "supports the State's policy which according to PUA § 7-213(b), '[i]t is the goal of the State that each electric company provide its customers with high levels of service quality and reliability in a cost-effective manner, as measured by objective and verifiable standards...' "[1110] Witness Austin points out that Pepco's CEMI4 PIM metric is based on an IEEE standard which measures four or more interruptions in *any chosen one year period* and not the COMAR definition of CEMI which measures four or more interruptions *in a calendar year*.[1111] Witness Austin advises that should the Commission decide to accept CEMI as a metric then it would need to determine whether the targets should be based on the IEEE definition or the COMAR definition.

554. While Staff witness Austin supports CEMI as a PIM metric, he does not believe that the CEMI4 targets Pepco set for the MRP period are enough of a stretch challenge to the Company. Specifically, he argued that Pepco's proposed CEMI4 target of 2.5% with an upper band of 3.0% and a lower band of 2.1% would not be an appropriate target to incentivize.[1112] Mr. Austin pointed out that the Company's reported "CEMI4 (according to the IEEE definition) for the past five years (from 2015 to 2019) was 5.95%, 4.86%, 1.01%, 2.26%, and 2.44%. Therefore, since 2017, ratepayers have come to expect a

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[1110] Austin Direct at 6-7.
[1111] *Id*. at 7.
[1112] *Id.*

CEMI4 lower than 2.5%."[1113] He asserted that the whole idea of a PIM is not to reward performance that ratepayers have grown to expect as normal. Witness Austin stated that Pepco achieved a CEMI of 1.01% as defined by IEEE in 2017; therefore, he would support a CEMI4 target where the upper band is no greater than 1% as defined by IEEE for each year 2021 through 2023.[1114]

OPC

555. OPC witness Whited recommended that the Commission reject Pepco's proposed CEMI4 PIM and the related targets for the reasons stated above in the CAIDI section.

AOBA

556. AOBA witness Oliver questioned the value of Pepco's CEMI4 metric as a basis for a PIM. Witness Oliver stated that Pepco's CEMI4 metric includes no examination of results for specific neighborhoods or geographic subdivisions within Pepco's Maryland service territory.[1115] He further contends that "[s]imply computing the percentage of total customers that experience four or more service interruptions during a given time period reveals no information regarding neighborhood performance."[1116]

G. FCR - First Call Resolution

Pepco

557. Witness Bell-Izzard sponsored testimony to address Pepco's PIM focused on customer service – First Call Resolution (FCR).[1117] Witness Bell-Izzard defined the FCR as a measurement of customers' perception of their question being answered or their

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[1113] *Id.*
[1114] *Id.* at 8.
[1115] B. Oliver Direct at 80.
[1116] *Id.* at 81.
[1117] Bell-Izzard Direct at 20.

problem resolved in their first call to Pepco on that issue.[1118] Ms. Bell-Izzard testified that the FCR PIM would support the Company's overall goal to deliver premier customer service performance relative to its peers in the industry.[1119] She explained that Pepco views the FCR as a best practice in improving the Company's overall customer satisfaction and that the FCR is a new key performance indicator tracked by the Company. Ms. Bell-Izzard testified that Pepco "currently tracks FCR based on an automated analysis of the phone calls received by the call center."[1120] Under the current process, if the same phone number appears in the call center log twice within three days, the automated process determines that the issue was not resolved during the first call. Likewise, the first call is presumed resolved if the phone number does not appear twice within three days.[1121] She noted that Pepco resolved customers' questions on the first call around 80% of the time in 2020.[1122]

558. Witness Bell-Izzard testified that Pepco is proposing to change its process for determining the FCR metric from automated analysis to a survey question as part of the daily automated post-call survey process; customers will be asked whether their issue was resolved in the first call.[1123] Witness Bell-Izzard contends that "[u]sing a survey question where the customer can indicate whether they are calling a second time on the same issue, without a three-day limitation, will provide more accurate information on whether the Company resolved the call the first time."[1124] She noted that Pepco expects the FCR results to be lower using the survey method, compared to its current results of 80%

[1118] *Id.*
[1119] *Id.*
[1120] *Id.* at 22.
[1121] *Id.*
[1122] *Id.*
[1123] *Id.* at 21.
[1124] *Id.* at 22.

success, as calculated by the automated analysis. Therefore, Pepco has set the PIM target metric for the first two years of the MRP at 75% for 2021 and 2022, then at 80% in 2023 after evaluation of the survey results in the previous two years.[1125] Further, witness Bell-Izzard stated that Pepco proposes using a preliminary band of +/- 5% points to establish the upper and lower limits of the target range.

Staff

559. Staff witness Austin testified that he supports Pepco's FCR metric and that it is worthy of incentivizing. He noted that FCR was one of the three metrics that the Customer Communication Workgroup recommended should be tracked and reported as supplemental information in utilities' Annual Reliability Reports required each year, and the Commission approved the recommendation in its Order No. 89629 in Case 9353 on September 1, 2020.[1126] Witness Austin reasoned that this metric would lead Pepco to focus on improvements to call center operations that would enhance customer experience and drive customer satisfaction improvements.[1127]

560. While Staff witness Austin supported FCR as a PIM metric, he does not believe that the FCR targets Pepco set for the MRP period are enough of a stretch challenge to the Company. Pepco is proposing FCR targets of 75% for 2021 and 2022 and 80% for 2023 with a band of ±5% around those targets. Witness Austin pointed out that "for Pepco Maryland and Pepco DC, the FCR rate for 2019 was 76.28% and 79.62% for January through October, 2020."[1128] Consequently, witness Austin recommended that

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[1125] *Id.*
[1126] Austin Direct at 8.
[1127] *Id.*
[1128] *Id.* at 9.

the FCR target range should be no less than 85% for each year 2021 through 2023 as a reasonable target incentive.[1129]

OPC

561. Witness Whited testified that she finds "Pepco's proposed customer survey would provide additional information to help it better understand its call center performance and supports the proposal to track this information as long as it does not replace the automatic analysis currently used by Pepco in response to Order No. 89629." Witness Whited recommended that Pepco continue tracking FCR 2 using the automated methodology to help ensure there is not a worsening of performance relative to historical levels.[1130] Nonetheless, witness Whited does not believe that Pepco's FCR PIM is needed to encourage the Company to do more than it is already doing and stated that it is not clear that the benefits associated with the improved FCR program would be worth the costs.[1131] Additionally, witness Whited stated that "[a]ccording to recent survey results, 83 to 88 percent of issues are resolved in the first call, indicating that Pepco's proposed target of 75 percent for 2021 and 2022 is a low bar."[1132] Pepco's proposed target for the MRP does not encourage the Company to improve performance.[1133] Therefore, witness Whited recommended the Commission reject Pepco's request that FCR be made into a full PIM in the next base rate case.

[1129] *Id.*
[1130] Whited Direct at 28-29.
[1131] *Id.* at 29.
[1132] *Id.*
[1133] *Id.*

AOBA

562. AOBA witness Oliver testified that he did not find Pepco's rationale for its FCR PIM to be compelling. He argued that the FCR PIM "appears to provide no basis for independent assessment of what constitutes a 'resolved' contact with the Company's Call Center or Customer Service Agents."[1134] He also noted that the FCR metric treats all customer calls equally, which is an over-simplification of the customer service function.[1135] Finally, witness Oliver explained that data show Pepco achieved a FCR rate of 76.28% in 2019 and 79.62% for the first 10 months of 2020, which suggests that Pepco does not need further incentives to achieve the targeted levels of FCR performance.[1136]

1. **GHG – Greenhouse Gas Emission**

Pepco

563. Witness McGowan presented testimony supporting Pepco's proposed PIMs focused on the environment. First, witness McGowan stated that, as a corporate leader with significant facilities in the State of Maryland, the Company understands its critical role in addressing its carbon footprint and helping its customers and communities do the same.[1137] Pepco proposes to develop an annual GHG emissions target (reported as CO_2e in tons/year) for its total GHG over which it has direct operational control.[1138] Witness McGowan testified that "The Company has established an annual GHG target for Pepco of 41,974 metric tons/yr CO_2e for the calendar year 2020" (including both Maryland and

[1134] B. Oliver Direct at 82.
[1135] *Id.*
[1136] *Id.* at 83.
[1137] McGowan Direct at 35.
[1138] *Id.*

D.C. operations) with the Maryland operation representing approximately 52% of total Pepco emissions.[1139] In order to improve its emissions levels, witness McGowan stated that the Company planned for a 2% reduction in the GHG target levels each year. Specifically for its Maryland operations, Pepco's proposed GHG PIM target for each MRP year of 21,390 metric tons/yr CO2e for 2021, 20,962 for 2022, and 20,543 for 2023. The upper and lower bands were set at +/-10% because the Company has not historically tracked emissions separately by jurisdiction.[1140] Witness McGowan asserted that Pepco's GHG PIMs would support and advance the State's Greenhouse Gas Emissions Reduction Act – Reauthorization, which expanded the original law to require the State to achieve at least a 40% reduction in greenhouse gas emissions from 2006 levels by 2030.[1141]

Staff

564. Staff witness Austin testified that he supports Pepco's GHG metric and that it is worthy of incentivizing. Witness Austin noted that Pepco's GHG emissions PIM proposal uses a widely recognized metric of CO_2e (or carbon dioxide equivalent), which is a standard unit for measuring carbon footprints and is defined by the Environmental Protection Agency as the number of metric tons of CO2 emissions with the same global warming potential as one metric ton of another greenhouse gas.[1142]

565. While Staff witness Austin supported Pepco's use of GHG emissions as a PIM metric, he stated that he does not believe that the GHG emissions targets Pepco has set for the MRP are entirely appropriate. Witness Austin argued that he thinks the 2020

[1139] *Id.* at 36.
[1140] *Id.* at 36-37.
[1141] *Id.* at 38-39.
[1142] Austin Direct at 10.

CO_2e emissions forecast that Pepco uses as a baseline to set its targets is accurate.[1143] Witness Austin also testified that Pepco's 2 percent reduction in CO_2e emissions which it is targeting each year after 2020 is too conservative, but he concedes that it does become harder to find more sources of CO_2e emissions to cut. Consequently, witness Austin is willing to concede that Pepco's proposed 2% reduction in CO_2e emissions per year from the actual 2020 CO_2e emissions may be reasonable.[1144] Last, witness Austin noted that he believed that the upper limit of +10% over the GHG emissions targets could pose a "stretch challenge" for Pepco to achieve but, when taken into consideration with the argument that can be made that a 2% annual reduction in CO_2e emissions may already be too conservative, witness Austin did not find that getting within -10% of the targets to be enough of a "credible risk" of not achieving. Therefore, he recommended that a lower limit of -5% represents a more credible risk of the Company not achieving its GHG emissions targets to qualify for an incentive.[1145]

OPC

566. OPC witness Whited testified that while she can appreciate Pepco's GHG emissions PIMs proposal, "it is unclear what incremental benefit to customers this metric will provide, or that the targets in any way "accelerate the policy goal beyond the current utility's capabilities" as required by the Commission."[1146] Ms. Whited stated that according to her analysis, Pepco's emissions were lower than the proposed 2021 target in 2017, 2018, and 2020.[1147] Further, witness Whited noted that Pepco has already made

[1143] *Id.* at 12.
[1144] *Id.*
[1145] *Id.*
[1146] Whited Direct at 33.
[1147] *Id.* at 34.

significant progress in achieving GHG emissions reductions without an incentive.[1148] "It is not apparent that providing a financial incentive would provide any incremental benefit to ratepayers; rather it would likely reward Pepco for achieving results that it would have achieved anyway."[1149]

AOBA

567. AOBA witness Oliver opposed Pepco's GHG emissions PIM. He argued that Pepco offered no direct ties between the levels of GHG emission reductions that it should achieve and the expenditures (*e.g.*, purchases of EVs) that are already included in the budgeted MRP period costs.[1150] He also noted that Pepco did not provide any details regarding the GHG reductions it will be required to achieve under existing Maryland programs (*e.g.,* improvements in the energy efficiency of the buildings it operates and reductions in emissions from its vehicle fleet).[1151]

2. EV – Electric Vehicle Installation Acceleration

Pepco

568. Witness McGowan also presented testimony supporting Pepco's PIMs related to EV Charging Installations (EVCS). Mr. McGowan explained that Pepco's five-year EVCS program ends in June 2024, and the Company is committed to achieving 250 public charging station installations by the conclusion of the program.[1152] Witness McGowan asserted that because the deployment of EVCS is important to assist the State in meeting its Zero-Emission Electric Vehicle (ZEV) goal of 300,000 light-duty ZEVs on

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[1148] *Id.*
[1149] *Id.*
[1150] B. Oliver Direct at 74-75.
[1151] *Id.* at 75.
[1152] McGowan Direct at 33.

the road by 2025, Pepco believes that a PIM would encourage the Company to install additional EVCS in an accelerated manner.[1153]

569. The EVCS PIM relates to the cumulative number of public chargers Pepco installs each year of the MRP through the Company's public charging program.[1154] Specifically, witness McGowan laid out the targets for each MRP year in the table below:

Table 16[1155]
Number of Public EVCS Installations

Year	Threshold Annual	Threshold Cumulative (PIM)	Target Annual	Target Cumulative (PIM)	Stretch Annual	Stretch Cumulative (PIM)
2021	64	90	76	102	88	114
2022	64	154	76	178	88	202
2023	64	218	72	250	48	250
2024	32	250				

570. Witness McGowan points out that the proposed stretch target results in 250 public EVCS installations by June 2023, which is 12 months earlier than the existing EVCS deployment plan. Additionally, Mr. McGowan noted that this PIM allows Pepco to measure and monitor annual progress for the program and ensure resources are efficiently planned and allocated.[1156]

[1153] *Id.*
[1154] *Id.*
[1155] *Id.* at 34, Table 3.
[1156] *Id.* at 33.

Staff

571. Staff witness McAuliffe testified that he thought a PIM dedicated to EVs is appropriate but did not agree with Pepco's EVCS PIM. Witness McAuliffe explained that in Case No. 9478,[1157] the Commission granted Pepco permission to install 250 EVCS within the EV Pilot timeframe, so providing Pepco with a financial incentive to complete a task that is already expected is unnecessary. Further, witness McAuliffe argued that while Pepco has developed a PIM to install the 250 charges in a shorter timeframe than the original proposal, he does not believe that the EVCS PIM is ambitious enough or provides extra benefits to customers.[1158] Witness McAuliffe stated that "[a] PIM should only be awarded as a financial benefit if a company achieves a goal above and beyond normal practice."[1159] He disagreed that installing the chargers six months earlier than already expected is going above and beyond.

572. Witness McAuliffe noted that a "more appropriate PIM for Pepco's EV chargers would be the uptime [of] Pepco's publicly accessible chargers."[1160] He explained that a concern of EV drivers is whether the charging station which customers have chosen to use is fully operational, and one of the main reasons that utilities argued to be allowed to own and operate charging stations was a utility's ability to provide service in a reliable manner. Consequently, witness McAuliffe argued that the utilities should be held to the promise to have superior reliability at its charging stations.[1161] Witness McAuliffe pointed out that his alternate metric for EVs is a better PIM for two reasons: (1) it can be

[1157] McAuliffe Direct at 55.
[1158] *Id.*
[1159] *Id.*
[1160] *Id.*
[1161] *Id.* at 55-56.

measured after the pilot period ends; and (2) this PIM is currently tracked, allowing all parties to have ample data in which to develop the PIM target level. Additionally, Mr. McAuliffe asserted that "[t]his PIM would also require Pepco to continue to meet an ongoing reliability threshold instead of meeting a one-time goal such as installing chargers in a set time period."[1162]

OPC

573. OPC witness Whited testified that she was not opposed to Pepco tracking its EVCS installation performance but indicated the metric was redundant as Pepco already reports on the status of its public EVCS installations as part of its Semi-Annual Progress Report to the Commission.[1163] She noted that she supported continued tracking of the progress but thought establishing a new metric is unnecessary and would be moot by the next rate case since installation of the charges will be mostly complete by then.[1164]

574. Additionally, OPC witness Whited testified that "PIMs with financial incentives should only be applied where the utility has a disincentive to align its performance with the public interest." She explained that Pepco already has a strong incentive to install EVCS in a timely manner as it will earn a return on those assets in accordance with Order No. 88997 of Case No. 9478. Next, Ms. Whited noted that the proposed EVCS metric provides no indication of the benefits to customers associated with the target.[1165]

AOBA

575. AOBA witness Oliver testified that he believed there was very little value in Pepco's EVCS PIMS proposal. Specifically, witness Oliver commented that "[w]hether

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[1162] *Id.* at 56.
[1163] Whited Direct at 30.
[1164] *Id.* at 30-31.
[1165] *Id.* at 31.

Pepco is successful in accelerating its deployment of EVCS installations tells the Commission nothing about requirements for Pepco-initiated EVCS installations after the end of the proposed [MRP]."[1166] Witness Oliver also pointed out that "the value of earlier completion of planned EVCS installations must be questioned if the acceleration of those installations is achieved either at the expense of timely completion of other higher priority activities or at higher than budgeted costs."[1167] Additionally, Mr. Oliver stated that the Commission should question whether ratepayer subsidized EVCS installations are necessary and appropriate to achieve the State's environmental goals.[1168] Further, Mr. Oliver argued that it is not clear that Pepco's successful acceleration of its planned charging station installations during the proposed MRP will have any value as the basis for a future PIM.[1169]

3. Other PIM Proposals

OPC

576. OPC proposes several additional PIMs related to the deployment of non-wire alternatives ("NWAs") and customer empowerment. NWAs include a variety of demand side and grid side investments that defer or avoid the need for upgrades to the distribution system.

577. OPC witness Whited proposed that Pepco track the following metrics related to NWAs:[1170]

[1166] B. Oliver Direct at 77.
[1167] *Id.*
[1168] *Id.* at 78.
[1169] *Id.*
[1170] Whited Direct at 36.

1. Net savings from NWAs
2. NWAs capacity installed (MW)
3. NWA capacity (MW) by DER type
4. NWA request for proposals issued per year; and,
5. NWA customer participation (percent of customers by rate class).

578. OPC argued that tracking these five metrics related to NWAs would provide transparency and insight into Pepco's efforts to implement NWAs.

579. Second, OPC witness Whited recommended two tracking metrics to support customer empowerment that will provide customers with more information about their energy usage and increase customers' ability to manage that usage.[1171] Witness Whited's proposed metrics related to customer empowerment include:

1. Customer viewing Smart Energy Services content; and,
2. Customers with access to Green Button Connect My Data,

580. Witness Whited argued that these customer empowered metrics are good PIMs because Pepco currently has no incentive to increase their use.[1172] Pepco witness McGowan argued that the Commission should reject consideration of the proposed PIMs by other Parties because the Commission made clear in Order No. 89638 that only the utility may propose a PIM at this time.[1173]

Commission Decision

581. In Order No. 89638, the Commission found that "PIMs can serve as a valuable regulatory tool, with the potential to provide measurable benefits to both Maryland's

[1171] *Id.* at 38.
[1172] OPC Initial Brief at 60.
[1173] McGowan Rebuttal at 16.

ratepayers and utilities, while advancing State policies and interests."[1174] Nonetheless, the Commission expects any utility PIM proposal to meet four criteria, including that the PIM: (1) be tethered to a recognized State policy; (2) accelerate the policy goal beyond the current utility's capabilities; (3) show measurable benefits to ratepayers; and (4) contain metrics to track data trends over a specific timeframe.[1175]

582. In Order No. 89638, the Commission did not endorse any particular PIM option that had been presented in the Phase II Working Group Report. Rather, the Commission found that utilities have the most information about their business activities and capabilities and are in the best position to determine their ability to advance a particular State policy goal through a PIM.[1176] Moreover, the Commission held that "the utilities may propose any PIM that supports a State policy goal (including, but not exclusively, ratepayer benefits) *beyond historic baseline standards*."[1177]

583. Here, Pepco, proposed five tracking-*only* PIMs across three broad category areas: reliability, customer service and environment. While Pepco argued that its "tracking only" proposal will allow the parties to focus on the process to establish and report on PIMs, rather than the design and application of the financial rewards and penalties,"[1178] Witness McGowan testified that the Company fully "expects the PIMs proposed in this case to be fully developed over the [MRP] term and will become part of a PIM program, including incentives and penalties in the next rate case."[1179]

[1174] Order No. 89638 at 16.
[1175] *Id.*
[1176] *Id.* at 13.
[1177] *Id.* at 13 (emphasis added).
[1178] McGowan Direct at 29.
[1179] *Id.*

584. The Commission finds that Pepco, and any utility, may voluntarily track any potential PIM metric they deem valuable; however, if the utility expects those PIMs to become part of a program with financial rewards and penalties in a future rate case, then the PIMs must meet the criteria set forth in Order No. 89638. Here, the Commission finds that Pepco's five "tracking only" PIMs and their related targets fall disappointingly short of the mark. First, in three out of five of Pepco's proposed PIMs – the CAIDI, CEMI4 and FCR – various parties showed that the Company is already meeting, if not exceeding, the targets that it proposed for the MRP period. Therefore, the Commission finds that the Company's targets for CAIDI, CEMI4 and FCR fall short of the criteria in Order No. 89638 requiring that a PIMs proposal "*accelerate the policy goal beyond the current utility's capabilities.*"

585. The testimony in this record clearly shows that Pepco's proposed PIMs for CAIDI, CEMI4 and FCR are not stretch goals and would doubtfully accelerate the purported Company's performance beyond Pepco's current capabilities. With respect to Pepco's EVCS PIM proposal, the Commission finds that the Company has not shown sufficiently how any metric shortening the EVCS installations of 250 charging stations by six months would be of great benefit to the State and ratepayers beyond what is already required and expected to be achieved. Regarding GHG, OPC witness Whited testified that, according to her analysis, Pepco's current GHG emissions were lower than the proposed 2021 targets in 2017, 2018 and 2020. Additionally, OPC noted that Pepco is currently already exceeding its targets in reducing GHG emissions levels by 42 percent, from 2015 to 2019, and additional incentives are therefore unnecessary.[1180]

[1180] OPC Initial Brief at 58.

586. For these reasons, the Commission finds that Pepco is free to track any "tracking only" PIM "as foundation for potential future PIMs proposals" to be included in a future MRP. However, as noted by AOBA, Pepco does not require Commission approval to do so unless such tracking and reporting would require substantial additions to its historic test year levels of expenditures."[1181] As proposed, the Commission finds that Pepco's specific "tracking only" PIMs fall short of the criteria outlined in Order No. 89638 that PIMs must meet to become part of a rate case.

IV. **CONCLUSION**

587. In its Order Establishing a Multi-Year Rate Plan Pilot, the Commission found that by spreading forecasted rate changes over multiple years, MRPs could reduce the burden on rate case participants by staggering complex rate case applications over several years.[1182] In this case, the Commission finds forecasting by Pepco for its planned capital projects was challenging and that the Company's budget–to–spending history includes variances and fluctuations that do not allow for the confidence needed to approve all of the revenues requested.

588. While this Order does not constrain the execution of Pepco's capital construction projects, the Commission has not approved revenues to match all of Pepco's pending and planned projects. Ultimately, it will be up to Pepco to determine how to use the lower authorized revenue increase and how to allocate funds in a prudent manner to meet the reliability projections forecast in the Company's capital budget.

[1181] AOBA Initial Brief at 52.

[1182] Order No. 89482 at 1, 8 and 37. The Commission noted that the first utility to file a multi-year plan request, which happened to be Baltimore Gas and Electric Company ("BGE"), would be the test case for the pilot process. *Id.* at 10.

589. With regard to Pepco's LED Street Lighting Initiative, the Commission does not approve the proposal as rate base or revenue requirement components in this case. However, the Company may pursue this initiative in the Commission's EmPOWER Maryland docket, in a manner that meets the cost-benefit metrics for the EmPOWER program and incentivizes voluntary participation by the counties and municipalities.

590. Like BGE's MRP pilot application, Pepco's MRP application produced a number of challenges that the Commission and stakeholders will need to address in future proceedings. As the Commission noted in the MRP Pilot Order and reiterated in the BGE MRP Order, "In any rate case, stakeholders must have access to the data and methods relied on by a utility to develop and support its case."[1183] In a MRP case especially, access to information by all parties is vital to an effective and fair MRP.[1184]

591. Here again, asymmetries of information impeded the parties' ability to fully evaluate and respond to Pepco's proposal. While the MRP Pilot Order does not preclude the filing of a MRP proposal while another one is pending review, a utility MRP filing, at a minimum, should include searchable documents and spreadsheets that facilitate the ability of the parties to replicate analytics underlying the utility's proposals. Again, utilities filing MRPs should provide comprehensive stochastic forecasting information as part of the utility's case in chief, and utilities should also provide witness testimony regarding discrete forecasting generally and as it relates to capital projects in particular.

592. With regard to capital projects and spending, the MRP Pilot Order required project-level data for the first year of the MRP rate effective period, program-level data for each additional year of the MRP, and project-level data for large capital expenditures,

[1183] MRP Pilot Order at 17.
[1184] BGE MRP Order at 251-252.

regardless of the year for which the project is planned.[1185] Pepco's MRP application was filed before the Commission issued its BGE MRP Order but after the MRP Pilot Order. Nonetheless, Pepco's proposal suffered from many of the deficiencies that the Commission warned against in the BGE MRP Order.

593. Also, in the future, the Commission will expect MRP proposals to include robust project-level details sufficient to provide transparency into the utility's planning process for stakeholders and the Commission. Also, as instructed in the BGE MRP Order, proposed projects should be weighted in order of importance. Unlike BGE's MRP proposal, Pepco's application was not the pilot. Therefore, the Commission will not reiterate verbatim its instructions from the BGE MRP Order. However, until MRP regulations have been drafted and promulgated, the Commission expects compliance with those instructions in all future MRP proposals.

IT IS THEREFORE, this 28th of June, in the year Two Thousand Twenty-One, by the Public Service Commission of Maryland,

ORDERED: (1) That the Application of Potomac Electric Power Company, filed on October 26, 2020 (as supplemented by the Company over the course of this proceeding), seeking a multi-year plan requesting an increase in electric rates in the amount of $110 million, to be effective June 28, 2021 through April 1, 2024, as filed, is hereby denied;

[1185] MRP Pilot Order at 24.

(2) That, as directed in this Order, Pepco is hereby authorized to increase its Maryland electric distribution rates by no more than the amounts provided in Appendix A, labeled "Commission Approved Revenue Requirements."

(3) That Pepco is directed to accelerate the return of MASM and TCJA tax credits to ensure that there is no bill impact to customers during 2021, but it will not use accelerated offsets to prevent a bill impact in 2022, absent further direction from the Commission;

(4) That Pepco shall establish a rider that will partially or fully offset the change in rates each year that will be listed separately on customer bills and be labeled "Pepco Federal Tax Credit;"

(5) That Pepco's proposed Smart LED Street Lighting Initiative Program is rejected in this case, without prejudice to re-filing the proposal as an EmPOWER Maryland Program, as discussed in this Order;

(6) That Pepco is directed to file tariffs in compliance with this Order with the effective dates prescribed herein, subject to acceptance by the Commission; and

(7) That all motions or requests not granted herein are deemed denied.

/s/ Jason M. Stanek

/s/ Michael T. Richard

/s/ Anthony J. O'Donnell

Commissioners[1186]

[1186] Chairman Stanek and Commissioner Richard filed concurring statements, and Commissioners Linton and Herman filed dissenting opinions in this matter.

Concurring Statement of
Chairman Jason M. Stanek

I support the majority's decision to approve Pepco's MRP as modified in this Order, although in my view the utility's rate application only meets the minimum requirements. Pepco's initial filing was beset by a lack of sufficient detail, which required a labored undertaking by Commission Staff to obtain the information needed to complete their analysis. Notably, Commission Staff and AOBA identified serious deficiencies in Pepco's forecasted billing determinants and forecasting methodology, including its aggregation of multiple tariff classes into a single class model. Not only does this approach ignore the widely differing characteristics of the individual classes, it also compromises the accuracy of the forecast results.

When the Commission issued its 2019 guidance order on Alternative Forms of Rate Regulation, it determined that "the potential adoption of AFORs must be deliberative and carefully constructed."[1] The Commission has consistently held the view that asymmetries of information under MRPs are particularly problematic, and therefore reducing such asymmetries under MRPs is critical. Transparent forecast methodologies and accurate projected costs and billing determinants to set just and reasonable rates must be disclosed at the outset of a MRP application if a utility expects to experience the benefits associated with a multi-year rate plan. As such, every utility in Maryland would

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[1] Case No. 9618, *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company of Gas Company*, Order No. 89226 slip op. at 52 (Aug. 9, 2019).

do well to review this Order and the recommendations of Staff prior to filing any future MRP applications.

For these reasons, I concur.

/s/ Jason M. Stanek
Chairman Stanek

Concurring Statement of
<u>Commissioner Michael T. Richard</u>

While I am joining the decision to approve Pepco's MRP as modified by this Order, I am troubled by weaknesses identified in Pepco's forecasting and capital programs detailing Pepco's seeming resistance to accommodate data requests, and the overall timing that did not give the Company the ability to consider guidance from the Commission's decision in the BGE Pilot Order. I have concluded, however, that findings and decisions in this Order informed by recommendations from Commission Staff (particularly witnesses Hoppock and Li), OPC, and AOBA, will provide useful guidance for the development of future MRPs at this early stage. I echo the statement of Chairman Stanek that every utility in Maryland would do well to heed this Order prior to filing any future MRP applications.

I also want to highlight the Order's discussion about the purpose and benefits of Performance Incentive Mechanisms and my disappointment that Pepco's proposed "tracking only" PIMs fell so far short of the guidance and direction provided by this Commission in previous orders. The Commission found MRPs to be in the public interest partly because they work well in tandem with PIMs. Utilities have an ability to advance a number of important State policy objectives. Effective PIMs should be stretch-metrics beyond historic baseline standards and must provide measurable benefits for both utilities and ratepayers. Applicants should take a less isolationist approach and consider collaboration and consultation with stakeholders to aid in developing useful and actionable PIMs in future MRPs.

/s/ Michael T. Richard
Commissioner

Dissenting Statement of
Commissioner Odogwu Obi Linton

1. I respectfully dissent from the Majority Decision and, with the exception discussed below, concur with the Dissenting Statement of Commissioner Herman. Specifically, I would reject Pepco's Application as a "Pilot Utility" and instead, accept it as a standalone request to initiate a multi-year rate plan pursuant to the Commission's authority under PUA § 7-505. I write separately to explain my disagreement on that point.

2. The Commission established the MRP Pilot after nearly a year of interest, which included an effort, sponsored by several Maryland utilities (and without the support of the Commission), to lobby the Maryland General Assembly ("GA") during the 2019 Legislative Session to adopt legislation[1] that would create a framework for adopting Alternate Forms of Ratemaking in Maryland for all utilities. The Commission was not opposed to the concept of AFOR proceedings. Indeed, several have been adopted over the years. Instead, among other things, the Commission expressed concern over the structure of the proposed legislation and the speed at which it proposed to adopt AFOR proceedings for all companies.

3. The GA, in this Commissioner's opinion, correctly refused to adopt the utility's proposed legislative framework. This allowed the Commission the opportunity to establish a learning process, which would help inform the long-term structure of MRPs in Maryland. This included engaging in several unique steps, which when combined

[1] Senate Bill 572, House Bill 653, 2019 Maryland Legislative Session.

represent one of the most comprehensive learning efforts ever undertaken by the Commission. Specifically, the Commission established Public Conference 51 ("PC 51"), which accepted multiple informational and educational filings and culminated with the establishment of a two-day "learning conference", where multiple parties from various organizations, utilities and states with existing AFOR proceedings appeared in person to provide guidance and lessons learned on established AFOR procedures. Our Maryland utilities participated fully in those proceedings.

4. The Commission heard multiple comments from utility participants, interested stakeholders, and other guests—including representatives from other state utility regulatory commissions—at the conference about the benefits of an AFOR, for utilities and customers, and how there are challenges that encourage measured adoption. In response to those lessons, the Commission established a Working Group, in Order No. 89226, consisting of representatives of various stakeholders, all working together to recommend a series of principles that the Commission should incorporate into a future MRP initiative. Our Maryland utilities participated fully in those proceedings, too.

5. After receipt of the Working Group's Report, the Commission was *still* not ready to adopt a formal process for AFOR filings for all utilities. Accordingly, in Case No. 9618 (through Order No. 89482), on February 4, 2020, the Commission created a "pilot" program. Order No. 89482 was designed to give the Commission and interested parties additional experience which would culminate in a Rulemaking to formally establish Alternate Forms of Ratemaking in Maryland. Specifically, on page 2 of Order No. 89482, the Commission, stated:

> The Commission finds that undertaking a pilot will allow it to evaluate the use of MRPs in a controlled manner with minimal administrative burden and limited regulatory uncertainty for the initial utility seeking a Pilot MRP. After gaining valuable experience with implementing the Pilot MRP, the Commission will promulgate regulations to ensure the orderly consideration of MRPs statewide.
>
> This Order accepts, with modifications, the WG recommendations and establishes a Pilot for ***one utility***. The Commission finds that undertaking a pilot will allow it to evaluate the use of MRPs in a controlled manner with minimal administrative burden and limited regulatory uncertainty for the initial utility seeking a Pilot MRP. (emphasis added).

6. At page 10 of the same Order, the Commission noted that the Technical Staff also proposed, and supported the one utility "Pilot" approach: "The Staff proposals suggested that an initial MRP "Test Case" be filed by ***one utility and that no other utility could file an MRP until the completion of the three-year, rate-effective period and a "lessons learned" process***."[2] (emphasis added).

7. The Commission further stated its intention to design the MRP Pilot for **one** utility at page 12 of Order No. 89482. There, the Commission stated succinctly:

> As a result of this open process, the WG reached various levels of consensus on many items; however, the Commission believes additional experience and lessons learned will better inform our effort to adopt regulations. ***Accordingly, the Commission uses the Report as a starting point for forming a Pilot for one Maryland utility***. (emphasis added).

8. With that clarity expressed in the process as designed and adopted unanimously by the Commission in the Order, the Commission expected that the utilities, the initial parties that argued for adoption of AFORs, would support this measured, but forward moving approach. All indications at the time suggested we were correct and the industry understood the MRP Pilot design. In fact, BGE (an affiliate of Pepco) promptly filed a

[2] Order No. 89482, *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*, Case No. 9618, slip op. at 10 (Feb. 4, 2020).

letter, *the day after* Order No. 89482 was issued, volunteering to serve as our Pilot utility. Not surprisingly, BGE wrote: "BGE hereby expresses its willingness and desire to serve as ***the Pilot Utility consistent with the Commission's Order***." (emphasis added). As Maryland's largest utility, a combined gas and electric company, and one whose service territory is entirely within Maryland, BGE was an excellent Pilot utility choice. The Commission correctly accepted BGE's offer and the instant record reflects that to date, we have received ***no*** other letters or filings requesting participation in our Pilot.

9. So how did we get here? Perhaps a better question is: Why are we here? In the case before us, another Exelon company, Pepco, filed a request to participate in our Pilot MRP. As Commissioner Herman's dissent explains, the filing, which was neither invited nor encouraged, is lacking and ultimately does not, in the Dissent's opinion, rise to the level of a filing that meets the requirements of PUA § 7-505(c) for MRP treatment. Where I would disagree with the Majority is in the conclusion that the Company's filing cannot be rejected (or converted to an historic test year case) solely because it was filed as a "Pilot MRP" or that Order No. 89482 did not preclude additional MRP Pilot filings.

10. The "support" for the Majority's position can be most plainly found on pg. 13 of Order No. 84892. There, the Commission stated the following:

> However, the Commission does not have the statutory authority to require utilities to stagger their filings of MRPs or to prevent a utility from filing an MRP at any time. Thus, the filing of the initial MRP under this Pilot will not prohibit another utility from filing ***a rate case*** before the issuance of an order in the initial case. (emphasis added).

This language is not inconsistent with the Commission's creation of a Pilot MRP and direction to allow one utility to participate in the Pilot MRP. Here, the Commission clearly distinguished between a Pilot, or "initial MRP under this Pilot" filing and a rate case filing as authorized by statute ***within the same sentence.*** It makes clear that there is a difference between the two.

11. All utilities are, and always were, free to propose a standalone MRP at any time. This concept predates PC51 and is not in dispute.[3] Like the Commission has in other proceedings, that filing–if made–would have been evaluated on its merits and could have been treated as an HTY case if, as the Commission noted on pg. 13 of Order No. 84892, "the application is not "consistent with the public good" or the MRP "is not in the public interest" at the time it is filed. The record reflects that the Company agrees with this conclusion.[4] However, instead of filing its own stand alone MRP case, Pepco sought treatment as a "MRP Pilot utility", avoiding the more comprehensive filing that would have been necessary for a stand alone MRP filing and, in the process, creating multiple conflicts with the Commission's already established learning process.[5]

12. There is no record in this or any docket to support the Company's action. The Commission has not indicated anywhere that it wanted (or needed) two (*or more)* pilot utilities. Nowhere in the record is there supportive evidence to suggest the MRP Pilot design was deficient or lacking and that Pepco's filing identifies, and somehow fills those gaps. In fact, nowhere in Pepco's MRP Pilot filing does the Company suggest that BGE's Pilot filing was so deficient, that another Pilot MRP, from *another* company (specifically Pepco), was necessary to correct any perceived errors or omissions. As

[3] *See, e.g.,* Order No. 87857*, In the Matter of the Application of Sandpiper Energy, Inc. for a General Increase in its Natural Gas and Propane Rates*, Case No. 9410, 107 Md. P.S.C. 635 (2016) (authorizing Sandpiper to charge rates that automatically adjust every year in response to Sandpiper's actual mix of natural gas and propane customers).

[4] *See* Hr.g Tr. April 26, Vol. I at 141.

[5] For example, the Commission established certain deadlines in Order No. 89482 for final reports, establishing a rule making, and additional lessons learned procedures, all of which were recommended by the Working Group. Pepco's filing conflicts with these processes, since the filing will be pending while the Pilot MRP is concluded.

Commissioner Herman's Dissent succinctly notes, Pepco filed its MRP Pilot *before* the Commission even issued its decision in BGE's MRP Pilot case.

13. Accordingly, it is from here that I would begin a review of the instant MRP filing and, like Commissioner Herman, would find that it does not satisfy the requirements of the PUA for initiating an MRP. Pepco witnesses testified that the Commission has the authority to reject an MRP filing and convert it to a traditional historic test year case. Furthermore, multiple Pepco witnesses testified that the record exists in this case to take this approach. I would do so.

14. I believe this to be the necessary approach to take, and not solely because of the deficiencies in this case. The Commission, after much deliberation and effort to learn, chose the pilot approach as described in Order No. 89482. Peering into the future, should Pepco's sister utility Delmarva Power and Light choose to file a MRP "pilot" case too, all together approximately *85 percent* of all Marylanders would be receiving service from a utility participating in our MRP Pilot, which was designed and always intended for ***one company***; our technical staff would be facing the administrative burden of reviewing and monitoring ***three*** full and practically concurrently filed MRP filings a mere two years after the Commission received near unanimous guidance (except from the utilities) to proceed cautiously.[6]

15. Altogether, that sounds like a Statewide MRP to me, sans guidelines.[7]

[6] Commissioner O'Donnell accurately predicted this very situation during the Learning Conference. *See,* Learning Conference Day 2 PC51 Tr. at 448-453.

[7] By accepting Pepco as a MRP Pilot utility along with BGE, we must also face the possibility that the structure established in Order No. 89482 is no longer enforceable or viable under Maryland's Administrative Procedure Act.

16. This is neither the result we wanted nor what we designed. We should not lose sight of the guidance we received from our learned and experienced colleagues, the direction we told the GA we would take[8], and our own Orders and plainly stated intent to establish enforceable protections for customers ***before*** Maryland moved forward with AFOR's. We should stay the course.

17. Finally, I would defer to the Honorable Delores Kelley, Chairman of the General Assembly's Senate Finance Committee, who attended the Commission's Learning Conference on April 29, 2019, and delivered these words for the Commission's consideration:

> [W]e hope that this conference will move us closer toward a shared understanding of specific guardrails necessary for implementing any alternative rate regulation plans to be seriously considered given the particular facts and circumstances of each applicable Maryland utility.

18. For those reasons, I would reject Pepco's request to participate in the Order No. 89482 Pilot MRP and treat the application as a traditional historic test year filing. Accordingly, I dissent from the Majority Opinion and with the exception discussed herein, concur with the Dissent of Commissioner Herman.

/s/ Odogwu Obi Linton
Commissioner

[8] Representatives of the Maryland General Assembly attended the Commission's "Learning Conference" and offered comments for the Commission's consideration and edification.

Dissenting Statement of
Commissioner Mindy L. Herman

1. I respectfully dissent from the Majority Opinion in this proceeding on the grounds that the Applicant, Potomac Electric Power Company, failed to provide sufficient evidence that the requested $104 million rate increase over three years is just and reasonable. I would have denied the Company's Application in this case and attempted to set rates on the basis of a historic test year -- including the various adjustments consistent with prior Commission orders.[1]

A. Background of MRP Pilot Program

2. The Commission established Public Conference 51 ("PC 51") to review alternative ratemaking methods enabled by PUA §§ 4-102 and 7-505(c)(1). After the Commission received comments from interested parties and held a two day "learning conference" to receive advice from experts across the nation, the Commission held in Order No. 89226,[2] that the record in PC 51 supported the use of a multi-year rate plan and that a properly constructed and supported MRP could result in just and reasonable rates. In continuation of the Commission's efforts to establish a structured process for the filing of MRPs, the Commission established a Working Group of interested parties and charged the Working Group with developing and submitting a detailed

[1] Since I am not in the majority, I make no determination whether there is sufficient evidence on the record to enable a determination of rates based on a historic test year, allowing for inclusion of post-test year expenses in a manner consistent with Commission precedent.

[2] *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or a Gas Company*, Case No. 9618 (Order on Alternative Forms of Rate Regulation and Establishing Working Group Processes) (Aug. 9, 2019).

implementation report for the Commission's review of its process for furthering a MRP. That report was submitted to the Commission in Case No. 9618 on December 20, 2019.

3. In Order No. 89482 (the "MRP Pilot Order"),[3] the Commission discussed the results of the Working Group report and various comments filed by parties following specific directions provided by the Commission in Order No. 89226. The Working Group submitted an implementation report addressing numerous issues, including efforts by parties to obtain detailed information regarding distribution planning prior to the filing of a MRP. In the MRP Pilot Order, the Commission established a Multi-Year Rate Plan Pilot that provided a framework for a pilot program for a Maryland utility to file an MRP application.

4. On February 5, 2020, Baltimore Gas and Electric Company filed a response to Order 89482. In that letter, BGE Vice President and General Counsel John D. Corse, on behalf of the Company, expressed "its willingness and desire to serve as the pilot Utility consistent with the Commission's Order." Subsequently, on May 15, 2020, BGE was the first Maryland utility to file a MRP application.[4] Pepco, without a prior written statement as to its intention, filed its MRP on October 26, 2020, approximately two months prior to the Commission's issuance of the BGE MRP Order.[5]

5. In the MRP Pilot Order, the Commission found that, "establishing a pilot to consider the initial MRP pursuant to this Order will allow this first MRP filing to serve as

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[3] *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*, Case No. 9618, Order No 89482 (Order Establishing Multi-Year Rate Plan Pilot) (Feb. 4, 2020).

[4] I note that BGE and—the applicant here—Pepco are sister utilities that are part of Exelon Utilities, and therefore the Commission can assume that Pepco was aware that BGE was planning to be the first utility to file an MRP.

[5] The PUA requires the Commission to issue an order in a rate case order no later than 210 days after the utility files for new rates (PUA § 4-204); therefore Pepco was aware of the pending order issuance date for the BGE MRP Order.

an opportunity to gather valuable lessons learned."[6] The Commission then acknowledged that it does not have the statutory authority to require utilities to stagger MRP filings or to prevent a utility from filing a MRP at any time.[7] However, while recognizing its statutory limitation, the Commission specifically stated that it "may exercise its statutory authority to reject or modify a proposed MRP if it finds that the application is not 'consistent with the public good' or the MRP 'is not in the public interest' at the time it is filed."[8] As discussed above, a MRP must be properly constructed and supported.

6. In dissenting from the Majority Opinion, I do not reject the Pepco application on the grounds that it is not, by definition in the MRP Pilot Order, the "pilot utility." I accept that the Commission lacks the statutory authority to reject a rate filing on such grounds -- as discussed in the MRP Pilot Order. Rather, my rejection of Pepco's Application -- in this case -- is based on the lack of evidence submitted on the record and supported by witnesses in this proceeding, as discussed herein. I note, however, that Pepco did not wait until the BGE MRP rate order was issued before filing its application, and therefore could not have gained any insight into whether the BGE Pilot MRP resulted in any guidance regarding the filing of a future MRP.[9]

7. In my opinion, Pepco's decision to file its MRP prior to the issuance of an order in the BGE MRP case resulted in Pepco being unprepared for a MRP application based on the most recent Commission findings. For example, in the BGE MRP Order, the

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[6] MRP Pilot Order at 13.
[7] *Id.*
[8] *Id.*
[9] In its brief, Pepco states that it "closely monitored" the BGE MRP proceeding and worked with BGE to discover the types of questions being raised in discovery. Pepco Initial Brief at 9. While laudable, Pepco could not have known the Commission's reaction to the BGE application until release of the order on that proceeding, and thus was unable to address additional needs and guidance from the Commission before filing.

Commission cited a concern OPC raised in that case regarding proposed capital spending where historical budgets were doubled or tripled without explanation. The Commission also specifically stated that in future MRPs, "Utilities should provide a weighing of the importance of proposed capital, rather than a simple wish list untethered from ratepayer impact."[10]

8. In this case, Pepco failed to provide the weighing of proposed capital projects, even on rebuttal. In addition, as discussed below, Pepco did not adequately explain changes in forecasted costs for corrective maintenance or the 69kV feeder replacement program. Thus, I do not believe the Pepco application was sufficiently supported by evidence on the record.

9. In my opinion, the Pepco MRP application presented the Commission with less information and -- in some ways -- greater challenges than the BGE filing. Therefore in my opinion, Pepco's application was not a step forward in the development of the optimal MRP application as envisioned in the development of a MRP.[11]

B. <u>Burden of proof</u>

10. In Commission rate proceedings, the applicant must show by a preponderance of the evidence that the criteria in PUA § 4-201 are satisfied and that the proposed rates are just and reasonable.[12] The burden of proof is on the proponent of the rate change, here Pepco, to provide sufficient evidence to satisfy the statutory criteria for an increase in

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[10] Order No. 89678 at para. 537.

[11] I note that a great deal of testimony, time, and questioning at the hearing was devoted to Pepco's streetlight proposals and Performance Incentive Mechanisms. I do not disagree with the Majority's decision on the various streetlight proposals or PIMs, however, I note that the focus of the proceeding at times appeared to have been on the streetlights and PIMs, as opposed to the large, $104 million rate increase over a three-year period.

[12] *See, Coleman v. Anne Arundel County Police Department*, 369 Md. 108, 134-36, 797 A.2d. 770 (2002) (in Maryland administrative proceedings, the preponderance of the evidence standard is the evidentiary standard in contested cases.).

rates.[13] The PUA also specifies that Commission decisions must be supported by substantial evidence in the record.[14]

11. Pepco states that its workplans, which are the basis for its requested rate increase, were developed in a "thoughtful and deliberate manner, which is evidenced by the fact that budgets are consistent with Pepco's recent capital and operations and maintenance (O&M) spending levels . . . "[15] In developing a MRP, it is important not only whether budgets are consistent with *recent* spending levels, but also that forecasts in the past have been consistent with *actual* expenditures, thus tracking how well a company can forecast its spending levels. In a MRP, this is crucial evidence that enables the Commission to determine if the projected spending being requested is realistic and likely to be accurate.

12. At the evidentiary hearing, Mr. Barnett, the Company witness charged with explaining how Pepco's long-range plan is developed, did not have supporting evidence in the filed testimony before the Commission that showed how well Pepco's estimated budgets track to actual spending. Mr. Barnett stated that it was included in the pre-filed information.[16] He also stated that the budget information was accepted in Staff witness Patterson's testimony.[17] Reviewing Mr. Patterson's testimony on budgeting accuracy, on which Pepco appears to rely, Mr. Patterson merely states, "Pepco's filing requirements provide reports for budgets utilized for comparison of the historical test year, bridge year and [MRP] year 2022, 2023 and 2024. The data shows that Pepco's forecasts have been

[13] PUA § 3-112(b).
[14] PUA § 3-203.
[15] Pepco Initial Brief at 12.
[16] Hr'g Tr. at 184-85. Pursuant to long-standing Commission practice, pre-filed information is not included in the record unless offered and admitted at hearing and supported by accompanying testimony. *See* PUA § 3-111(b)(1).
[17] Hr'g Tr. at 194.

relatively close to actual results."[18] He further states, "The information I reviewed indicates Pepco's budget is a reasonable tool for setting rates in this proceeding as spending appears to be largely stable and consistent with historic spending."[19]

13. Again, while Mr. Patterson may have been convinced, it was incumbent on Pepco to prove to the Commission that its budgeted spending is a reasonable basis for forecasted rates, which it did not. There is no evidence to support these findings and on which Pepco could rely.[20]

14. PUA § 3-112(b) specifically requires that Commission orders be based on substantial evidence in the record. As discussed above, it is Pepco's burden to provide that evidence. Pepco attempted to remedy the lack of evidence on budgets by trying, without offering any supporting witness to attest to the veracity and accuracy of the information, to admit ***all*** of the prefiled materials into the record halfway through the hearing.[21] (That request was appropriately denied.)[22]

15. I strongly support any utility filing a MRP including in its application evidentiary support demonstrating that the utility has a good track record with respect to its forecasted spending. At least three years of historic program-level budgets compared to actual spend should be presented to the Commission.

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[18] Patterson Direct at 11.
[19] *Id.* at 12.
[20] Nor is it Mr. Patterson's role to prove Pepco's case. The fact that there is no evidence in the record to support Mr. Patterson's opinion is Pepco's failure, not Staff's.
[21] Hr'g Tr. at 276. It appears that Pepco agreed that the information regarding comparisons of budgeted spend to actual spend are not in the record by attempting, halfway through the hearing, to admit as evidence, "O&M capital forecast information, historical previous O&M and capital budgets and the like . . . ." *Id*.
[22] *In the Matter of Formal Complaint of New Frontiers Telecommunications, Inc. v. Verizon Maryland LLC*, Case No. 9452 (March 29, 2018) Proposed Order (affirmed by the Commission in Order No. 88793) (Aug. 16, 2018), 109 Md. PSC 597, 601 (2018).

16. I note that in the BGE MRP proceeding (Case No. 9645), Staff witness Vacarenghi provided charts attached to testimony showing BGE's track record of matching forecasted spending with actual spending. In his direct testimony, Mr. Valcarenghi provided an exhibit analyzing pre-filed data to show the history of BGE gas and electric O&M spending as compared to the forecasted spend for years 2017 – 2019.[23] Based on these exhibits, Mr. Valcarenghi concluded that BGE's O&M forecasts were stable and consistent with historic commitments.[24] While Mr. Patterson made similar conclusions that the forecasts were "relatively stable," he did not prepare comparable exhibits that the Commission could use to check whether it agrees that the forecasts are sufficient and stable.[25]

17. Staff witness Mr. Austin did raise several concerns, however, with Pepco's forecasted capital spending. He testified that forecasts for corrective maintenance were 28 percent higher than recently proposed in Case No. 9353 for the same time period as the MRP. He further testified that the 2023 corrective maintenance budget in this proceeding was 30 percent higher than forecasted in Case No. 9353.[26] These are significant differences for the same time periods. As discussed by the Majority, Mr. Austin also raised concerns with the unexplained spending increases in the 69kV Rebuild Program, as costs have increased from $428 million projected in Case No. 9602 (filed in

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[23] Ex. DMV 10-11 (Valcarenghi Direct).

[24] Valcanenghi Direct at 8-9.In addition to Staff's testimony in Case No. 9645, the Commission has an extensive knowledge of BGE's forecasting capabilities through its experiences with the STRIDE program under which the Commission for more than seven years has examined forecasted spending in comparison to actual spending.

[25] Again, this Dissent does not fault Mr. Patterson. It is not Staff's obligation or responsibility to make the case for a utility proponent.

[26] Hr'g Tr. 1085-86.

January 2019) to $650 million for the same projects in this proceeding.[27] Pepco's response that the budgets in Case No. 9353 were prepared in 2017 does little to persuade me that Pepco's forecasted budgets are reliable.

18. Similarly, I am concerned with Pepco's forecasted billing determinants.[28] There were numerous complaints from Staff witnesses, as well as other parties that the forecasted billing determinants were not easily understood until late in the proceeding. The Majority Opinion sets forth the difficulties that Staff and other parties had with respect to obtaining sufficient information to enable their review of the billing determinants forecast. While the Majority was able to overcome the issues raised in its opinion, I could not reach the same conclusion. For example, Staff witness Li stated in her direct testimony that, "the Company did not file with the Commission a separate and fully documented filing on its load forecasting," and that the "forecasting was not sufficiently documented as filed."[29] Staff witness Hoppock in his direct testimony stated that he could not have completed his analysis of the billing determinants forecast without the five-week extension that resulted from an error in the original application.[30] Pepco responded that it provided numerous data request responses, and that it held meetings with Staff to explain its forecasts. According to Pepco witness Effimova, Pepco provided an explanation of its forecasting methodology. In her rebuttal testimony Dr. Effimova provided as an exhibit the explanation provided to Staff, which consisted of a three and a

[27] Hr'g Tr. at 1087.

[28] My confidence in the Company's MRP request is eroded further by the fact that a significant error was found in Pepco's initially filed application that resulted in a five-week delay in the entire proceeding, as well as the numerous other corrections and errata in the record. .

[29] Li Direct at 22 and 35.

[30] Hoppock Direct at 12.

half page description.[31] Despite that brief explanation, Staff witness Li had a number of recommendations for future billing determinant forecasts, and Staff witness Hoppock proposed a cap on the Effective Bill Stabilization Adjustment (EBSA) to address Staff's ongoing concerns with Pepco's billing determinant forecasts. While I support the Majority's guidance regarding improvements in Pepco's billing determinant forecasting in future MRPs, I am not persuaded that Staff's and other parties' remedies sufficiently address the many serious concerns raised in this proceeding.

19. Based on the foregoing, I dissent from the Majority Opinion approving a MRP for Pepco on the grounds that the application was not sufficiently supported by evidence on the record, and therefore the resulting rates have not been demonstrated to be just and reasonable.

<u>/s/ Mindy L. Herman</u>
Commissioner

[31] Effimova Rebuttal Ex. EER-4.

Case No. 9655
Potomac Electric Power Company
Multi-Year Rate Plan
For the Years Ended March 31, 2022, 2023 and 2024

Awarded Revenue Requirement
(000s)

	Year 1	Year 2	Year 3
Adjusted Rate Base	$ 2,059,934	$ 2,182,649	$ 2,265,511
Rate Of Return	7.21%	7.21%	7.21%
Required Operating Income	$ 148,521	$ 157,369	$ 163,343
Adjusted Operating Income	$ 133,884	$ 131,205	$ 126,306
Operating Income Deficiency	$ 14,637	$ 26,164	$ 37,037
Conversion Factor	1.4106	1.4106	1.4106
Revenue Requirement	$ 20,647	$ 36,907	$ 52,244
Rate Base			
Unadjusted Rate Base	$ 2,380,668	$ 2,521,392	$ 2,691,862
Uncontested Adjustments	(287,693)	(187,253)	(188,202)
Remove Smart LED Program Costs	(745)	(883)	(545)
Reflect Establishment of COVID Regulatory Asset	1,073	835	597
Remove Contingencies	(6,351)	(11,613)	(14,244)
Remove Unsupported Capex Spending	(27,018)	(139,829)	(223,957)
Adjusted Rate Base	$ 2,059,934	$ 2,182,649	$ 2,265,511
Operating Income			
Unadjusted Operating Income	$ 148,464	$ 135,810	$ 130,219
Uncontested Adjustments	(15,601)	(7,676)	(8,724)
Remove Smart LED program Costs	79	(70)	(164)
Adjust Baseline Distribution Revenues	724	527	595
Reflect Establishment of COVID Regulatory Asset	(404)	(404)	(404)
Adjust Property Tax Based on Uncertain Capex Spend	285	1,287	2,024
Adjust Depreciation Exp Based on Unsupported Capex Spend	618	2,790	4,388
Interest Synchronization	(282)	(1,059)	(1,627)
Adjusted Operating Income	$ 133,884	$ 131,205	$ 126,306

Appendix B
Staff Comparison Chart

Case No. 9655
Potomac Electric Power Company
12 month ending March 31, 2022
Revenue Requirement Comparison
(Thousands of Dollars)

		Pepco (Rebuttal)				Staff (Surrebuttal)				OPC (Surrebuttal)				AOBA (Surrebuttal)				
Conversion		1.4109				1.4106				1.4109				1.4109				
ROR		7.54%	Rate Base	Operating Income	Revenue Requirement	7.14%	Rate Base	Operating Income	Revenue Requirement	6.93%	Rate Base	Operating Income	Revenue Requirement	6.92%	Rate Base	Operating Income		Revenue Requirement
	Unadjusted																	
	Plant in Service		4,197,831															
	Construction Work in Progress		277,200															
	Plant Held For Future Use		9,422															
	Accumulated Depreciation		(1,553,500)															
	Accumulated Amortization		(30,135)															
	Materials and Supplies		50,294															
	Cash Working Capital		20,176															
	Accumulated Deferred Income Taxes		(687,061)															
	Prepaid Pension/OPEB Liab.		95,177															
	Customer Deposits		(44,631)															
	Pepco Portion of Servco Assets		17,722															
	Regulatory Assets		28,039															
	Unamortized Credit Facility Costs		135															
	Total Unadjusted		2,380,668	148,464	$ 43,792		2,380,668	148,464	$ 30,350		2,380,668	148,464	$ 23,333	**2/**	2,290,744	149,681		$ 12,583
	Uncontested Adjustments		(287,693)	(15,601)	$ (8,594)		(287,693)	(15,601)	$ (6,969)		(287,693)	(15,601)	$ (6,121)					
RMA	**Contested / Adjusted Adjustments**																	
31	Reflection of establishment of Reg Asset for COVID-19 Related Costs		2,136	(475)	$ 897		1,073	(404)	$ 678		1,074	(475)	$ 775		-	-		$ -
33	Reflection of Revenue Requirement Offsets on Rate Base		7,655		$ 814		-		$ -		1,592		$ 156		-			$ -
36	Interest Synchronization			(373)	$ 526			(609)	$ 859			(1,030)	$ 1,453					
1/	Adjust Capital Additions				$ -		(20,733)		$ (2,088)		(92,933)		$ (9,088)		(20,733)			$ (2,025)
	Adjust Contingencies				$ -		(6,351)		$ (640)				$ -					$ -
1/	Adjust Depreciation Expense - Capital Additions				$ -			384	$ (542)			1,688	$ (2,382)			384		$ (542)
	Adjust Depreciation Expense - Contingencies				$ -			118	$ (166)				$ -					$ -
	Adjust Property Tax Expense				$ -			231	$ (326)			787	$ (1,110)					$ -
	Adjust Baseline Distribution Revenues Schedules R and RTM				$ -			724	$ (1,021)				$ -					$ -
	Adjust Vegetation Management Costs				$ -			381	$ (537)				$ -					$ -
	Adjust Wages and Salaries				$ -				$ -			906	$ (1,278)					$ -
	Total - Cumulative		$ 2,102,766	$ 132,014	$ 37,437		$ 2,066,965	$ 133,689	$ 19,596		$ 2,002,708	$ 134,737	$ 5,740		$ 2,270,011	$ 150,065	**3/**	$ 10,016
	Revenue Requirement Offset				$ (37,437)				$ (19,596)				$ (5,740)					

Capital Structure	Ratio	Cost	Wt'd Return	Ratio	Cost	Wt'd Return	Ratio	Cost	Wt'd Return	Ratio	Cost	Wt'd Return
Long-Term Debt	49.50%	4.82%	2.39%	49.50%	4.82%	2.39%	49.50%	4.82%	2.39%	49.50%	4.55%	2.25%
Common Equity	50.50%	10.20%	5.15%	50.50%	9.40%	4.75%	50.50%	9.00%	4.55%	50.50%	9.25%	4.67%
Rate of Return	100.00%		7.54%	100.00%		7.14%	100.00%		6.93%	100.00%		6.92%

Notes:
1/ AOBA Supports Staff's Adjustment to Capital Additions and Staff's Adjustment to Depreciation Expense- Capital Additions.
2/ AOBA's Rate Base and Operating income are based on Schedule (TBO)-6 Revised 4/20/2021 and adjusted to reflect Staff's Capital Additions Adjustment.
3/ AOBA recommends that the Commission should evenly spread AOBA's proposed Year 3 cumulative revenue requirement over each rate year of the proposed MYP Period, $18,246.33.

Appendix B
Staff Comparison Chart

Case No. 9655
Potomac Electric Power Company
12 month ending March 31, 2023
Revenue Requirement Comparison
(Thousands of Dollars)

		Pepco (Rebuttal)				**Staff (Surrebuttal)**				**OPC (Surrebuttal)**				**AOBA (Surrebuttal)**			
Conversion		1.4109				1.4106				1.4109				1.4109			
ROR		7.54%	Rate Base	Operating Income	Revenue Requirement	7.14%	Rate Base	Operating Income	Revenue Requirement	6.93%	Rate Base	Operating Income	Revenue Requirement	6.84%	Rate Base	Operating Income	Revenue Requirement
	Unadjusted																
	Plant in Service		4,546,422														
	Construction Work in Progress		174,292														
	Plant Held For Future Use		9,422														
	Accumulated Depreciation		(1,628,651)														
	Accumulated Amortization		(42,669)														
	Materials and Supplies		50,294														
	Cash Working Capital		21,125														
	Accumulated Deferred Income Taxes		(703,229)														
	Prepaid Pension/OPEB Liab.		105,298														
	Customer Deposits		(44,631)														
	Pepco Portion of Servco Assets		13,003														
	Regulatory Assets		20,663														
	Unamortized Credit Facility Costs		54														
	Total Unadjusted		2,521,392	135,810	$ 76,616		2,521,392	135,810	$ 62,373		2,521,392	135,810	$ 54,948	2/	2,447,408	138,986	$ 40,071
	Uncontested Adjustments		(187,253)	(7,676)	$ (9,090)		(187,253)	(7,676)	$ (8,032)		(187,253)	(7,676)	$ (7,481)				
RMA	**Contested / Adjusted Adjustments**																
31	Reflection of establishment of Reg Asset for COVID-19 Related Costs		1,661	(475)	$ 847		835	(404)	$ 654		835	(475)	$ 752		-	-	$ -
33	Reflection of Revenue Requirement Offsets on Rate Base		41,674		$ 4,433		-		$ -		3,401		$ 333		-		$ -
36	Interest Synchronization			(49)	$ 69			(697)	$ 983			(1,794)	$ 2,531				
1/	Adjust Capital Additions				$ -		(44,512)		$ (4,483)		(226,695)		$ (22,168)		(44,512)		$ (4,295)
	Adjust Contingencies				$ -		(11,613)		$ (1,170)				$ -				$ -
1/	Adjust Depreciation Expense - Capital Additions				$ -			825	$ (1,164)			4,135	$ (5,834)			825	$ (1,164)
	Adjust Depreciation Expense - Contingencies				$ -			215	$ (303)				$ -				$ -
	Adjust Property Tax Expense				$ -			480	$ (677)			1,927	$ (2,719)				$ -
	Adjust Baseline Distribution Revenues Schedules R and RTM				$ -			527	$ (743)				$ -				$ -
	Adjust Vegetation Management Costs				$ -			381	$ (537)				$ -				$ -
	Adjust Wages and Salaries				$ -				$ -			763	$ (1,077)				$ -
	Total - Cumulative		$ 2,377,473	$ 127,610	$ 72,873		$ 2,278,851	$ 129,460	$ 46,902		$ 2,111,679	$ 132,690	$ 19,284		$ 2,402,896	$ 139,811 3/	$ 34,611
	Revenue Requirement Offset				$ (72,873)												

Capital Structure	Ratio	Cost	Wt'd Return	Ratio	Cost	Wt'd Return	Ratio	Cost	Wt'd Return	Ratio	Cost	Wt'd Return
Long-Term Debt	49.50%	4.82%	2.39%	49.50%	4.82%	2.39%	49.50%	4.82%	2.39%	49.50%	4.38%	2.17%
Common Equity	50.50%	10.20%	5.15%	50.50%	9.40%	4.75%	50.50%	9.00%	4.55%	50.50%	9.25%	4.67%
Rate of Return	100.00%		7.54%	100.00%		7.14%	100.00%		6.93%	100.00%		6.84%

Notes:
1/ AOBA Supports Staff's Adjustment to Capital Additions and Staff's Adjustment to Depreciation Expense- Capital Additions.
2/ AOBA's Rate Base and Operating income are based on Schedule (TBO)-6 Revised 4/20/2021 and adjusted to reflect Staff's Capital Additions Adjustment.
3/ AOBA recommends that the Commission should evenly spread AOBA's proposed Year 3 cumulative revenue requirement over each rate year of the proposed MYP Period, $18,246.33.

Appendix B
Staff Comparison Chart

Case No. 9655
Potomac Electric Power Company
12 month ending March 31, 2024
Revenue Requirement Comparison
(Thousands of Dollars)

		Pepco (Rebuttal)				Staff (Surrebuttal)				OPC (Surrebuttal)				AOBA (Surrebuttal)			
Conversion		1.4109				1.4106				1.4109				1.4109			
ROR		7.54%	Rate Base	Operating Income	Revenue Requirement	7.14%	Rate Base	Operating Income	Revenue Requirement	6.93%	Rate Base	Operating Income	Revenue Requirement	6.76%	Rate Base	Operating Income	Revenue Requirement
	Unadjusted																
	Plant in Service		4,835,091														
	Construction Work in Progress		170,308														
	Plant Held For Future Use		9,422														
	Accumulated Depreciation		(1,712,698)														
	Accumulated Amortization		(57,610)														
	Materials and Supplies		50,294														
	Cash Working Capital		21,812														
	Accumulated Deferred Income Taxes		(721,399)														
	Prepaid Pension/OPEB Liab.		116,513														
	Customer Deposits		(44,631)														
	Pepco Portion of Servco Assets		10,532														
	Regulatory Assets		14,218														
	Unamortized Credit Facility Costs		10														
	Total Unadjusted		2,691,862	130,219	$ 102,639		2,691,862	130,219	$ 87,429		2,691,862	130,219	$ 79,506	2/	2,636,592	132,363	$ 64,540
	Uncontested Adjustments		(188,202)	(8,724)	$ (7,713)		(188,202)	(8,724)	$ (6,649)		(188,202)	(8,724)	$ (6,095)				
RMA	**Contested / Adjusted Adjustments**																
31	Reflection of establishment of Reg Asset for COVID-19 Related Costs		1,187	(475)	$ 796		597	(404)	$ 630		597	(475)	$ 729		-	-	$ -
33	Reflection of Revenue Requirement Offsets on Rate Base		80,756		$ 8,591		-		$ -		3,401		$ 333		-		$ -
36	Interest Synchronization			178	$ (251)			(982)	$ 1,385			(2,474)	$ 3,491				$ -
1/	Adjust Capital Additions				$ -		(80,696)		$ (8,127)		(326,063)		$ (31,885)		(80,696)		$ (7,691)
	Adjust Contingencies				$ -		(14,244)		$ (1,435)				$ -				$ -
1/	Adjust Depreciation Expense - Capital Additions				$ -			1,496	$ (2,110)			6,020	$ (8,494)			1,496	$ (2,111)
	Adjust Depreciation Expense - Contingencies				$ -			264	$ (372)				$ -				$ -
	Adjust Property Tax Expense				$ -			812	$ (1,145)			2,805	$ (3,958)				$ -
	Adjust Baseline Distribution Revenues Schedules R and RTM				$ -			595	$ (839)				$ -				$ -
	Adjust Vegetation Management Costs				$ -			-	$ -				$ -				$ -
	Adjust Wages and Salaries				$ -				$ -			660	$ (931)				$ -
	Total - Cumulative		$ 2,585,603	$ 121,198	$ 104,059		$ 2,409,317	$ 123,276	$ 68,765		$ 2,181,595	$ 128,031	$ 32,695		$ 2,555,896	$ 133,859	3/ $ 54,739
	Revenue Requirement Offset				$ (51,847)												

Capital Structure	Ratio	Cost	Wt'd Return	Ratio	Cost	Wt'd Return	Ratio	Cost	Wt'd Return	Ratio	Cost	Wt'd Return
Long-Term Debt	49.50%	4.82%	2.39%	49.50%	4.82%	2.39%	49.50%	4.82%	2.39%	49.50%	4.21%	2.08%
Common Equity	50.50%	10.20%	5.15%	50.50%	9.40%	4.75%	50.50%	9.00%	4.55%	50.50%	9.25%	4.67%
Rate of Return	100.00%		7.54%	100.00%		7.14%	100.00%		6.93%	100.00%		6.76%

Notes:
1/ AOBA Supports Staff's Adjustment to Capital Additions and Staff's Adjustment to Depreciation Expense- Capital Additions.
2/ AOBA's Rate Base and Operating income are based on Schedule (TBO)-6 Revised 4/20/2021 and adjusted to reflect Staff's Capital Additions Adjustment.
3/ AOBA recommends that the Commission should evenly spread AOBA's proposed Year 3 cumulative revenue requirement over each rate year of the proposed MYP Period, $18,246.33.