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ORDER NO. 89678

Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan	* * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9645

ORDER ON PILOT APPLICATION FOR A 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: December 16, 2020

APPEARANCES

John D. Corse, Beverly A. Sikora, David E. Ralph, Daniel W. Hurson, Jessica Raba, and Christia H. Ravenell for Baltimore Gas and Electric Company.

Paula M. Carmody, William F. Fields, Joseph G. Cleaver, Gary L. Alexander, and Anna K. Ryon for the Maryland Office of People's Counsel.

Leslie M. Romine, Lloyd J. Spivak, Annette B. Garofalo, and Michael A. Dean for the Maryland Public Service Commission Staff.

Brian R. Greene and Eric J. Wallace for H.A.Wagner, LLC.

Robert A. Weishaar, Jr. for the National Railroad Passenger Corporation (Amtrak).

Don C. A. Parker, Derrick Price Williamson, and Barry A. Naum for Walmart.

John J. McNutt for the United States Department of Defense and Related Federal Agencies.

Margaret M. Witherup and David W. Beugelmans for the Maryland Energy Group.

Lisa Brennan and Jim Ogorzalek for Montgomery County, Maryland.

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INTRODUCTION AND EXECUTIVE SUMMARY

1. On February 4, 2020, the Public Service Commission issued Order No. 89482 ("MRP Pilot Order") in Case No. 9618,[1] establishing a framework for a Multi-year Rate Plan ("MRP") Pilot. On May 15, 2020, Baltimore Gas and Electric ("BGE") filed an Application with the Commission seeking an MRP[2], requesting gas and electric rates to be effective January 1, 2021, January 1, 2022, and January 1, 2023.

2. 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 BGE to increase its electric and gas distribution rates for each of the years of the MRP, with offsets as described in this order, as provided in the chart below.[3]

Electric – Incremental Revenue Requirement	Authorized	BGE Requested	Bill Impact
2021	$59,334,000	$109,958,000	$0.00
2022	$38,696,000	$44,751,000	To Be Determined
2023	$41,879,000	$45,803,000	To Be Determined

[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.

[2] The acronym "MRP" refers to a multi-year rate plan, as discussed and approved for a pilot in Commission Order No. 89482. BGE has referred to its May 15, 2020 multi-year rate plan as an "MYP." For purposes of consistency and to avoid confusion, this Order will use the single term: MRP.

[3] These numbers are incremental increases for each year. The BGE Requested numbers are from the Comparison Charts filed on October 12, 2020.

Gas – Incremental Revenue Requirement	Authorized	BGE Requested	Bill Impact
2021	$53,246,000	$54,189,000	$0.00
2022	$10,769,000	$15,578,000	To Be Determined
2023	$9,872,000	$34,268,000	To Be Determined

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

BACKGROUND

4. The Application was submitted by BGE as the Pilot Utility under the MRP Pilot Order. The Application was supported by the filing requirements[4] approved by the Commission in the MRP Pilot Order and the Direct Testimonies of BGE witnesses Mark D. Case (BGE Ex. 4), David M. Vahos (BGE Exs. 20 and 21), Adrien M. McKenzie (BGE Ex. 17), Ajit Apte (BGE Ex. 8), Robert D. Biagiotti (BGE Ex. 12), A. Christopher Burton (BGE Ex. 6), Tamla A. Olivier (BGE Ex. 10), Mark Warner (BGE Ex. 14), Jason M. B. Manuel (BGE Ex. 26), April M. O'Neill (BGE Ex. 23), and Lynn K. Fiery (BGE Ex. 28) who sponsored BGE's proposed tariffs, Supplement 650 to P.S.C. Md. E-6 (Electric) and Supplement 467 to P.S.C. Md. G-9 (Gas).

5. The Commission docketed BGE's Application as Case No. 9645 and issued Order No. 89556, which suspended the proposed new rates pursuant to Public Utilities Article ("PUA"), *Annotated Code of Maryland*, § 4-204 for 150 days from June 14, 2020. That Order also set a deadline for the filing of petitions for intervention and scheduled a virtual prehearing conference.

6. A prehearing conference was conducted on June 12, 2020, at which the Commission granted the Petitions to Intervene of the following Parties: United States Department of Defense ("DOD"); National Railroad Passenger Corporation ("Amtrak");

[4] The MRP Pilot Order (at 3) required the pilot utility to meet several minimum requirements in its plan, including that it: (i) contain all of the filing requirements found in the PC51 Implementation Report; (ii) allow up to three future rate-effective years with an agreement to "stay out" for that period; (iii) contain specific criteria for any "off-ramp" process (i.e., extraordinary circumstances outside the utility's control that would warrant the Commission's intervention to modify or terminate the MRP); (iv) track the accuracy of the utility's forecast; (v) have an annual informational filing which the Commission may use as the basis for mid-cycle MRP adjustments; and (vi) contain adequate reporting requirements. The Commission finds that BGE's MRP meets the minimum requirements for filing a multi-year rate plan pursuant to the MRP Pilot Order.

Montgomery County, Maryland; Maryland Energy Group ("MEG"); and Walmart, Inc.[5] The Commission also denied the Petitions to Intervene of Delmarva Power & Light Company and Potomac Electric Power Company.[6]

7. Order No 89565, issued June 12, 2020, set a procedural schedule for filing of testimony, hearings for cross-examination of witnesses, filing of briefs and reply briefs. It also set forth procedures for discovery and directed the Parties to arrange hearings for receipt of public comment. Finally, because BGE offered to move the effective dates of its tariffs from June 14 to June 19, 2020, thereby providing an additional five days before a final Order in this matter would be due, the Commission suspended BGE's proposed tariffs for a period of 180 days from June 19, 2020.

8. Hearings for the purpose of soliciting comments from the public were held on July 30, 2020, August 17, 2020, and September 17, 2020 in accordance with Order Nos. 89569 and 89585. BGE filed the Supplemental Direct Testimony of Ran Zhang on July 8, 2020 (BGE Exs. 16a and 16b). On the scheduled filing date of August 14, 2020, the Maryland Office of People's Counsel ("OPC") filed the Direct Testimonies of Cheryl Roberto (OPC Ex. 1), David J. Effron (OPC Ex. 3), Paul Alvarez-Dennis Stephens (OPC Ex. 5, OPC Ex. 5-C, and OPC Ex. 5CEII), Brendan Larkin-Connelly (OPC Ex. 8), Jerome D. Mierzwa (OPC Ex. 10), Dr. J. Randall Woolridge (OPC Ex. 13), and Courtney Lane (OPC Ex. 16). DOD filed the Direct Testimonies of Michael Gorman (DOD Ex. 1) and Christopher Walters (DOD Ex. 2). Walmart, Inc. filed the Direct Testimony of Alex J. Kronauer (Walmart Ex. 1). Amtrak filed the Direct Testimonies of Stan C. Faryniarz

[5] The Commission granted H.A. Wagner's Petition to Intervene Out of Time on August 6, 2020. H.A. Wagner did not file testimony in this case.
[6] Maillog No. 230720.

(Amtrak Exs. 1-5) and Christopher White (Amtrak Ex. 6). MEG filed the Direct Testimony of Daryll Fuentes (MEG Ex. 1). Staff filed the Direct Testimonies of David Hoppock (Staff Ex. 1), Olivia Kuykendall (Staff Ex. 5), Drew M. McAuliffe (Staff Ex. 8), Samrawit Dererie (Staff Exs. 11 and 11-C), John C. Clementson (Staff Exs. 13 and 13-C), Jamie A. Smith (Staff Ex. 15), David L. Valcarenghi (Staff Ex. 17), Anna Joy Thompson (Staff Ex. 19), and Afton Hauer (Staff Ex. 22).

9. On September 11, 2020, BGE filed the Rebuttal Testimonies of Mark D. Case (BGE Ex. 5), David M. Vahos (BGE Exs. 22a and 22b), Adrien M. McKenzie (BGE Ex. 18), Ajit Apte (BGE Exs. 9a and 9b), Robert D. Biagiotti (BGE Ex. 13), A. Christopher Burton BGE (Ex. 7), Tamla A. Olivier (BGE Ex. 11), Mark Warner (BGE Ex. 15), Jason M. B. Manuel (BGE Ex. 27), April M. O'Neill (BGE Ex. 24) and Lynn K. Fiery (BGE Ex. 29). OPC filed the Rebuttal Testimonies of Dennis Stephens (OPC Ex. 5, OPC Ex. 6). Jerome D. Mierzwa (OPC Ex. 11), and Dr. J. Randall Woolridge (OPC Ex. 14). Walmart, Inc. filed the Rebuttal Testimony of Alex J. Kronauer (Walmart Ex. 2). Staff filed the Rebuttal Testimonies of David Hoppock (Staff Ex. 3), Olivia Kuykendall (Staff Ex. 6), Anna Joy Thompson (Staff Ex. 20), and Afton Hauer (Staff Ex. 23).

10. On October 7, 2020, OPC filed the Surrebuttal Testimonies of Cheryl Roberto (OPC Ex. 2), David J. Effron (OPC Ex. 4-revised), Alvarez-Stephens (OPC Ex. 7), Brendan Larkin-Connelly (OPC Exs. 9 and 9-C), Jerome D. Mierzwa (OPC Ex. 12), Dr. J. Randall Woolridge (OPC Ex. 15), and Courtney Lane (OPC Ex. 17). DOD filed the Surrebuttal Testimonies of Michael Gorman (DOD Ex. 4), and Christopher Walters (DOD Ex. 5). Amtrak filed the Surrebuttal Testimony of Stan C. Faryniarz (Amtrak Exs. 8-10). Staff filed the Surrebuttal Testimonies of David Hoppock (Staff Exs. 4 and 4-C),

Olivia Kuykendall (Staff Ex. 7), Drew M. McAuliffe (Staff Ex. 10), Samrawit Dererie (Staff Ex. 12), John C. Clementson (Staff Ex. 14), Jamie A. Smith (Staff Ex. 16), David L. Valcarenghi (Staff Ex. 18), Anna Joy Thompson (Staff Ex. 21), and Afton Hauer (Staff Ex. 24). BGE also filed the Surrebuttal Testimonies of Adrien M. McKenzie (BGE Ex. 19), April O'Neil (BGE Ex. 25), and Lynn K. Fiery (BGE Ex. 30).

11. A trial-type evidentiary hearing was held on October 13, 14, 15, 16, and 19, 2020. At the hearing, all testimonies were admitted into evidence, and BGE was allowed to present live rejoinder testimony to all witnesses as was OPC and Staff regarding the witnesses to which BGE directed surrebuttal testimony.

DISCUSSION AND FINDINGS

I. Revenue Requirement and Adjustments

A. Pace of Rate Increase: Acceleration of Tax Refunds and Extension of Amortizations

12. BGE witness Case stated that in light of the COVID-19 pandemic, the Company is not proposing increases in customer bills for 2021 and 2022, but rather bill increases would begin in 2023.[7] Mr. Case asserted that BGE "has gone to extensive lengths to develop an MRP filing that provides customers greater time before being faced with an increase in electric and gas base distribution bills."[8] Mr. Case stated that BGE can achieve that goal through a series of pro forma revenue requirement adjustments to accelerate the return of certain tax benefits, revise how BGE recovers major outage event restoration expenses, suspend the Smart Grid regulatory asset amortization in 2021, and

[7] Case Direct at 7-8.

[8] *Id*. at 7.

extend the amortization periods of certain existing regulatory assets. Mr. Case also stated that BGE would reduce the magnitude of its return on equity ("ROE") "performance adder"—based on BGE's historic performance and customer satisfaction—that it would have otherwise proposed, absent the pandemic.

13. BGE witness Vahos provided additional detail about BGE's proposal. Mr. Vahos recommended that a performance adder of 35 basis points be added to the 9.9 percent ROE recommended by BGE witness McKenzie. However, to lessen the impact to BGE customers during the COVID-19 pandemic, witness Vahos lowered his recommended performance adder to 20 basis points on top of Mr. McKenzie's proposed ROE, for a final ROE of 10.1 percent.[9]

14. Additionally, Mr. Vahos testified on Operating Income Adjustment 38 and Rate Base Adjustment 14, which provide for the accelerated return of certain tax benefits totaling $287.3 million over the three MRP years.[10] Specifically, Mr. Vahos testified that BGE is proposing to accelerate the reimbursement to customers of tax benefits in the amount of $287.3 million that are primarily attributable to the Tax Cuts and Jobs Act of 2017 ("TCJA") and the Maryland Additional Subtraction Modification ("MASM").[11] This accelerated refund would be effective over the MRP period, starting when the new rates become effective in January 2021 and continuing through calendar year 2023. Mr. Vahos clarified that "BGE proposes to use both outstanding regulatory liabilities [the

[9] Vahos Direct Part 2 at 6.
[10] *Id*. at 7.
[11] *Id*. at 7-8.

TCJA and MASM] as of December 31, 2019 over the three-year [MRP] period, but only to the extent needed to avoid any rate increases in 2021 and 2022."[12]

15. Mr. Vahos stated that Operating Income Adjustment 37 removes $30.6 million of projected incremental major outage event restoration expenses from the electric revenue requirement, and BGE is requesting regulatory asset treatment for major outage event restoration expenses.[13] The budgeted unadjusted operating income for MRP years 2021-2023 includes $10.2 million of incremental major outage event restoration expenses in each MRP year, based on the current five-year average.[14] Mr. Vahos stated that the removal of these costs will help keep base distribution revenues lower than they otherwise would be for customers. To accomplish this, BGE requests authorization to create a regulatory asset for tracking major outage event restoration expenses instead of including the five-year average in the revenue requirement calculation for each year of the MRP period.[15] Mr. Vahos testified that this method would ensure that customers would not pay for actual incremental major outage event restoration expenses until after they are incurred, reviewed in a proceeding, and approved to be included in rates by the Commission.

16. Mr. Vahos stated that Operating Income Adjustment 39 and Rate Base Adjustment 15 reflect the suspension of the amortization of existing base distribution regulatory assets in 2021, resulting in lower expenses being included in the revenue

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[12] *Id*. at 10.
[13] *Id*. at 7.
[14] *Id*. at 11.
[15] *Id*. at 24.

requirement in that year.[16] The adjustments will keep base distribution revenues in the MRP lower than they otherwise would have been for customers.[17]

17. Finally, Operating Income Adjustment 40 and Rate Base Adjustment 16 provide for a five-year extension of the amortization periods of the Smart Grid-related regulatory assets, resulting in lower annual amortization expense.[18] Mr. Vahos testified that previously, the Commission had approved Smart Grid-related regulatory asset lives so that they would be fully amortized as of May 2026. In this proceeding, however, BGE has proposed to extend the lives of Smart Grid-related regulatory assets to December 2031, thereby resulting in a lower annual amortization expense.[19]

18. The parties to this case generally supported BGE's proposal to accelerate tax liabilities and adjust amortizations to prevent an increase in customer bills for the years 2021 and 2022. Given the effects of the COVID-19 pandemic, OPC witness Effron testified that he "consider[s] the mitigation measures being proposed by the Company to be appropriate."[20] Nevertheless, he observed that the adjustments to avoid a rate increase "come with a cost." He calculated that the total value of the special adjustments proposed by BGE in years 2021-2023 comes to $461.7 million, which will have to be recovered in 2023 and the following years, imposing an extra burden on future ratepayers.[21] However, OPC's revenue calculations maintained the proposed zero impact on customer bills for 2021 and 2022.

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[16] Vahos Direct Part 1 at 7.
[17] *Id*. at 50.
[18] *Id*. at 7.
[19] *Id*. at 13.
[20] Effron Direct at 4.
[21] *Id*. at 4-5.

19. Similarly, Staff expressed agreement with BGE's recommendation not to increase base rates for 2021 and 2022,[22] including by extending the amortization period for the Smart Grid regulatory asset from May 2026 to December 2031 and accelerating TCJA tax benefits.[23] Staff witnesses made adjustments to BGE's cost of service, but then adjusted the flowback of tax benefits to arrive at a revenue requirement that preserves the zero impact on customer bills for years 2021 and 2022.[24]

20. Montgomery County stated that gradualism, and the avoidance of rate shock, are fundamental principles of ratemaking. Montgomery County expressed concern that delaying the rate increase through the use of accelerated tax returns and expanded amortizations "may result in rate shock for some customers."[25]

Commission Decision

21. The Commission agrees with the parties that it is appropriate, given the profound impacts of COVID-19 on the State's and the nation's economy and the welfare of Maryland ratepayers, that customers see no net increase in their bills in the year 2021.[26] The Commission therefore accepts BGE's proposal to accelerate tax benefits and to make certain additional adjustments to achieve that result. The Commission will not at this time order the use of accelerated offsets to prevent an increase in customer bills in 2022. Instead, the full revenue requirement necessary to effectuate BGE's rate increase will go into effect beginning in January 2021, offsets will be used to prevent an increase in

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[22] Staff Initial Brief at 9.

[23] Smith Direct at 21, 71.

[24] *See* Valcarenghi Direct at 22.

[25] Montgomery County Initial Brief at 11.

[26] *See*, e.g., OPC Initial Brief at 5 ("Our nation has been in the grip of a global pandemic that has no known end in sight, and is responsible for economic distress for a significant number of households and businesses.")

customer bills for that year, and beginning in the year 2022, customers will see an increase in their bills, subject to potential future adjustment, as discussed below.

22. It is important to observe that blunting the immediate impact of BGE's rate increase comes at a cost. Namely, customers will see a correspondingly higher impact on their bills beginning in 2022 and beyond. The funds being used to offset rate impacts in 2021 will not be available to offset rates in future years. As OPC witness Effron testified at the evidentiary hearings, "there's no free lunch in this regard. It means that customers in the future will be paying higher rates than they would have been in the absence of these special mechanisms."[27] Additionally, the Commission is concerned that offsetting the rate increase for two years undermines principles of transparency by using offsets to make the Company's cost of service look less expensive than it actually is. In other words, as proposed, BGE's significantly higher revenue requirement would begin January 1, 2021, yet customers may not become aware of the fact until two years later when the offsets are largely exhausted.

23. Given the severe health and economic impacts of the COVID-19 pandemic, however, the Commission agrees with BGE and the other Parties that it is prudent to use the tax refunds and certain other adjustments to prevent an immediate rise in customer bills for 2021. But the Commission does not find it appropriate at this time to exhaust the majority of the tax refunds by continuing their accelerated return through the year 2022.

[27] Hr'g Tr. at 634 (Effron).

Doing so would produce an excessively sharp increase in rates in the year 2023 and beyond, raising issues of rate shock and intergenerational equity concerns.[28]

24. Nevertheless, this Order provides flexibility for the Commission to reconsider the use of offsets to reduce the impact of BGE's rate increase in 2022, depending on the state of the economy, the nation's progress in battling COVID-19, and BGE's proposed work plans that will be contained in its 60-day report, as discussed further below. After BGE files that report, stakeholders will have an opportunity to comment on BGE's work plans as well as the use of offsets.

25. The Commission's determination regarding each of the methods of extending the pace of the rate increase is provided below.

26. As more fully described below, the Commission denies BGE's proposal for an ROE performance adder in its entirety. Therefore, BGE's offer to lower the amount of the adder to ostensibly benefit customers is moot.[29]

27. Regarding the TCJA—the legislation was passed on December 22, 2017 and includes a significant reduction of the federal corporate income tax rate, from 35 percent to 21 percent. The legislation took effect on January 1, 2018.[30]

28. In Order No. 88530, the Commission opened a Proceeding in Case No. 9473 to investigate the impacts of the TCJA on the expenses and revenues of Maryland utilities and required such utilities to explain "when and how they expect to pass through those

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[28] Such an outcome would be contrary to the MRP Pilot Order, which found that "One of the key benefits of an MRP is rate stability for both the utility and customers during the rate-effective period." MRP Pilot Order at 26.

[29] As OPC stated: "The proposed performance adder is a benefit to BGE that has not yet been approved by the Commission, therefore BGE has merely offered to forego something to which it is not yet entitled." OPC Initial Brief at 7-8.

[30] *See* Order No. 88530 at 1.

effects to their customers."[31] In its responsive filing,[32] BGE noted that its accumulated deferred income tax ("ADIT") balances, held on behalf of customers, were previously recorded at the higher 35 percent federal income tax rate, but would now be reflected at the lower 21 percent tax rate. The difference between those rates was put into the "excess deferred income tax" regulatory liability for eventual return to customers.

29. In this case, BGE's proposal is to accelerate the return of that customer money. But it is important to note that the money being used to reduce the 2021 and 2022 billing impact of this case comes from customer funds that are being held in the regulatory liability, not from corporate largesse.

30. Given the significant impacts of the COVID-19 pandemic, the Commission accepts BGE's proposal to accelerate the return of this regulatory liability to customers more quickly than the Company had otherwise planned in order to blunt the impact of BGE's MRP rate increase. Indeed, this regulatory liability was originally planned to be returned to customers over a more than 30-year period.[33] The Commission makes the same finding with regard to the MASM. The Commission accepts BGE's proposal to accelerate return of the liability only to the extent necessary to avoid any rate increases in 2021, with the remainder to be returned pursuant to BGE's original timetable. As stated above, however, the Commission retains flexibility to reconsider the acceleration of offsets in the year 2022.

31. The Commission grants BGE's request to create a regulatory asset for tracking major outage event restoration expenses. The creation of the regulatory asset will be

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[31] *Id*. at 2.
[32] Maillog No. 218429, January 5, 2018.
[33] Vahos Direct Part 1 at 10.

helpful for multiple reasons. First, it will help defer costs that would otherwise be imposed on customers during the first two years of the MRP and which would otherwise be especially impactful on customers during the pandemic. Second, as Mr. Vahos testified, major outage event restoration expenses can be "significant and unpredictable in both amount and timing."[34] At this time, ratemaking should prioritize aligning recovery of incremental costs related to major outage events with the actual incremental costs to restore service to customers as a result of those storms, rather than using a five-year average.

32. Finally, the Commission denies BGE's Operating Income Adjustment 39 and Rate Base Adjustment 15, as well as Operating Income Adjustment 40 and Rate Base Adjustment 16. In those adjustments, BGE proposed suspending the Smart Grid Regulatory asset collection for 2021 and a five-year extension of the amortization periods of the Smart Grid-related regulatory assets, resulting in lower annual amortization expense.[35] The adjustment would have extended the amortization schedule so that Smart Grid-related regulatory assets would not be fully amortized until December 2031, instead of May 2026. The Commission finds that this amortization proposal is not in the best interest of ratepayers. First, the extension will impose additional costs on customers in the long run, through additional carrying costs. Second, the extended amortization raises the possibility of requiring payment for smart grid assets beyond their useful lives, which can require customers to simultaneously pay for new assets and unamortized legacy assets.

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[34] *Id*. at 25.
[35] *Id*. at 7.

B. Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC)

Staff

33. Staff witness Smith testified that Construction Work in Progress ("CWIP") should be excluded from BGE's rate base in this MRP, and Allowance for Funds Used During Construction ("AFUDC") should be excluded from operating income.[36] Mr. Smith argued that, by definition, CWIP is plant not used and useful in serving customers during the MRP test period, at least not during the nine months that the associated construction costs are still included in CWIP. Therefore, the costs should not be included in rate base.[37] Mr. Smith testified that customers should only be responsible for plant assets used to provide service.

34. Mr. Smith further testified that in traditional rate cases, the Commission has permitted utilities to include CWIP in the historical test year rate base with the related test year AFUDC income included in operating income.[38] The primary reason for that treatment was to address problems associated with regulatory lag. He stated: "[T]here is regulatory lag associated with the delay from the historic test year until the rate effective year, which is usually over a year and a half later, and a majority of the test year CWIP would likely be in service by that time."[39] However, with the use of an MRP, the regulatory lag no longer exists. "BGE will recover capital project costs timely. BGE will

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[36] Mr. Smith explained that "CWIP is plant that is under construction but has not been completed and thus is not in service and is not used and useful to customers." Additionally, he stated that AFUDC "represents the costs of debt and equity necessary to finance the CWIP…. AFUDC is calculated on capital projects open greater than 30 days using the rate of return authorized in BGE's most recent base rate case." Smith Direct at 14.

[37] Smith Direct at 15.

[38] *Id*. at 14.

[39] *Id*. at 15.

earn a return on plant in service and other components included in rate base, and BGE will recover operating income related costs simultaneously."[40] Mr. Smith additionally stated that CWIP generally accrues AFUDC until the project is moved to plant in service. As a result, Mr. Smith concluded that BGE will recover financing costs and not be harmed.

BGE Rebuttal

35. BGE opposes Staff's recommendation to exclude CWIP from rate base and AFUDC from operating income. BGE witness Vahos observed that there is long-standing Commission precedent for including CWIP in rate base and AFUDC in operating income.[41] Although he acknowledged that having CWIP in rate base and AFUDC in operating income are "largely offset" in the revenue requirement calculation, Mr. Vahos contended that the offset is not complete due to the existence of projects in CWIP that do not accrue AFUDC.[42] Additionally, Mr. Vahos stated that the removal of CWIP from rate base would undermine one of the MRP's benefits of using budgets to set base rates, and would promote regulatory lag, which would be inconsistent with one of the Commission's policy goals in approving a MRP.

Commission Decision

36. The Commission agrees with Staff that CWIP should not be included in rate base and earn a return because it is not used and useful in serving customers. Accordingly, including CWIP in rate base would overstate the plant used to provide service to customers during the rate effective period. Regarding BGE's argument that there is a

[40] *Id*.
[41] Vahos Rebuttal at 39.
[42] Mr. Vahos stated that projects with a construction period of less than 30 days do not accrue AFUDC. *Id*.

long-standing precedent of including CWIP in rate base and AFUDC in operating income, there is of course no precedent relating to Maryland MRPs. This is a pilot case. However, the logic of including CWIP in traditional historic test-year rate cases—that utilities need to be protected from regulatory lag related to expensive projects of long duration—does not apply to an MRP.

37. It is true that in historic test-year rate cases, the Commission has allowed utilities to include CWIP with AFUDC in operating income to mitigate regulatory lag. However, in those cases the Commission was making an exception to the general ratemaking principle that plant must be used and useful to be included in rate base. This exception aided utilities trying to fund large projects who otherwise would have had to wait years to receive any return on their investment. Historically, the Commission has justified the exception because in the traditional rate case, projects started in the test year would typically be completed by the rate effective year, such that a majority of the test year CWIP would be in service by that time.[43] The MRP, however, is an alternative form of ratemaking that substantially reduces the regulatory lag that exceptions like CWIP were meant to ameliorate.

38. Through its MRP, BGE will be able to recover capital project costs in a timely manner, including for projects that are only in the planning stage. As Staff witness Smith testified: "In the past [BGE]set rates based on work that was already done. Now rates are based on the work that's being performed concurrently with the rates being set."[44] The

[43] Smith Direct at 15.

[44] Hr'g Tr. at 1006 (Smith).

prior justification for the CWIP exception is now resolved. Additionally, the burden on BGE of this decision appears to be small.[45]

C. COVID-19 Regulatory Asset

39. BGE has proposed to establish a regulatory asset for the recovery of actual incremental COVID-19 costs, net of savings, over a five-year period beginning in 2023. BGE witness Vahos testified that the incremental costs deferred in the COVID-19 regulatory asset include lost revenues for late payment fees and service application/reconnect fees, certain incremental operating and maintenance costs such as additional personal protection equipment for field employees, cleaning services, sequestration preparation costs, employee benefit-related costs, incremental facilities and vehicle cleaning, incremental security costs, overtime labor costs, public relations and printing of mailers for limited income customers, and other miscellaneous costs.[46] BGE also identified certain savings in the area of travel and entertainment expenses as well as certain utilities expenses.[47]

40. Mr. Vahos stated that BGE is seeking Commission approval of its methodology for calculating incremental write-offs related to the COVID-19 pandemic. Specifically, Mr. Vahos testified: "Once the pandemic-related uncollectible write-offs begin, the Company proposes to calculate the level of incremental pandemic-related write-offs by comparing the level of monthly write-offs at that point in time to the monthly

[45] Mr. Smith testified that disallowing CWIP in rate base only deprives CWIP that is ineligible for accrual of AFUDC from earning a return during the construction period of less than 30 days. Once the plant is moved into plant in service, the plant will be included in rate base and earn a rate of return. Smith Surrebuttal at 5. CWIP balance not accruing AFUDC was estimated to be less than one percent of the average 2019 historical test year total plant balance. Smith Surrebuttal at 5-6.

[46] Vahos Rebuttal at 71.

[47] *Id*. at 74.

uncollectible write-offs included in the historic test year from BGE's last rate case, Case No. 9610."[48] Under normal circumstances, BGE's policy is that customer accounts move to an "uncollectible" status seven months after the account is closed, either through voluntary or involuntary stoppage of distribution service. Given the recent moratorium on disconnections, BGE's COVID-19 regulatory asset currently includes no incremental uncollectible write-offs.

41. Staff witness Smith testified that Staff does not oppose the revenues, costs, or savings included in the COVID-19 regulatory asset.[49] However, Staff has proposed that lost revenues (for late payment charges and service connections) and savings not be included in rate base and therefore not earn a return. Mr. Smith argued that since savings are estimated, the unamortized portion of the savings should not be included in rate base as a reduction in order to be consistent with the treatment of costs.[50] Additionally, because Staff proposed to disallow rate base treatment of the lost revenues, Staff also proposed that the COVID-19 regulatory asset begin amortization in the year 2021 rather than 2023.[51]

42. BGE was agreeable to both of Staff's proposals.[52]

Commission Decision

43. In Order No. 89542, in response to the significant financial implications that utilities could face in complying with emergency orders related to COVID-19, the

[48] Vahos Direct at 15, citing Case No. 9610, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates.*
[49] Smith Surrebuttal at 8.
[50] *Id*. at 9.
[51] *Id*.
[52] BGE Initial Brief at 50.

Commission authorized the utilities to create a regulatory asset to record the incremental costs related to COVID-19 prudently incurred to ensure that Maryland residents have essential utility services.[53] The Commission additionally found that deferral of such costs is appropriate because the current catastrophic health emergency is outside the control of the utilities and is a non-recurring event. In this case, the Commission finds that BGE's methodology for calculating the regulatory asset is reasonable. Accordingly, the Commission grants authority to 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, and that the COVID-19 regulatory asset begin amortization in the year 2021 rather than 2023. Finally, the Commission grants approval of BGE's methodology for calculating incremental write-offs related to the COVID-19 pandemic, by recording the difference between the level of monthly write-offs to the monthly uncollectible write-offs in the historical test year from BGE's last rate case.

D. Gas Cost of Service Issues

1. STRIDE Surcharge and MRP

<u>BGE</u>

44. BGE proposes two alternative methods of treating STRIDE projects. Under the Company's initial proposal, BGE would reset the STRIDE surcharge as of January 1, 2021, at the same time the STRIDE investments through the end of 2020 are moved into rate base. The STRIDE surcharge mechanism would then continue, and certain projects

[53] Case No. 9639, *State of Emergency and Public Health Emergency in the State of Maryland Due to COVID-19*, Order No. 89542 at 2.

would be funded with it subject to its statutory cap. The surcharge would not be reset thereafter until new base rates are made effective in 2024. Any STRIDE revenue requirement amounts above the statutory cap would be recovered through the MRP base rates. STRIDE investments made during the MRP would be treated in the same manner as any other MRP period investment.[54] BGE witness Vahos testified that in the revenue requirement calculation, all STRIDE investments during the MRP would be included in rate base, while all STRIDE surcharge revenues would be included in the operating income calculation, so that customers would be protected against any amounts being recovered in both the STRIDE surcharge and in MRP base rates.[55]

45. In its alternative proposal, BGE would also reset the STRIDE surcharge as of January 1, 2021, as it does in its initial proposal. However, the surcharge would be set to zero at that time and for the *duration* of the MRP period. All STRIDE investments would be included in MRP rate base.[56] Under either proposal, BGE states that it would continue to make all the current periodic reporting, audit requirements, and stakeholder engagements that are associated with its previous STRIDE investments. BGE witness Case testified that the Company was "equally comfortable" with either option.[57]

46. BGE asserts that the Commission has the authority and discretion to adopt either of the Company's proposals. In support of that contention, BGE cites to the Commission's broad, plenary authority to regulate utility base rates under PUA § 2-112 (General Powers), § 2-113 (Supervisory and Regulatory Power), and § 4-102

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[54] Vahos Rebuttal at 28-29.
[55] Vahos Direct Part 2 at 34.
[56] Vahos Rebuttal at 31.
[57] Hr'g Tr. at 23 (Case).

(Commission Power to Regulate Rates). Additionally, BGE references the Commission's authority to implement alternative forms of rate regulation, including surcharges or future test years, contained in the Electric Customer Choice and Competition Act of 1999, including PUA § 7-505(c)(1).[58] BGE argues that by enacting the STRIDE statute 14 years after restructuring, the General Assembly did not intend to limit the Commission's general ratemaking authority or its authority over alternative forms of ratemaking. BGE observes that "the intent of the General Assembly" in passing the STRIDE statute was focused on "accelerat[ing] gas infrastructure improvements in the State," in order to improve public safety and infrastructure reliability. PUA § 4-210(b). The statute was not intended to limit the Commission's broad ratemaking authority. Although BGE recognizes that the STRIDE monthly surcharge is capped at $2 per residential customer, it notes that the General Assembly left intact the Commission's broad authority over base rates, placing no financial limitation on the amount of capital investment that can be recovered therein.[59] BGE concludes, therefore, that applicable law allows for BGE's STRIDE surcharge mechanism to co-exist with the MRP.[60]

OPC

47. OPC witness Larkin-Connolly asserted that BGE's initial proposal to recover revenues above the surcharge cap in base rates would be inconsistent with the STRIDE law insofar as the Maryland legislature determined that $2 per month was the maximum

[58] BGE Initial Brief at 13. BGE argues that the $2 per month per residential customer maximum applies only to the surcharge, not to the overall cost recovery for STRIDE work.

[59] BGE observes that the Commission has repeatedly allowed utilities to roll STRIDE projects out of the surcharge and into base rates during the course of a STRIDE plan, in order to reset the surcharge and begin recovery of additional STRIDE investment. BGE Reply Brief at 36.

[60] BGE Initial Brief at 7.

amount of surcharge it wanted to impose per residential customer.[61] For this reason, he recommended that the Commission require BGE to remove all projected STRIDE plant additions from the MRP, including the plant additions reflected in the Gas Infrastructure Modernization Program ("GIMP") categories for 2020, 2021, 2022, and 2023.[62] Instead of recovering STRIDE costs through the MRP, Mr. Larkin-Connolly argued that BGE should be limited to recovery of STRIDE projects through the STRIDE surcharge up to the surcharge cap.[63] He also recommended that "2020 STRIDE remain in the surcharge until the next base rate proceeding or MRP."[64] In other words, BGE's STRIDE investments for the years 2021 through 2023 would be removed from rate base, placed in STRIDE, and subject to the $2 per customer limit of the STRIDE cap. Any expenditure above that amount—he suggested—would be disallowed.

48. Mr. Larkin-Connolly also opposed BGE's proposal to move all of its projected 2020 STRIDE spend into rate base. He contended that because the proposed STRIDE additions for 2020 are currently "only budgeted amounts" that have not been subject to a prudency review, those 2020 STRIDE amounts should "remain in the surcharge until the next base rate proceeding or MRP."[65]

Staff

49. Staff witness Valcarenghi testified that "Staff is recommending no change to the manner in which [STRIDE] investments are recovered."[66] Additionally, Mr. Valcarenghi

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[61] Larkin-Connolly Direct at 14.
[62] *Id*. at 21.
[63] *Id*.
[64] *Id*. at 22.
[65] *Id*.
[66] Valcarenghi Direct at 14.

did not recommend any disallowance of costs related thereto.[67] He asserted, however, that "surcharge recovery is no longer necessary now that base rates are being developed using projected or forecasted costs just as the STRIDE is developed."[68] He articulated a preference for placing all STRIDE costs in the MRP, stating "BGE's hybrid methodology creates a difficulty of ensuring STRIDE revenues are both adequate and complete. It also has the potential for inaccurate recovery of revenues as STRIDE will be recovered through both base rates and also through the surcharge mechanism."[69] Nevertheless, Mr. Valcarenghi stated that if his proposed adjustment is used, "BGE will recover the same amount whether it recovers STRIDE through a surcharge or through base rates."[70] Mr. Valcarenghi also opined that if STRIDE investments were not included in rate base now, BGE "would be in a worse position than in a traditional case."[71]

50. Staff witness Clementson recommended that all STRIDE projects be accepted by the Commission.[72] He testified that the STRIDE expenditures proposed for the test year, bridge year, and three years of the MRP are in line with the estimated costs for the MRP STRIDE with a difference of $3,910,826, or less than 1 percent.[73]

<u>*BGE Rebuttal*</u>

51. BGE witness Vahos testified that not accounting for STRIDE projects in MRP base rates would relegate STRIDE projects to a worse position than the remainder of

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[67] Valcarenghi Surrebuttal at 7.
[68] Valcarenghi Direct at 14.
[69] Valcarenghi Surrebuttal at 6.
[70] *Id*. at 8.
[71] Hr'g Tr. at 1015, 1017 (Valcarenghi).
[72] Clementson Direct at 2.
[73] *Id*. at 13.

BGE's MRP capital investments, a result that was not contemplated by the legislature.[74] This is because the MRP's stay-out provision precludes BGE from filing another gas base rate case for the three years of the MRP.[75] In a non-MRP environment, BGE would have simply filed a rate case to reset the STRIDE surcharge and place STRIDE projects into rate base sooner.

52. Mr. Vahos further testified that BGE would experience a revenue shortfall of $18 million over the course of the MRP if full recovery of forecasted STRIDE investments is not allowed.[76] Furthermore, if a transfer of the late 2019 and 2020 STRIDE investments is not allowed, as OPC proposed, BGE will hit the cap earlier, which more severely amounts to $50 million in lost revenues over the course of the MRP.[77]

53. Mr. Vahos opposed OPC's recommendation that the 2020 STRIDE costs not be put into MRP base rates because they are "only budgeted amounts." He stated that, to the contrary, a significant portion of the 2020 STRIDE costs sought to be included in the MRP have been validated with actual cost data through the 2020 STRIDE Semi-Annual Report, and "the Company committed to an annual informational filing that would reflect the actual 2020 STRIDE investments."[78] Mr. Vahos further stated that BGE has not proposed a change to the existing STRIDE reporting and filings, "so the Commission and

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[74] Vahos Rebuttal at 29. BGE asserts that OPC's proposal "would effectively subjugate STRIDE investments to a new category below all other distribution [MRP] investments … thereby disincentivizing the replacement of aging gas infrastructure."

[75] Hr'g Tr. at 508-510 (Vahos).

[76] Vahos Rebuttal at 30.

[77] *Id*. at 30.

[78] BGE Initial Br. at 44-45. *See also*, Vahos Rebuttal at 31.

other stakeholders will have a further opportunity to review 2020 actual STRIDE work and the associated costs."[79]

Commission Decision[80]

54. The STRIDE statute was enacted for the purpose of accelerating gas infrastructure improvements in Maryland by establishing a mechanism by which gas companies might promptly recover reasonable and prudent costs of investments in eligible infrastructure replacement projects separate from base rate proceedings.[81] Participation in STRIDE requires a gas company to file a plan for infrastructure replacement that specifies the replacement work to be performed, the cost and timeline for that replacement, and customer benefits under the plan.[82]

55. The process for recovery of project costs is unique under STRIDE (as compared to a traditional rate case) in that estimated project costs are collectible at the same time the eligible infrastructure replacement is made.[83] Upon approval of a plan, the Commission may authorize a surcharge that includes project costs inclusive of retired plant, the company's pretax rate of return, depreciation adjusted to reflect retired plant, and property taxes also adjusted for retired plant.[84]

56. By law, the amount of the surcharge "may not exceed $2 each month on each residential customer account" or a comparable amount for nonresidential customer

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[79] BGE Reply Br. at 38.
[80] Commissioner Richard filed a concurring statement on this issue.
[81] PUA § 4-210(c).
[82] PUA § 4-210(d)(2).
[83] PUA § 4-210(d)(3)(ii). As BGE witness Vahos observed, STRIDE allows the utility to start recovering contemporaneously through the surcharge, before an approved project is used and useful. Hr'g Tr. at 513 (Vahos).
[84] PUA § 4-210(d)(3).

accounts.[85] Completed STRIDE projects must be removed from the surcharge and transferred into rate base at least every five years, but may only be transferred into rate base during a base rate case.[86]

57. In its MRP Pilot Order, the Commission found that the STRIDE surcharge "may play an important role under a Pilot MRP as the combination of STRIDE and an MRP could significantly reduce regulatory lag … ."[87] However, the Commission also observed that "STRIDE investments can only be moved into rate base during a full base rate case (whether traditional or an MRP) in accordance with PUA § 4-210(g)(1)(ii)(2), and not on an annual basis during the course of an MRP rate-effective period."[88] Additionally, the MRP Pilot Order contains a mandatory stay-out provision, which provides that any utility that files an MRP will be prohibited from filing another base rate case for the three-year duration of the plan.[89]

58. BGE makes a compelling argument that the plain language of the STRIDE statute limits the impact to customers only with regard to the surcharge. PUA § 4-210(d)(4) clearly provides that the surcharge "may not exceed $2 each month on each residential customer account." The statute is not worded to limit the financial impact to ratepayers of gas infrastructure replacement generally. The Commission can and has moved STRIDE charges into base rates such that the base rates plus new STRIDE charges

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[85] PUA § 4-210(d)(4). For nonresidential customer classes, the surcharge is capped according to the ratio of non-residential to residential customers in proportion to the total distribution revenues that those classes bear in accordance with the most recent base rate proceedings.
[86] PUA § 4-210(g).
[87] Order No. 89482 at 31.
[88] *Id*.
[89] *Id*. at 3.

impose a burden greater than $2 per month per residential ratepayer.[90] Nevertheless, STRIDE was adopted by the General Assembly at a time when the use of forecasted rates was less common in Maryland, and a surcharge was used as a means to enable utilities to recoup funds used for capital improvements during the building phase of gas infrastructure replacement, rather than completing that replacement and recouping costs through a base rate case. BGE's MRP, in contrast, is another form of alternative ratemaking, which, like STRIDE, is based on forecasting future costs. It is not clear that the General Assembly intended that a utility could put an unlimited amount of gas infrastructure costs on ratepayers through a forecasted, alternative ratemaking mechanism. Ultimately, when the General Assembly crafted such a mechanism—with STRIDE—it imposed a strict surcharge cap.

59. The similarity between STRIDE and BGE's MRP in terms of rate recovery was demonstrated in the colloquy between the Commission and BGE witness Vahos. Mr. Vahos was asked: "[A]re you recovering on STRIDE projects before they become used and useful in any way, shape or form anywhere in the three-year rate-effective period?" He replied "Yes, they're similar to today."[91] And even though one is referred to as a surcharge and the other as an MRP, "the impact on the customer is advanced recovery that the legislature has limited…to $2 and you're getting around that…"[92] Additional

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[90] *See* Hr'g Tr. at 547 (Vahos) (stating that "because of all of the STRIDE investments we've made since the program started," the combined impact of STRIDE investments from the surcharge and base rates is "[d]efinitely north of $2.")

[91] *Id*. at 519 (Vahos – Commissioner O'Donnell).

[92] *Id*. at 519 (Commissioner O'Donnell). The Commission agrees with this statement.

questioning during the evidentiary hearing demonstrated that the combined impact of these two alternative ratemaking proposals would exceed $2 during the MRP.[93]

60. The Commission further finds that BGE's proposal to place some or all of its STRIDE costs in the MRP lacks transparency. The General Assembly required that the surcharge be visible to customers. Placing STRIDE projects directly into the base rates circumvents that transparency by requiring the Commission to approve advanced recovery of STRIDE projects with no visibility to customers, instead mixing STRIDE costs inextricably with all the other elements of BGE's rates.

61. Additionally, the General Assembly put a specific limit on customer bills—choosing $2 per month per residential customer, rather than providing a range or giving discretion to the Commission to consider particular circumstances. For these reasons, although the Commission does not find that the STRIDE statute explicitly forbids an MRP and a surcharge from simultaneously imposing an impact in excess of $2 per month, the Commission finds that doing so would likely be contrary to the intent of the General Assembly.

62. To the extent that Maryland's utilities believe the $2 limit is no longer appropriate, the General Assembly—and not the Commission—is the proper forum in which to make that case. Nevertheless, nothing in this decision should be read to imply that the Commission believes BGE's gas infrastructure replacement projects should be slowed down or are otherwise imprudent. To the contrary, the Commission recognizes

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[93] *See Id*. at 504.

> Commissioner Herman: "But the STRIDE is a statutory program that has a $2 limitation on the residential customer's monthly bill. So it appears to me … that there is at least the potential in 2022 and 2023 for the company to be recovering more than the equivalent of $2 per residential customer."
> Mr. Vahos. "I understand. I don't disagree with that."

that STRIDE projects play a vital role in maintaining a safe and reliable gas distribution system.

63. BGE's arguments that its STRIDE projects will be worse off than other MRP investments unless it is allowed to account for the projects in its MRP base rates are unavailing. BGE chose to file the MRP and, accordingly, it was aware of the three-year stay out requirement contained in the MRP Pilot Order. The utility cannot take advantage of the benefits of the MRP while simultaneously disavowing its disadvantages.

64. The Commission will, however, approve BGE's proposal to place into MRP rates all STRIDE investments through December 31, 2020. This will allow BGE to set the STRIDE surcharge to zero on the first day of its MRP and mitigate the risk that its infrastructure spending will exceed the $2 cap before its next rate case. At a minimum, BGE will have time to make its case to the General Assembly that the cap should be raised before its MRP ends, should it choose to do so.

65. Regarding OPC's concern that not all 2020 STRIDE costs are currently known, the Commission finds that BGE's agreement to present actuals subject to a full stakeholder review will be adequate. The Commission and stakeholders will have the opportunity to review actual cost data, ask BGE questions about any variances, and reconcile actual spend with budgeted figures, just as in any prior STRIDE proceeding. OPC witness Larkin-Connolly conceded during the evidentiary hearing that this process would suffice.[94]

[94] *See Id*. at 785-86 (Larkin-Connolly) "[I]f the process is laid out as I proposed where the company submits a filing, stakeholders are allowed to review it, and then, as Mr. Vahos proposed, an adjustment to the rate base as of January 1, 2021, then I would accept that as being sufficient."

2. Gas Meter Mitigation Relocation and Protection Regulatory Asset

BGE

66. BGE's Gas Meter Relocation and Protection Program is a corrective action plan developed and implemented in response to a residential gas explosion caused by accumulated gas leaks inside a closed, unventilated garage. The Company included $1,118,000 of costs for this program in 2022.[95] BGE witness Olivier testified that BGE's Gas Meter Relocation and Protection Program benefits Maryland ratepayers. She stated that BGE moved customer meters outside of the home, and, in so doing with the installation of bollards, protected them from vehicle strikes and made them accessible to first responders, as well as BGE personnel, in the event of an emergency where gas had to be turned off. She testified that both the public and BGE's customers benefited from this work. Ms. Olivier also stated that BGE completed its gas meter mitigation work in a "cost effective, efficient manner," coming in under budget with the program.[96]

OPC

67. OPC witness Effron asserted that the recovery of the regulatory asset related to BGE's Gas Meter Relocation and Protection Program should be eliminated from the Company's revenue requirement because the program is not complete, which the Commission made a prerequisite for BGE moving the costs into rates.[97] Mr. Effron asserted that BGE has therefore not satisfied the criteria established by the Commission for the recovery of this asset.

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[95] Effron Direct at 22.
[96] Hr'g Tr. at 223 (Olivier).
[97] Effron Direct at 22.

Staff

68. Staff witness Clementson testified that BGE has completed 10,327 bollard installations and 3,003 meter relocations related to this program, and that the remaining jobs include the installation of 1,506 bollards and 77 meter relocations, which BGE indicated would be completed by the end of 2021.[98] In Case No. 9484, Staff recommended that costs related to this program be disallowed. However, Staff testified in this proceeding that it does not oppose recovery of the costs related to BGE's Gas Meter Relocation and Protection Program.

69. Mr. Clementson testified that "Staff does not disagree that BGE executed the BGE's Gas Meter Relocation & Protection Program in a prudent manner and therefore, does not oppose BGE's recovery of these costs…"[99] Staff witness Valcarenghi, however, recommended recovery of the costs over a two-year period in MRP Years 2 and 3 rather than the one-year period proposed by BGE.[100] Staff also observed that program costs were recently incurred as the result of a gas explosion at Stanford Boulevard (in Columbia) in 2019, and more costs may be incurred if the Commission orders a corrective plan in that matter.

BGE Rebuttal

70. BGE witnesses Olivier and Vahos testified that BGE formally completed the Gas Meter Relocation Program by the end of 2019. Ms. Olivier asserted that "the only work remaining involves meters identified prior to the end of 2019 that BGE has, to date, not been able to access for a variety of reasons, as well as any meters needing protection that

[98] Clementson Direct at 10.
[99] *Id*. at 11.
[100] Valcarenghi Direct at 20.

BGE encounters through ongoing gas leak surveys, which the Company expects to be a small quantity."[101] Regarding Staff witness Valcarenghi's recommendation, Mr. Vahos stated that Staff's change to the timing of the recovery is reasonable and BGE is willing to accept Staff's recommendation.[102]

Commission Decision[103]

71. BGE's Gas Meter Relocation and Protection Program has its origins in an explosion that occurred in Columbia, Maryland after a homeowner backed her car out of a townhome garage and struck the inside meter and associated gas piping.[104] In Case No. 9484, the Commission raised the issue of whether BGE incurred these program costs prudently, given the existence of federal pipeline safety regulations and BGE's own Gas Distribution Standards regarding meter location and protection against vehicular and other damages.[105]

72. In Order No. 88975, the Commission granted BGE its Gas Meter Relocation and Protection Program costs incurred up to that date; however, it required that BGE create a regulatory asset for the remaining costs of the Gas Meter Relocation and Protection Program and directed that "when that program is complete and BGE seeks to move those costs into rates, the Company shall demonstrate that such costs were prudently incurred."[106] In particular, the Commission cautioned that BGE "should be prepared to demonstrate that the costs associated with the program are prudent costs that all

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[101] Olivier Rebuttal at 2-3; s*ee also* Vahos Rebuttal at 63.
[102] Vahos Rebuttal at 64.
[103] Commissioner Herman and Commissioner O'Donnell filed a concurring statement on this issue.
[104] Clementson Direct at 9.
[105] Case No. 9484, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to Its Gas Base Rates*, Order No. 88975 at 38.
[106] *Id*. at 45.

customers should bear, and customers should be compelled to participate in the program."[107]

73. In the present case, BGE has provided little evidence that its Gas Meter Relocation and Protection Program is prudent. BGE witness Olivier only briefly addressed the program in her direct and rebuttal testimony.[108] She did, however, discuss the program at the evidentiary hearing, testifying that the program is cost effective and efficient and that it was completed on time and under budget.[109] She also testified that the program provides customer safety benefits, including the relocation of certain meters to the outside of homes, thereby protecting them from vehicular strikes that could cause a gas explosion. The relocation of the meters outside of homes also makes them accessible to BGE personnel and first responders, in the event of an emergency where gas had to be turned off. Finally, the program enabled gas meters to be placed in completely ventilated areas so that "in the event of a gas leak, natural gas will dissipate fully into the atmosphere."[110] Ms. Olivier therefore concluded that the program provides benefits to both BGE customers as well as the public.[111]

74. Additionally, Staff witness Clementson testified during the evidentiary hearing that he saw no evidence of imprudence in the program. "On reviewing the numbers that they had been reporting on a yearly basis, there wasn't a whole lot of fluctuation in the cost, therefore, there wasn't any real appearance of an overspend or a negligent spend."[112]

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[107] *Id*.

[108] *See* colloquy with Commissioner Herman at Hr'g Tr. 222-225 (Olivier).

[109] Hr'g Tr. at 225 (Olivier).

[110] Olivier Rebuttal at 2-3.

[111] Hr'g Tr. at 226 (Olivier).

[112] *Id*. at 990 (Clementson).

For reasons unknown to the Commission, BGE did not present a comprehensive demonstration that the costs associated with its Gas Meter Relocation and Protection Program were prudently incurred. Nevertheless, the Commission finds the testimony given by BGE and Staff at the evidentiary hearing will suffice for prudency purposes.

75. Regarding the completeness of the program, Ms. Olivier and Mr. Vahos also testified that the program was completed by the end of 2019, which was not made known to the Commission proper until the evidentiary hearings in this proceeding. Although BGE concedes that it has not been able to access every meter, the Commission finds that the program is substantially complete.[113] Given this testimony, and in conjunction with Staff's support of the program, the Commission approves the costs included in BGE's Gas Meter Relocation and Protection Program. The Commission accepts Staff's recommendation that BGE recover these costs over a two-year period in MRP Years 2 and 3 rather than the one-year period proposed by BGE. The Commission declines to rule on Staff's recommendation in this case regarding any additional costs related to the Stanford Boulevard explosion insofar as the issue is currently pending before the Commission in Case No. 9653.[114]

[113] The reluctance of a small number of customers to allow access to meters may impede BGE's ability to reach 100 percent completion of this program.

[114] *See* Clementson Direct at 2, stating: "All capital costs and any expenses incurred in BGE's Multi-Year Plan related to the Stanford Blvd. explosion should be placed into a regulatory liability and accrue carrying costs until the Commission acts on the Commission's Engineering Division investigation and the Company completes any associated corrective action plans that may be ordered by the Commission."

E. Electric or Combined Cost of Service Issues

1. Pre-Paid Pension Asset

76. DOD witness Gorman opposed BGE's inclusion of a prepaid pension asset as part of BGE's electric and gas distribution rate base.[115] Mr. Gorman testified that it is only appropriate for a utility to place an asset in rate base and earn a rate of return on the investment where the asset is funded by investor capital and relates to the provision of utility service.[116] However, when an investment is funded by ratepayer dollars, and not investor capital, then it is not appropriate to allow the utility to earn a rate of return on this asset. Mr. Gorman further testified that BGE has not adequately identified how much of its pension expense is actually recovered in rates or met its burden of proof in demonstrating that any portion of the prepaid pension asset was funded by investor capital.[117] Accordingly, Mr. Gorman recommended removing the prepaid pension asset from BGE's cost of service.

77. BGE witness Vahos opposed DOD's recommendation. He testified that the pension asset is very similar to plant investment with respect to inclusion in rate base.[118] Regarding plant investment, investors initially finance the construction, which is placed in rate base and earns a return. The plant is depreciated over the next 40 years, and the annual depreciation expense is included in cost of service and recovered from customers. In this manner, customers gradually "pay back" the investors who financed the plant. The net book value of the plant (original investment less accumulated depreciation) is

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[115] Gorman Direct at 14.
[116] *Id*. at 15.
[117] *Id*. at 19.
[118] Vahos Rebuttal at 58.

properly included in rate base because the net balance financed represents the balance on which the investors are entitled to earn a fair return.[119] Mr. Vahos argued that pension contributions are similar to the investment in plant, in that BGE does not pass pension contributions to customers immediately in cost of service; rather, investors finance those contributions. Pension cost is similar to depreciation expense and is the manner in which the cost of BGE's pension plan is recovered from customers over time. According to Mr. Vahos, at any point in time, investors have financed the plan to the extent to which pension contributions exceed pension cost, and it is appropriate to include that differential in rate base.

78. Mr. Vahos further stated that the existence of a pension asset is a *de facto* indicator of investor funding. If customers funded the pension asset, it would be accounted for as a liability, which would earn a return for customers at BGE's authorized rate of return.[120] However, the prepaid pension has been recorded as an asset, which is confirmed by BGE's audited 2019 balance sheet. Mr. Vahos also cited to past Commission cases, including Case No. 9406, where the Commission recognized the value of the pension as a form of compensation for employees who have provided years of service to BGE.[121] Mr. Vahos further stated that the Commission has a longstanding precedent in BGE rate cases of accepting inclusion of the pension asset in rate base.[122]

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[119] *Id*.

[120] *Id*. at 59.

[121] *Id*. at 59-60 (citing Case No. 9406*, In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*, April 1, 2016 Evidentiary Hearing Hr'g Tr. at 857).

[122] *Id*. at 60 (citing Case Nos. 9610, 9484, 9406, 9355, 9326, 9299, 9230, 9036, and 8829).

79. Mr. Vahos also testified that excluding the prepaid pension asset from rate base would require that the expected return on pension assets also be removed from operating income, which would increase BGE's annual pension expense (to the detriment of ratepayers).[123]

80. In his Surrebuttal Testimony, Mr. Gorman criticized Mr. Vahos' analogy, stating that both plant in-service and a prepaid pension asset should be excluded from rate base if the assets are funded by contributions from customers or sources other than investor funds.[124] He also contested Mr. Vahos' assertion that removing the pension asset from rate base would increase BGE's annual pension expense and costs. Mr. Gorman argued that "customers should get the benefit, *i.e.*, lower pension expense, of the existence of the prepaid pension asset, because they incurred the cost of fully compensating the Company for the existence of this pension asset."[125]

Commission Decision

81. As BGE asserted, the Commission has recognized the value of pensions as a mechanism for attracting and retaining qualified employees, and for that reason, it has a longstanding precedent of accepting the inclusion of prepaid pension assets in rate base.[126] Nevertheless, as BGE witness Vahos concedes, the inclusion of the pension asset

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[123] *Id.* at 61.
[124] Gorman Surrebuttal at 4.
[125] *Id.* at 6.
[126] Nevertheless, the Commission recently determined that ratepayers should not pay for certain Supplemental Executive Retirement Plans to company executives outside of Internal Revenue Service limits. Case No. 9481, *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and to Revise Its Terms and Conditions for Gas Service*, Order No. 88944 (Dec. 11, 2018) at 65-66.

was not a contested issue in most of the cases cited by the Company, so the Commission's orders on those rate cases did not squarely address the present issue.[127]

82. However, in Case No. 9092 (also cited by BGE), the Commission considered the assertion by the University of Maryland College Park that the pension asset contained in Potomac Electric Power Company's ("Pepco") rate base was actually financed through customer funds and therefore should not be included in rates.[128] In that case, the Commission found that "no exclusion is warranted for the pre-paid pension balances," and that investor funds, rather than customer funds, were used to finance the pension.[129]

83. Likewise, in the present case, the Commission finds that prepaid pension assets, like plant investment, should be included in rate base. BGE investors finance pension contributions in the first place, and they are gradually recovered from customers over time through pension costs. Therefore, the investors should be compensated for the value of their investment and the prepaid pension asset properly belongs in rate base until such time as pension costs fully repay the investment. In that regard, it is informative that the prepaid pensions were recorded as a pension asset, rather than a liability, as confirmed by BGE's audited 2019 balance sheet. BGE has presented sufficient evidence that investor funds were used to finance the prepaid pension asset, and it is properly placed in rate base.[130]

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[127] Vahos Rebuttal at 60, n. 68.

[128] Case No. 9092, *In the Matter of the Application of Potomac Electric Power Company for Authority to Revise Its Rates and Charges for Electric Service and For Certain Rate Design Changes*, Order No. 81517 (July 19, 2007).

[129] *Id*. at 38-39.

[130] Nevertheless, DOD has raised an important issue and BGE could improve its documentation to demonstrate that shareholders rather than ratepayers financed the pre-paid pension assets. In future MRPs, the Commission will look to the utility for enhanced documentation.

2. Contingencies (Capital Spending)

84. In its MRP, BGE included contingency amounts in its capital budgets for certain large gas capital and IT projects. BGE stated that it determines the contingency amounts needed on a project-by-project basis at the discretion of its project managers.

85. OPC witness Larkin-Connolly opposed BGE's proposal to include contingency amounts in the MRP capital budgets. Mr. Larkin-Connolly noted that in Case No. 9486, the Commission ordered WGL to remove proposed contingency amounts from the STRIDE project costs that would be used to set its annual STRIDE surcharge.[131] Mr. Larkin-Connolly participated as a witness in that case, testifying that if a project incurs unforeseen costs that result in overruns, "[r]ather than build some contingency into the estimate to account for these costs upfront … it is more appropriate to wait until the reconciliation stage of STRIDE so that the Commission can evaluate the cost driving the variance and determine if it is a prudent expense."[132] In the present case, Mr. Larkin-Connolly recommended that the Commission require BGE to remove contingencies from its MRP plan, arguing customers should not be required to pay for overrun costs upfront prior to a prudency review. Accordingly, Mr. Larkin-Connolly recommended that all gas capital contingencies identified by BGE be removed from the MRP, resulting in a

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[131] Larkin-Connolly Direct at 73 (citing Case No. 9486, *In the Matter of the Application of Washington Gas Light Company for Approval of a New Gas System Strategic Infrastructure Development and Enhancement Plan and Accompanying Cost Recovery Mechanism).* Although Mr. Larkin-Connolly argued in his pre-filed testimony that the Commission found in Case No. 9486 that it would be "inappropriate" for utilities to include contingency amounts in the budgets for project costs used to set rates, he acknowledged during the evidentiary hearing that the Commission's finding was not so sweeping. *See* Hr'g Tr. at 834-37 (Larkin-Connolly).

[132] Larkin-Connolly Direct at 74.

reduction of $7.4 million in the 2020 budget, $1.1 million in the 2021 budget, $4.1 million in the 2022 budget, and $0.01 million in the 2023 budget.[133]

86. OPC witnesses Alvarez and Stephens also testified that contingency budgets are inappropriate for forward test year ratemaking such as the present MRP.[134] They stated that contingency budgets "are not a projection of costs the project manager expects; rather, they are projections of costs the project manager warns might be required over and above the project manager's best estimates at the time they are made."[135] Nevertheless, contingency budgets that are not spent effectively increase the authorized rate of return to the utility, and compensate the utility for capital which was not spent. Accordingly, witnesses Alvarez and Stephens testified that there are three important rationales for excluding contingencies, which are: (i) in a forward test year environment, capital bias encourages a utility to make contingency budgets as large as the utility can justify; (ii) unspent contingency budgets represent an unauthorized increase in the rate of return for the utility; and (iii) including contingency budgets in an MRP does not encourage project spending control.[136] Messrs. Alvarez and Stephens clarified that they were not recommending that cost overruns be disallowed categorically; rather, they were recommending that accelerated cost recovery should not be available on project contingency budgets. Their recommendation was to reduce Electric Distribution and Electric IT amounts by $13.4 million, $3.2 million, $2.5 million, and $1.0 million in 2020, 2021, 2022, and 2023 respectively.

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133 Larkin-Connolly Direct at 75.
134 Alvarez / Stephens Direct at 50.
135 *Id*. at 51.
136 Alvarez / Stephens Surrebuttal at 42.

87. BGE witness Apte testified that the Company takes a conservative and measured approach to developing contingency budgets to ensure that the amounts included are reasonable and needed to support the project.[137] He stated that BGE does not include contingencies for every project, but rather reflects them on a limited basis, and generally reserves them for "highly complex, and therefore riskier, projects."[138] Mr. Apte further stated that BGE was not attempting to inflate its budgets—arguing that some projects will need more contingency funds than they have available, while others will need less, such that in the aggregate, the contingency dollars "represent an amount of money that we anticipate to fully utilize to support the projects being executed."[139]

88. BGE witness Vahos also argued that because forecasting is an integral part of an MRP, and because contingencies are an inherent part of the forecasting and budgeting process, the Commission should accept a level of contingencies in BGE's MRP for both O&M and capital costs. Finally, Mr. Vahos stated that if the budgeted costs included in MRP rates do not include contingencies, BGE would be harmed by the asymmetrical nature of the annual informational filing and reconciliation process.[140] He argued that waiting until the reconciliation, without the benefit of carrying costs, would lead to regulatory lag.

89. In his Surrebuttal Testimony, OPC witness Larkin-Connolly stated that in this rate case, he attempted to limit the capital budgets used to set base rates to amounts BGE has shown "are based on tangible, specified work plans," further asserting: "Contingency

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[137] Apte Rebuttal at 39-40.
[138] *Id*. at 40.
[139] *Id*.
[140] Vahos Rebuttal at 52.

budgets, by their very nature, do not represent known activities because they are funds set aside for unknown events."[141]

Commission Decision

90. The Commission finds that BGE should remove contingency amounts in its capital budgets. The MRP process requires the utility to use its best judgment to accurately forecast the budget that it will need to safely and adequately operate its distribution system on behalf of its customers, including the costs for large capital and IT projects. There are financial implications to customers and the utility for overestimating (or underestimating) that budget. However, given the information, resource, and expertise asymmetries[142] inherent in MRPs, BGE is in the best position among the Parties to forecast accurately. Additionally, it would be inappropriate to impose on ratepayers the additional costs of funding a cushion above BGE's best estimate. As in Case No. 9486, the Commission finds it is more prudent to wait until the reconciliation stage to address potential cost overruns.[143] The Commission is also concerned that including contingencies in BGE's budgets could undermine the utility's incentive to control project costs, and improperly shift the risk of cost overruns to ratepayers.[144] The Commission

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[141] Larkin-Connolly Surrebuttal at 48.

[142] *See* OPC Initial Brief at 27.

[143] During the evidentiary hearing, there appeared to be confusion regarding the timing of the reconciliation. For purposes of clarification, the MRP Pilot Order did not approve an annual reconciliation process. To the contrary, the Order provided: "[I]n lieu of an annual reconciliation, the Pilot Utility must file an annual informational filing within 90 days of the end of the first and second annual periods during the Pilot MRP. The annual informational filing shall contain worksheets and a detailed explanation showing the differences between a utility's MRP forecasted projections for the annual period and what the utility actually collected and spent in that year." MRP Pilot Order at 3-4. As applied to the instant case, the reconciliation process will occur at the end of BGE's MRP.

[144] *See* MRP Pilot Order at 21 (finding: "the Pilot Utility should bear the risk of forecasting errors.").

agrees with OPC that it would be inappropriate to require customers to pay for overrun costs upfront prior to a prudency review.

3. Contingencies (O&M)

91. OPC witness Effron testified against BGE's inclusion of allowances for contingencies in its forecasts of O&M expenses in the MRP. He testified that the contingencies "are not actual expenses, but rather potential expenses that might, or might not, be incurred,"[145] and would not be recoverable in a traditional rate case. He opined that they should not be included in the MRP either. Accordingly, Mr. Effron recommended that BGE's IT Project contingencies be eliminated from O&M expenses in years 2021, 2022, and 2023, which would reduce electric O&M expenses by $1,062,000, $812,000, and $187,000 and gas O&M expenses by $536,000, $410,000, and $95,000 in MRP years 2021, 2022, and 2023, respectively.[146] Mr. Effron further testified that it would be inappropriate to include an asymmetric contingency adjustment that provides additional revenue for the utility due to the possibility of overspending, while failing to credit customers for the potential of underspending.[147]

92. BGE witness Vahos testified that "contingencies for additional hardware, software, consulting fees and labor costs are generally built into the budget to cover risks associated with project scope, resource availability, and other potential system issues identified in testing."[148] He also contended that forecasting is an essential element of an MRP and that it appropriately includes contingencies. Mr. Vahos further asserted that

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[145] Effron Direct at 20.
[146] *Id*. at 21.
[147] Effron Surrebuttal at 11.
[148] Vahos Rebuttal at 51.

disallowing contingencies would harm BGE by imposing on it the risk that it would have to wait until reconciliation to recoup cost overruns, thereby exacerbating regulatory lag.[149]

Commission Decision

93. The Commission directs BGE to remove contingencies in the Company's forecasts of O&M expenses in the MRP. As discussed above regarding capital spending contingencies, the utility is in the best position to forecast costs accurately. Given the many benefits the MRP affords BGE, including significantly reduced regulatory lag, the Commission finds it would be inappropriate to shift the risk of cost overruns onto ratepayers by including contingencies in O&M expenses. BGE should not be in the position of collecting additional revenue from customers to pay for the possibility of a cost overrun prior to the prudency review. Project cost overruns will be subject to the prudency review/rate base reconciliation process anticipated in the follow-on rate case at the end of the MRP period.

4. Depreciation

94. OPC witness Effron disputed the plant depreciation and amortization expense included in BGE's revenue requirements over the course of the MRP. He observed that BGE used different composite depreciation rates for each year of the MRP.[150] Specifically, Mr. Effron noted that in the 2019 historic test year, the ratio of electric depreciation expense to the average balance of electric plant in service (the "composite depreciation rate"), was 3.04 percent. However, in the 2020 bridge year, the composite

[149] *Id*. at 52.
[150] Effron Direct at 24.

depreciation rate increases to 3.12 percent. The composite depreciation rate then increases in each year of the MRP until reaching 3.24 percent in 2023. For gas plant in service, the composite depreciation rate was 2.98 percent in the historic test year.[151] It increases to 3.10 percent in the bridge year and remains relatively steady over the course of the MRP.

95. Mr. Effron stated that the composite depreciation rate should not vary materially from year to year unless there are specific reasons justifying that change.[152] Regarding BGE's composite gas depreciation rate, for example, he noted that the gas depreciation accrual rates were revised in Case No. 9610, and the composite gas depreciation rate increased. He found this "provides a valid explanation of the increase in the composite gas depreciation rate from 2.98% in 2019 to 3.10% in 2020."[153] However, Mr. Effron found no corresponding justification for the increase in the composite electric depreciation rate that BGE is projecting for the 2020 bridge year and the years of the MRP. Mr. Effron explained that although depreciation expense will increase as plant in service increases, there is no evidence that plant additions in 2020-2024 will have higher depreciation or amortization rates than plant in service during the historic test year.

96. Mr. Effron stated that there have been no further changes in the electric depreciation accrual rates since Case No. 9610, and there is no indication of disproportionate plant additions with higher depreciation or amortization rates in the years 2020 through 2024. Therefore, he used a composite rate of 3.04 percent to

[151] *Id.*
[152] *Id.*
[153] *Id.* at 25.

calculate the electric depreciation expense to be included in BGE's electric revenue requirement in MRP years 2021, 2022, and 2023.[154]

97. BGE witness Vahos testified against Mr. Effron's proposal, stating that it is "entirely based on a hypothetical mathematical exercise" that produces a composite rate "significantly less than the rate in the Company's MRP."[155] Mr. Vahos asserted that the calculated depreciation rate will fluctuate depending on the lives of the assets being placed in service, and that an influx of assets included in depreciation expense with shorter than average depreciation lives will result in an increase in the composite rate.[156] He further stated that in the years 2021-2023, "the Company is implementing a variety of IT investments which do generally have shorter than average lives."[157] He concluded that "the impact of these initiatives, with their shorter amortization lives, is a legitimate cause for the increasing composite rate Witness Effron notes in his [depreciation] calculations."[158]

98. In his Surrebuttal testimony, Mr. Effron asserted that BGE's additional information does not explain or address its projected increase in the composite depreciation rate from 2019 to 2020.[159] However, for the year 2023, Mr. Effron modified his recommendation based on the additional information provided from BGE regarding the inclusion in 2023 of IT investments with shorter than average lives that would impact

[154] *Id*. at 26.
[155] Vahos Rebuttal at 53.
[156] *Id*. at 54.
[157] *Id*.
[158] *Id*. at 55.
[159] Mr. Effron noted that BGE provided documentation supporting IT investments with shorter than average lives for 2021 and 2022. However, given the small amount of IT investment in those years relative to BGE's total plant additions, Mr. Effron argued that those IT investments would not noticeably affect the composite depreciation rate. Effron Surrebuttal at 13.

the composite depreciation rate. As a result of that information, Mr. Effron recommended a composite depreciation rate of 3.08 percent for the year 2023.[160]

Commission Decision

99. The Commission directs BGE to make the depreciation adjustments recommended by OPC witness Effron.[161] The Commission's policy is to require a depreciation study in order to change depreciation rates.' [162] Where a utility presents a rate case without a depreciation study, as BGE has done here, the Commission's policy is to use the depreciation rate last accepted by the Commission that resulted from the utility's last depreciation study.

100. The Commission agrees with Mr. Effron that the composite depreciation rate should not vary materially from year to year unless there are specific reasons justifying that change. In this case, BGE has not presented a depreciation study or a sufficient record to justify the change in composite depreciation rates it has proposed. The Commission therefore accepts the depreciation adjustment calculated by OPC witness Effron. Included in that calculation is Mr. Effron's composite depreciation rate of 3.08 percent for the year 2023. Given that this case is a pilot, that BGE provided evidence of

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[160] *Id*. at 14.

[161] Depreciation is commonly understood to be "the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of property. These factors embrace wear and tear, decay, inadequacy and obsolescence." Public Service Com. v. Balt. Gas & Elec. Co., 273 Md. 357, 371 n. 4 (1974). The Commission has also stated that "the purpose of depreciation is to recover the original cost of investments spread over the service life of the purchased assets." Re Potomac Electric Power Co., 74 Md. PSC 113, 117 (1983).

[162] Order No. 85724, *In the Matter of the Application of Potomac Electric Power Company for an Increase in Its Retail Rates for the Distribution of Electric Energy*, Case No. 9311, at 3 (July 12, 2013) ("As we have noted in the past, depreciation rates should be adjusted pursuant to a depreciation study, where all aspects of depreciation can be examined together and piecemeal changes are avoided[.]"); Order No. 85374, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in Its Electric and Gas Base Rates*, Case No. 9299, at 41 (Feb 22, 2013) ("OPC's proposed depreciation expense adjustments were not proposed in the context of a full depreciation study, and for that reason we reject its proposal on its face.").

IT investments with shorter than average lives that could impact the composite depreciation rate, and that the evidence was accepted by OPC in its calculation, the Commission will make an exception—in this case—from its general policy not to change a depreciation rate without a depreciation study for that one year.

5. Minor Storm Damage Expense

101. BGE witness Biagiotti testified that BGE's Storm O&M budget is based on a five-year average of minor storms plus $10 million annually for major storms, with the $10 million major storm figure determined through a five-year average.[163] BGE included minor storm damage of $27,210,000 in 2021, $28,312,000 in 2022, and $29,199,000 in 2023.[164] Mr. Biagiotti stated that the trend for this category is flat, with the exception of inflation in labor and material costs.

102. OPC witness Effron opposed the amount of BGE's Minor Storm Damage expense, observing that the actual average minor storm damage expense for the years 2015 through 2019 was only $19,855,000. Mr. Effron asserted that the minor storm damage expense forecasted by BGE for the years 2021 through 2023 "bears no discernible resemblance to this level of expense."[165] Mr. Effron stated that the disparity stems from BGE's calculation of *indirect* minor storm damage expense, which for the years 2015 through 2019 averaged $6.2 million, but which BGE's forecast for the years 2021 through 2023 ranges from $13.9 million to $15.3 million.[166] Because he found BGE's forecast of indirect minor storm damage to be inflated, Mr. Effron calculated the

163 Biagiotti Direct at 26.
164 *Id*. at Exhibit RDB-1, page 34.
165 Effron Direct at 13.
166 *Id*. at 14.

actual indirect minor storm damage expense for the years 2015 through 2019 as a percentage of direct minor storm damage expenses for those years, and determined the average was 45.7 percent.[167] Mr. Effron then applied the 45.7 percent ratio of indirect costs to direct costs to BGE's forecasted direct minor storm damage costs for the years 2021 – 2023, to calculate the year-by-year indirect minor storm damage costs.

103. BGE witness Vahos opposed OPC's recommendations for several reasons. First, Mr. Vahos stated that reducing overhead costs allocated to minor storm expenses would only result in the increase of overhead costs charged to other field projects, with no net change in the budget or cost of service.[168] Second, he asserted that Mr. Effron's approach does not take into consideration certain system changes[169] made by BGE in 2017, which made the indirect costs of 2015 and 2016 not comparable to the indirect costs starting in 2017. Third, Mr. Vahos argued that indirect minor storm O&M expense is primarily driven by the allocation of overhead costs and fleet costs across the entire portfolio in every year of the budget—not historical indirect minor storm spending.

104. In his Surrebuttal testimony, Mr. Effron agreed that the forecast of indirect minor storm damage costs in the MRP should reflect the current method of allocating indirect costs. Therefore, he eliminated the years 2015 and 2016 from his calculation of the ratio of indirect costs to direct costs and determined a new ratio of 57 percent. Applying that

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[167] *Id*. at 15.

[168] Vahos Rebuttal at 46.

[169] Mr. Vahos stated that BGE implemented a new budgeting tool named the Work Planning and Tracking system, which has system architecture differences from the budgeting tool used prior to 2017.

figure, he totaled minor storm damage expenses of $20,928,000, $21,453,000 and $21,989,000 for the years 2021, 2022, and 2023, respectively.[170]

Commission Decision

105. The Commission finds that BGE's method of calculating minor storm damage expense is reasonable. Part of the reason for this expense increase over the three years of the MRP compared to historical levels, which in turn caused OPC to scrutinize the expense, is because BGE unveiled its new Work Planning and Tracking system in 2017. That system allocated indirect storm costs differently than in previous years. However, reducing the overhead costs allocated to the minor storm damage expense would likely result only in the increase of overhead costs that will be charged to other field projects, with no net benefit to customers. Additionally, as Mr. Vahos explained, the indirect minor storm O&M expense is primarily driven by the allocation of overhead costs and fleet costs, not historical indirect minor storm spending. Therefore, OPC witness Effron's proposed alternative methodology for calculating this expense, which relies on a historical ratio of indirect costs to direct costs, is not likely to produce a more accurate forecast than BGE's methodology.

6. Forecasted Customer Additions

106. BGE's forecasts for the 2020 bridge year and years 2021, 2022, and 2023 of the MRP indicate that the Company will add new electric customers from a low of 3,743 in 2021 to a high of 10,232 in 2023. BGE has also forecasted 4,672 new gas customers in 2020 and 5,411 new gas customers in each year of the MRP.[171]

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[170] Effron Surrebuttal at 8.

[171] Effron Direct at 10 (citing BGE Response to Staff Data Request 19-38).

107. OPC witness Effron questioned the accuracy of BGE's customer forecasts. He examined the actual number of customer additions in the years 2015 through 2018 and found that number to be larger than the forecasted number of customers for 2020 through 2023.[172] He concluded that BGE's forecasts are "out of line with the actual experience in recent years" and that the Company has underestimated the number of customer additions in its forecasts.[173] Accordingly, he proposed to use the average actual customer additions in the years 2015 through 2019 to quantify an adjustment to the Company's forecasts of new customers in the years 2020 through 2023. Because higher forecasted customers lead to higher forecasted customer revenue growth, Mr. Effron attributed higher base electric and gas distribution revenue to BGE.[174]

108. BGE witness Vahos responded that OPC's position is based on a simplistic assessment of historical activity and is not as accurate as BGE's customer growth forecast, which is supported by sophisticated econometric models.[175] Mr. Vahos also stated that BGE's lower forecasted growth for residential customers in 2020 and 2021 (compared to the time period 2015-2019) reflects the projection of a mild recession from the fourth quarter of 2020 through the second quarter of 2021, resulting from COVID-19.[176] Mr. Vahos further stated that the relatively high number of customers in 2020 is somewhat misleading because BGE responded to the COVID-19 pandemic by ceasing customer terminations starting in mid-March 2020, resulting in a higher number of

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[172] *Id*.
[173] *Id*. at 10-11.
[174] Mr. Effron calculated increases in base electric distribution revenues of $5,618,000, $6,554,000 and $6,822,000 for years 2021, 2022, and 2023, respectively. He calculated increases in base gas distribution revenues of $1,089,000, $1,423,000 and $1,757,000 for 2021, 2022, and 2023, respectively. *Id*. at 12.
[175] Vahos Rebuttal at 48.
[176] *Id*. at 48.

customers than initially budgeted in 2020. Mr. Vahos contended that this temporary absence of service disconnections almost entirely makes up the customer differential that Mr. Effron cited in his Direct Testimony.

109. BGE witness Fiery testified that if Mr. Effron's proposal is accepted, "it would create a disconnect between the revenue requirement and rate design assumptions" that would require an updated compliance filing.[177]

110. Staff did not support or oppose OPC's position regarding customer additions.[178] However, Staff witness Hoppock noted that if the Commission adopts Mr. Effron's adjustment to BGE's residential electric and gas customer count forecasts, it will also need to make an adjustment to residential electric and gas sales. Mr. Hoppock further stated that OPC did not present revised Schedule R or Schedule D forecast volumetric sales in its testimony—or in response to Staff's data request—in order to make the required adjustments to residential electric and gas sales.

Commission Decision

111. The Commission finds that BGE's econometric model will provide a more accurate predictive tool than OPC's approach regarding customer additions. Although Mr. Effron demonstrated that BGE's projected customer additions for 2020 through 2023 are lower than the number of new customers from 2015 to 2019, BGE has provided satisfactory explanations, including the effects of the COVID-19 pandemic. Additionally, the Commission observes that the review and reconciliation process of this MRP will protect ratepayers from over-collection. If BGE's projected customer additions

[177] Fiery Rebuttal at 31.

[178] Hr'g Tr. at 924-25 (Hoppock); Hoppock Rebuttal at 7-8.

prove to be understated, its revenues will be higher, which will be reported in BGE's Annual Informational Filing. As Mr. Vahos stated, "to the extent there is a significant disparity between revenues and expenses to the detriment of customers, rates can be adjusted to reflect those changes."[179] Moreover, the Commission will hold a reconciliation process at the conclusion of the MRP, where the difference between forecasted and actual amounts will be evaluated, and any amounts owed to customers will be refunded with carrying charges.

7. Property Tax Expense

112. BGE determined its year-by-year property tax expense over the term of the MRP by applying an 8 percent growth rate based on average historical growth and management judgment to property tax assessment amounts.[180] The 8 percent growth rate was calculated from the compound annual growth rate in property tax assessments for the tax assessment years 2016/2017 through 2019/2020. The 8 percent annual growth rate was then applied to the 2020 property tax expenses to project the electric and gas property tax expenses for 2021, 2022, and 2023.

113. OPC witness Effron testified that BGE's method of determining the property tax expenses to be included in the calculation of the Company's revenue requirements for the years 2021 through 2023 was not appropriate.[181] First, as a matter of math, Mr. Effron stated that the compound annual growth rate in property tax assessments for the tax assessment years 2016/2017 through 2019/2020 is 7.1 percent, not 8 percent. Second, Mr. Effron argued that the changes in property taxes over three years do not establish a

[179] Vahos Rebuttal at 49-50.
[180] Vahos Direct at 37.
[181] Effron Direct at 28.

reliable and consistent trend that can be used to project the property tax expenses to be included in the Company's revenue requirements for the years 2021, 2022, and 2023.[182]

114. To demonstrate this principle, Mr. Effron used property tax information beginning in 2013/2014 to determine the compound annual growth rate in property taxes over a six-year period, which he calculated to be 5.7 percent.[183] Nevertheless, Mr. Effron argued that it would be "more reasonable to project property taxes based on the latest known assessments and tax rates than it is to project those property taxes based on the historic compound growth rate over some arbitrary number of years," whether that number is three or six.[184] Instead of relying on historic averages that can vary depending on which years are included, Mr. Effron recommended projecting property taxes by determining the current ratio of property tax expense to plant in service, and applying that ratio to projected plant balances.[185] Mr. Effron calculated those ratios at 1.23 percent for electric plant in service and 1.21 percent for gas plant in service.[186]

115. BGE witness Vahos opposed OPC's recommendation, stating that the determination of assessed value is not solely a function of the plant balance, but rather is based on multiple factors including net plant in service, net operating income, and the judgment of the Maryland State Department of Assessments and Taxation ("SDAT"),

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[182] *Id*.

[183] *Id*. at 28-29.

[184] *Id*. at 29.

[185] *Id*.

[186] In determining plant balances to which these ratios should be applied, Mr. Effron reflected the plant adjustments being proposed by OPC witnesses Larkin-Connolly, Alvarez, and Stephens, and calculated reductions in electric property tax expense of $4,511,000, $8,586,000, and $13,063,000 and to gas property tax expense of $1,962,000, $3,862,000, and $5,797,000 for the years 2021, 2022, and 2023, respectively.

among other factors.[187] Mr. Vahos asserted that it is more appropriate to base the budgeted property taxes on historical trends and management's judgment, rather than the methodology proposed by Mr. Effron. Regarding the derivation of the 8 percent growth rate, Mr. Vahos acknowledged that the compound annual growth rate is 7.1 percent for the last three years, but he stated that there were two years in that period (2017/2018 and 2018/2019) where the annual growth rate was 8 percent or higher, that it is expected that the 2020/2021 property tax level will approximate the projected 8 percent increase, and that therefore, the 8 percent annual increase reflected in BGE's budgeted property taxes is appropriate.[188]

116. In his Surrebuttal Testimony, Mr. Effron remarked that BGE's "judgment" in determining forecasted property taxes merely "consists of taking the 'historical trend' in property taxes for the three assessment years ended 2019/2020 and then rounding that trend up from 7.1% to 8%."[189]

Commission Decision

117. The Commission finds generally reasonable BGE's method of determining its year-by-year property tax expense over the term of the MRP. The Company derived an 8 percent annual growth rate from the compound annual growth rate in property tax assessments for the tax assessment years 2016/2017 through 2019/2020. The Company then applied that rate to the 2020 property tax expenses to project the electric and gas property tax expenses for 2021, 2022, and 2023. The Commission does not find OPC's approach of projecting property taxes by determining the current ratio of property tax

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[187] Vahos Rebuttal at 56.
[188] *Id.*
[189] Effron Surrebuttal at 14.

expense to plant in service and then applying that ratio to projected plant balances to be a superior approach. Nevertheless, OPC witness Effron demonstrated that the compound annual growth rate in property tax assessments for the tax assessment years 2016/2017 through 2019/2020 is 7.1 percent, not 8 percent. BGE witness Vahos conceded that point.[190]

118. Although BGE witness Vahos argued that management's judgment should be used to effectively round up the compound annual growth rate in property tax assessment to 8 percent, the Commission finds that BGE has not substantiated that rounding on this record. Accordingly, BGE's methodology for determining year-by-year property tax expense over the term of the MRP will be used, but with a 7.1 percent rather than an 8 percent growth rate.

8. Non-Labor O&M Inflation

119. In order to estimate non-labor O&M inflation, BGE used a 2.5 percent per year inflation forecast derived from the IHS Consumer Price Index, All Urban data, as of April 26, 2019.[191] BGE stated that it used a single escalation factor of 2.5 percent throughout the MRP period for both labor and non-labor to simplify assumptions and create efficiencies in the budgeting process.[192] Using that factor, the Company estimated that the amount of non-labor O&M due to inflation is approximately $9 million per year in each of the MRP years 2021, 2022, and 2023.

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[190] Vahos Rebuttal Testimony at 56 (noting that "the [compound annual growth rate] for property taxes for the last three years is 7.1%").

[191] *Id*. at 40.

[192] Gorman Direct at 21, citing BGE response to Data Request DOD-FEADR 02-07. BGE stated that an exception exists in the case of negotiated contracts.

120. DOD witness Gorman testified that BGE's 2.5 percent escalator factor was not an appropriate measure of general inflation during the MRP.[193] He argued that this inflation rate does not reflect the consensus of independent economists regarding projections of inflation over the forecast period. Mr. Gorman articulated three specific concerns regarding BGE's escalation factor, which are: (i) the data BGE relied upon is over a year old and does not reflect independent economists' current estimates; (ii) BGE did not sufficiently support its proposed 2.5 percent escalator; and (iii) BGE's proposed escalator does not appear to consider any productivity gains, or other factors, that would allow BGE to manage O&M escalation at a rate slower than the rate of inflation during its MRP.[194] Accordingly, he recommended adjusting the inflation component of non-labor O&M expense during the MRP to reflect current published independent economists' projections of future Consumer Price Index ("CPI") growth.[195] Specifically, Mr. Gorman argued that an MRP average inflation rate of 2.0 percent should be used, representing a 20 percent decrease in inflation relative to BGE's inflation escalator.[196] He stated that this adjustment would result in approximately a $1.2 million reduction to electric operations and a $0.6 million reduction to gas operations.[197]

121. OPC witness Effron also testified against BGE's non-labor O&M inflation factor, arguing that the Company's forecast of 2.5 percent per year for the duration of the MRP is not reasonable given that the actual inflation rate in the second quarter of 2020 was negative and recent forecasts are projecting reduced levels of inflation in the near

[193] *Id*. at 22.
[194] *Id*.
[195] *Id*. at 23.
[196] *Id*.
[197] *Id*. at 24.

future.[198] In particular, Mr. Effron cited the May 2020 IHS forecast, which projects increases for the Gross Domestic Product ("GDP") Deflator of 1.0 percent in 2020, 0.6 percent in 2021, 0.5 percent, in 2022, and 0.6 percent in 2023.[199] He recommended that these figures be substituted for BGE's 2.5 percent inflation factor to project non-labor O&M expense over the course of the MRP.

122. BGE opposed the recommendations of DOD and OPC.[200] Regarding OPC's recommendation, BGE witness Vahos argued that Mr. Effron ignored in his calculations that the total O&M compound annual growth rate in the MRP is 0.5 percent. He asserted that if Mr. Effron's recommendations were accepted, BGE's O&M budget would be reduced by nearly $55 million, resulting in a "0% inflation trend for overall O&M in the [MRP]."[201] Additionally, Mr. Vahos argued that the 2020 non-labor O&M expense included in BGE's budget was not adjusted by an inflation factor, as it is BGE's policy to begin reflecting any O&M inflation beginning with the *second* year of the budget, not in the current year.[202] Mr. Vahos therefore argued that Mr. Effron's analysis mistakenly began by applying his inflation adjustment in the year 2020 rather than 2021.

123. Regarding DOD's analysis, Mr. Vahos argued that DOD witness Gorman's recommendation of 2.0 percent, a number much closer to BGE's calculation utilizing IHS Consumer Price Index rates, highlighted the unreasonableness of OPC's position.[203] Mr. Vahos also stated that as of the September 2020 update, the CPI Index for the Baltimore-

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198 Effron Direct at 18.
199 *Id*. at 19.
200 Vahos Rebuttal at 40.
201 *Id*. at 41.
202 *Id*. at 42.
203 *Id*. at 43.

Columbia-Towson region shows inflation rates to be 2.8 percent, 2.5 percent, and 1.8 percent for 2021, 2022, and 2023, respectively, which "clearly supports the reasonableness of the 2.5% inflation rate assumption reflected in the Company's [MRP]."[204] Mr. Vahos testified that the Commission has previously found that a historical CPI is a reasonable inflation factor for use in ratemaking and an appropriate proxy to be used for a rate effective period.[205] Finally, Mr. Vahos claimed that customers will be held harmless for any significant disparities between revenues and costs to the detriment of customers, which would appropriately be addressed in the annual informational filing and reconciliation processes.

124. In his Surrebuttal Testimony, Mr. Effron criticized BGE's argument regarding the Company's 0.5 percent compound annual growth rate, asserting: "The fact that costs are not escalating in a particular area (or areas) is not a valid reason to allow excessive escalation of expenses in other areas."[206] Mr. Effron also changed his recommendation to rely on the IHS CPI Baltimore/Towson Forecast, noting that the Commission has used this CPI as an applicable measure of inflation in past cases.[207]

125. For DOD, witness Gorman argued that an inflation rate that represents a consensus projection of independent economists' forecasts of future inflation is more appropriate for an MRP than BGE's historical inflation rate.[208]

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[204] *Id*. at 44.
[205] *Id*.
[206] Effron Surrebuttal at 9.
[207] *Id*. at 10.
[208] Gorman Surrebuttal at 13.

Commission Decision

126. In Order No. 88975, the Commission approved an inflation adjustment proposed by BGE to be applied to historical non-labor O&M costs.[209] The inflation adjustment approved by the Commission was based upon a historical five-year average of the Baltimore-Columbia-Towson region CPI, which the Commission found "…was an appropriate proxy for the rate of inflation for the rate effective period."[210] Similarly, in the present case, the Commission finds that BGE's 2.5 percent per year inflation forecast derived from the IHS Consumer Price Index represents a reasonable proxy for the rate of inflation to be used in the MRP. BGE's submission of the September 2020 update to the CPI Index for the Baltimore-Columbia-Towson region also demonstrates that the Company's 2.5 percent per year inflation forecast is reasonable, given that it lies between the low (1.8 percent) and the high (2.8 percent) of that three-year forecast for 2021 through 2023. To the extent that BGE has overestimated the inflation rate, customers will be held harmless, as witness Vahos testified. If there is a significant disparity between revenues and costs to the detriment of customers, that issue will be addressed in the annual informational filing and reconciliation processes.

9. Customer Additions – New Business

127. BGE's New Business – Electric category includes the capital to engineer, design, and install infrastructure to support new electric services to residential, commercial, and industrial customers.[211]

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[209] Case No. 9484, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to Its Gas Base Rates*, Order No. 88975 (Jan. 4, 2019).

[210] Order No. 88975 at 25.

[211] Biagiotti Rebuttal at 4.

128. OPC witness Alvarez asserted that BGE's proposed forecasted New Business – Electric budget increase from $45.7 million annually during 2015-2018 to $62.4 million annually from 2019-2023 is overstated because of the economic slowdown resulting from the COVID-19 pandemic.[212] Mr. Alvarez testified that reductions in economic activity and economic development resulting from the pandemic-related recession make BGE's forecasted new business connections "highly unlikely."[213] He recommended instead that BGE's budget be reduced to the average of the 2015-2018 period as a baseline, with a 2.5 percent inflation adder.

129. BGE witness Biagiotti criticized OPC's recommendation to base customer additions on historical average, arguing that new business service requests can vary significantly from year to year. He testified that the more accurate methodology, used by BGE, is to start with historical work volumes and then adjust for known large commercial and residential developments, and further adjust based on predicted economic activity.[214]

130. Mr. Biagiotti testified that BGE's staff meets on a day-to-day basis with commercial and residential developers to forecast the needs of its customers and to gauge the new load BGE will have to reliably serve. Regarding future economic activity, he testified that the developers "continue to be very optimistic about their development expectations and forecasts over the next several years."[215] Additionally, Mr. Biagiotti argued that Mr. Alvarez failed to account for certain large commercial and residential

[212] Alvarez / Stephens Direct at 50.
[213] *Id*.
[214] Biagiotti Rebuttal at 5.
[215] Hr'g Tr. at 248 (Biagiotti).

developments that require significant infrastructure and capital investment, including the continued expansion of Tradepoint Atlantic and Port Covington. Mr. Biagiotti argued that if BGE used the 2015-2018 period as a baseline, BGE would have insufficient budget to support the large increase in economic activity that these types of projects will bring.[216] He further stated that BGE is obligated to plan for the needs of all of its customers, including new customers forecasted to require interconnection, and that OPC's recommendation ignores the realities of this obligation.

Commission Decision

131. The Commission rejects OPC's adjustment to BGE's forecasts of new business connections. As BGE witness Biagiotti testified, the Company has a statutory obligation to meet the needs of its customers, including new customers forecasted to require interconnection.[217] The Company's methodology for meeting this obligation to serve appears reasonable on this record. BGE examined historical work volumes, adjusted for known large commercial and residential developments—including the expansion of Tradepoint Atlantic and Port Covington—and further adjusted based on forecasted economic activity. OPC's alternative methodology of basing new customer additions on historical averages has not been demonstrated to be superior, given that business service requests may vary significantly from year to year.

F. Work Plans

132. BGE witness Vahos stated that BGE's work plans and budgets were developed using the same budgeting methodologies that the Company has used for its internal

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[216] Biagiotti Rebuttal at 5.
[217] *Id.*; Apte Rebuttal at 19-20.

financial planning for many years.[218] Specifically, BGE's expenditures are budgeted at a project level, which are comprised of budgeted amounts in various states of maturity, ranging from projects that will begin construction in the near term to initial budgets for projects that do not yet have a detailed design and will not begin field construction until later in the budget cycle.[219] BGE has included exhibits to the testimony of its witnesses describing more than 300 projects.[220]

133. BGE witness Apte presented the Company's MRP-period electric reliability and strategic projects work plans and budget. He testified that BGE forecasts capital investment of $619.6 million for its long-term, grid and future planning investments that fall under the purview of its Technical Services division over the three-year MRP period.[221] He stated that these budgets cover capital investments related to Capacity Expansion – Distribution, Facilities Relocation – Distribution, Facilities Relocation – Gas, System Performance – Distribution, System Performance – Substation, and System Performance – Protection and Control.[222] Mr. Apte testified that these categories address the development and implementation of long-term, strategic reliability improvement plans.[223] He additionally contended that they are necessary for BGE to continue providing safe and reliable electric and gas distribution service, including BGE's

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[218] Vahos Direct Part 2at 17.
[219] *Id*.
[220] *Id*.
[221] Apte Direct at 2.
[222] *Id*. at 4.
[223] *Id*. at 5.

mandatory electric reliability standards.[224] BGE presented testimony regarding the following work plans: Technical Services; Capacity Performance; System Performance-Distribution; System Performance-Substation; Electric Distribution Capital; BGE New Business; Gas Distribution Capital; Customer Operations; and Non-Operating Capital.

1. Information Technology

134. OPC witness Larkin-Connolly recommended that the Commission disallow or reduce five BGE capital IT projects, resulting in a downward adjustment of BGE's IT Capital budget by $90 million, or approximately 40 percent, from the MRP period and $4 million from the 2020 bridge year.[225] He criticized BGE's IT projects for being insufficiently vague, noting for example, that BGE stated that project 66379 "holds the baseline funding for the yet to be designed IT project."[226] Mr. Larkin-Connolly concluded that it would be inappropriate to pre-approve funding for this project "when there is no proposed work yet attached to it."[227] Similarly, he argued that the Commission should exclude the proposed budget for years 2022 and 2023 for project 64713, arguing that it was insufficiently supported.[228]

135. BGE witness Vahos disagreed that the Company failed to provide adequate detail of its IT projects and his Rebuttal testimony provided additional detail addressing the

[224] BGE notes that in the context of its annual electric reliability reports, the Commission found that BGE's proposed reliability standards "strike a reasonable balance between maintaining and improving reliability, and the costs for that maintenance and improvement." BGE Brief at 27, n. 114 (citing Case No. 9353); Order No. 89056 (March 6, 2019) at 21.

[225] Those five Capital IT projects are: 64713: EU Digital Program - 2020; 60727: Pass Through - Capital IT; 66379: IT Projects; 64690: BGE PC 44 Rate Pilots; and 64692: Supplier Consolidated Billing - Case 9461.

[226] Larkin-Connolly Surrebuttal at 32l; *see also* Hr'g Tr. at 459, 461 (Vahos).

[227] Larkin-Connolly Surrebuttal at 33.

[228] Larkin-Connolly Direct at 55; Larkin-Connolly Surrebuttal at 31.

projects.[229] He argued that BGE has a legitimate business interest in ensuring "that its technologies remain current and secure and to invest in new technologies and functions that will benefit and improve the customer experience."[230] Additionally, he testified that BGE has become increasingly reliant on technology to deliver customer services like the Company's website and outage maps, SCADA, customer care and billing, and outage management systems.[231] He further asserted that BGE's IT systems represent core utility systems that must be maintained through continued investment.

2. Real Estate and Facilities Capital Investments

136. OPC witness Larkin-Connolly recommended the removal of $101 million from BGE's real estate and facilities capital budget during the MRP period, as well as the disallowance of $29 million for the 2020 Bridge Year, related to three capital real estate and facilities projects.[232] Project 60820 is a general facilities program that covers planned and emergent capital improvements or replacements of items such as HVAC, elevators, alarms, motors, chillers, boilers, and paving. Mr. Larkin-Connolly criticized BGE for providing few details, stating that the budget amounts appear to be placeholders for work that has not yet been identified.[233] Similarly, Project 60832 relates to renovations and replacements of HVAC, lighting, fire systems, and windows. Mr. Larkin-Connolly argued that the project lacked essential details. For both projects, he

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[229] *See* Vahos Rebuttal at 79-86; Hr'g Tr. at 460-61 (Vahos).
[230] Vahos Rebuttal at 79.
[231] *Id*. at 78.
[232] OPC's proposed capital reductions are related to following three Capital Real Estate and Facilities projects: 60832: Renovation Capital Life Cycle; 60820: Infrastructure-Capital Infrastructure Management Projects; and 66622: Office and Support Facilities program.
[233] Larkin-Connolly Surrebuttal at 41.

recommended that the Commission limit BGE's budget to align with the historic level, adjusted for inflation.[234]

137. BGE witness Vahos opposed OPC's recommendations, arguing that the facilities and real estate identified for improvement are outdated and require capital investment and refurbishment.[235] In particular, he noted that many of BGE's buildings are 40 to 60 years old and contain outdated workspaces that require updating to make more efficient use of space and to improve the workplace environment.[236] Mr. Vahos disagreed that BGE has not provided sufficient detail of the projects, noting that the Company provided lists of properties that BGE is actively seeking to work on, or is currently working on, such as the Perry Hall Service Center and BGE's Spring Gardens campus.[237]

3. Training Capital Investments

138. OPC witness Larkin-Connolly argued that virtual reality training is an "experimental" concept, and costs associated with such training should be disallowed. Project 60127 involves work to develop training simulations using virtual reality technologies to be used in several of the Company's business lines. Mr. Larkin-Connolly recommended exclusion of this program "because "[t]he potential for virtual reality to replace in-person training is an experimental concept that should not be borne by ratepayers."[238] Similarly, Mr. Larkin-Connolly criticized Project 61568, regarding innovation capital, because the program lacked sufficient detail and because it exceeded

[234] *Id*.
[235] Vahos Rebuttal at 88.
[236] *Id*. at 89.
[237] Hr'g Tr. at 463 (Vahos).
[238] Larkin-Connolly Direct at 65.

its three-year average historical spend.[239] He recommended that this project be adjusted down to align with historic levels.[240]

139. BGE witness Vahos disagreed with OPC's recommendation, stating that "BGE views VR as practical training because skills developed in a realistic virtual environment transfer to the real environment."[241] Mr. Vahos further asserted that virtual reality allows BGE to complement its classroom training by using technology that provides employees with training experience "that would be impossible or unsafe to recreate in the real world."[242] He stated that employees can "put on a headset and instantly share a virtual workspace allowing them to master tasks through repetition, building muscle memory with no additional cost of travel, work productivity, or in-person training."[243] Regarding Project 61568, Mr. Vahos disagreed that BGE should limit investment in innovation to historical spend, asserting that "History is not necessarily indicative of future levels of innovation funding needs."[244]

4. Electric Distribution Capital Work plan

BGE

140. For the three-year MRP period, BGE proposes to spend $705.3 million in capital investments for programs under its Electric Distribution division. Those programs are intended to support the safe and reliable operations and maintenance of the electric

[239] *Id*. at 69; Larkin-Connolly Surrebuttal at 46.
[240] Larkin-Connolly Surrebuttal at 46.
[241] Vahos Rebuttal at 93.
[242] *Id*.
[243] *Id*.
[244] *Id*.

distribution system, as well as new connections for both electric and gas service.[245] BGE witness Biagiotti testified that BGE's capital Electric Distribution budget is driven primarily by reliability, load growth, weather, and safety.[246]

OPC

141. OPC witnesses Alvarez and Stephens testified that several of the programs in BGE's electric capital plan lacked sufficient support regarding need and cost effectiveness. Mr. Alvarez also argued that although grid investment by U.S. investor-owned utilities has grown dramatically over the last several years, the reliability of U.S. investor-owned utilities has declined, as measured by System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI").[247] He asserted that grid reliability is governed by the law of diminishing returns and that because of capital bias, investor-owned utilities like BGE possess an incentive to invest beyond the point of diminishing returns, where the cost of the investment exceeds its benefit.[248] Mr. Alvarez testified: "Today, BGE is likely approaching, at, or beyond the point of diminishing return for reliability-related grid investments."[249] He recommended that many of BGE's programs be disallowed or curtailed.[250]

142. Mr. Stephens testified that BGE's proposed capacity expansion budgets are more than triple historical levels, despite falling system demand, and recommended significant

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245 Biagiotti Direct at 1-3.
246 *Id*. at 11-13.
247 Alvarez / Stephens Direct at 12.
248 *Id*. at 12-13.
249 *Id*. at 15.
250 *Id*. at 8-9.

reductions in capacity expansion capital.[251] Mr. Stephens also critiqued BGE's lack of rigor in capacity expansion project justifications generally. In particular, he criticized BGE's lack of risk reduction quantification—arguing that the Company's failure to quantify the level of risk reduced per dollar has led to a planning and spending approach where any risk reduction is worth a capital investment. As a consequence, Mr. Stephens recommended that BGE abandon multiple projects that offer the worst risk reduction-to-cost ratios. He further proposed that BGE's capacity expansion budget be limited to historical levels, adjusted for inflation.[252]

143. Mr. Stephens argued that four electric capital programs included in BGE's MRP lack sufficient support, do not meet industry standards, and will not improve reliability to the extent required to justify their costs. Those four electric capital programs are BGE's 4kV replacement program, substation perimeter security program, substation transformer replacement program, and planned cable replacement program. Those programs are described in the sections below.

BGE Rebuttal

144. On rebuttal, BGE witness Apte argued that OPC erred in arguing that grid investment leads to diminishing returns.[253] In particular, Mr. Apte criticized Mr. Alvarez for inferring that the only two drivers of distribution assets are peak demand growth and reliability. Mr. Apte asserted that Mr. Alvarez failed to consider the numerous other drivers of BGE's grid investment, including grid modernization, management of aging infrastructure, smart meter deployment, capacity expansion due to economic growth and

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[251] *Id*. at 35.
[252] *Id*. at 8 and 35.
[253] *Id*. at 3.

redevelopment, and distributed energy resource ("DER") integration. Mr. Apte further argued that Mr. Alvarez erred by failing to recognize that in 2015, BGE changed how its SAIFI and SAIDI metrics were reported, and he thereby underestimated the benefit of BGE's reliability spending.[254] Mr. Apte further contended that OPC's proposed shift to a reactive, versus a proactive replacement strategy, would limit BGE's ability to mitigate outages due to equipment failures that are entirely preventable through prudent asset management.

145. BGE witness Vahos asserted that the work plans it provided to the Commission were not developed specifically for the MRP, but rather were developed prior to the Commission's decision to proceed with a pilot MRP, in order for BGE to meet its regulatory requirements and the expectation of its customers.[255] Mr. Vahos also stated that the total budgeted capital expenditures in each of the MRP years is lower than its 2019 capital levels, and that the MRP operational and maintenance ("O&M") costs reflect a 0.5 percent growth rate over the 2021-2023 period as compared to 2019.[256] Mr. Vahos argued that BGE "is doing as much as it can with as little as it can,"[257] and contended that accepting OPC's recommendation that BGE could not file for recovery of certain investments for up to four years after they are made "would subject the Company to more regulatory lag than if we were operating in a historical test year structure."[258] He further stated that accepting OPC's position would place BGE in the precarious position

[254] *Id*. at 4. Mr. Apte testified that using his corrected trend analysis, BGE has improved SAIDI by 46 percent and SAIFI by 20 percent since 2012. *Id*. at 5.

[255] BGE Ex. 22a, Vahos Rebuttal at 10:4-9; BGE Ex. 5, Case Rebuttal at 3:5-6.

[256] BGE Ex. 4, Case Direct at 11; BGE Ex. 22a, Vahos Rebuttal at 5.

[257] BGE Ex. 22a, Vahos Rebuttal at 8:23-24.

[258] Vahos Rebuttal at 5.

of choosing to either pause important infrastructure projects or to finance over $1 billion of capital, and carry that debt over several years with no opportunity of starting cost recovery until 2024.[259] That result could jeopardize BGE's achievement of the reliability goals set by the Commission, in Mr. Vahos's opinion.

a. 4 kV Elimination

146. BGE states that its System Performance – Distribution category is responsible for enhancing the reliability of its electric distribution system and that continued investments in system performance are necessary to ensure that BGE delivers high-level reliability performance for its customers. For the years 2021 through 2023, BGE's budget for this category ranges from approximately $82 to $84 million per year, and the budget is driven by programmatic work to improve reliability and replace BGE's aging infrastructure.[260] BGE witness Apte testified that although BGE has consistently delivered strong reliability performance, continued investment is necessary to maintain current levels of reliability and to meet tightening reliability standards.[261]

147. Mr. Apte testified that BGE's 4kV Elimination Program is particularly important to the Company meeting reliability goals. Mr. Apte stated that BGE has proposed to invest approximately $25 million in capital expenditures per year under this program.[262] The program is designed to retire BGE's legacy 4kV system equipment, by upgrading 4kV infrastructure to modern 13kV standards. Mr. Apte testified that this conversion

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[259] *Id*.

[260] Apte Direct at 14.

[261] *Id*. at 12.

[262] *Id*. at 14.

program will provide reliability, operational, and safety benefits.[263] Additionally, he contended that transitioning away from 4kV will bring environmental benefits, such as creating a smarter grid that can facilitate customer interest in a greater array of offerings, such as rooftop solar.

OPC

148. OPC witness Stephens recommended elimination of BGE's 4kV program. Mr. Stephens testified that the costs of BGE's 4kV program exceed its benefits.[264] Supporting that contention, he stated that "4kV conversion costs are high, and shared by all BGE customers, [yet] each 4kV line may only serve a few hundred customers."[265] He acknowledged that where a utility needs to increase a 4kV line's capacity to accommodate growing loads, "conversion of the line from 4kV to 13kV is one of the least costly ways to do so."[266] However, Mr. Stephens testified that BGE admits none of the 4kV conversion projects proposed in this case are intended to prevent overloading.

149. Mr. Stephens also challenged the ostensible benefits of 4kV conversion, arguing that BGE's 4kV system has been more reliable than its 13kV system; that automation, and remote monitoring and control are available for 4kV equipment in addition to 13kV; that "4kV lines are no less able to accommodate rooftop solar … than any other voltage line"; and that no safety incident data in this proceeding indicates that 4kV lines are less safe than BGE's 13kV lines.[267] For these reasons, Mr. Stephens recommended that the

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[263] *Id*.
[264] Alvarez / Stephens Direct at 20.
[265] *Id*. at 18.
[266] *Id*.
[267] *Id*. at 19-20.

Commission disallow all 4kV capital spending in 2019 and 2020, and eliminate the program in BGE's electric distribution plan for 2021 through 2023.[268]

Staff

150. Staff witness Dererie supported inclusion of BGE's 4kV conversion program. She testified that BGE has been actively working to retire its 4kV infrastructure over the last few decades and expects to complete conversions to 13kV by the end of 2028.[269] She also noted that the typical useful life of a 4kV substation is 60 years, and that eight of the nine 4kV substations still in operation are at least 70 years old. Ms. Dererie contended that installation of the new 13kV equipment would allow for safer, more modern grid equipment that would facilitate the installation of distribution automation, the reduction of outage durations, and improved customer options such as a higher level of rooftop solar system installations.[270] Staff expressed concern with OPC's recommendation to discontinue the conversion program, noting that it might violate State policy to remove the benefits of the program from the underserved sections of Baltimore City.[271]

151. Based upon the benefits, Staff supported the continuation of the conversion program through the MRP period.[272]

BGE Rebuttal

152. Mr. Apte opposed OPC's recommendation to eliminate BGE's 4kV program. He asserted that OPC's position ignores the fact that 4kV conversions have been a consistent part of BGE's reliability plans for years and were included in BGE's plans submitted to

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[268] *Id*. at 21.
[269] Dererie Direct at 16.
[270] *Id*. at 16.
[271] Staff Initial Brief at 14-15, citing PUA § 7-213(b).
[272] Staff Initial Brief at 13.

the Commission in Case No. 9353, when the Commission set reliability standards for the Company.[273] Mr. Apte stated that the Commission has consistently accepted 4kV conversions in BGE's reliability plans and in prior rate cases as a way for BGE to meet mandatory electric reliability standards.[274] Mr. Apte criticized Mr. Stephens's conclusion that 4kV conversion should take place only for purposes of load growth, noting that numerous utilities nationwide have undertaken 4kV conversion efforts for many reasons other than load growth.[275] Mr. Apte additionally found fault with Mr. Stephens's assertion that the program is not cost-beneficial because BGE's 4kV system is only serving 30,883 customers, observing that BGE's 4kV circuits are located primarily in disadvantaged and underserved communities and that they should be entitled to the same benefits of a modernized grid as the rest of BGE's customers.[276] Finally, he presented evidence demonstrating a difference in the reliability experienced by its 4kV and 13kV feeders from 2015 to 2019.[277]

b. Planned Cable Replacement

153. BGE has two types of underground cable replacement—a reactive program that replaces failing cable, and a proactive or planned replacement program, which replaces fault-prone cable to improve reliability. BGE's planned cable replacement program replaces cable segments that have experienced cable faults and that also meet established criteria based on cable type.[278] BGE witness Apte testified that the Company's planned

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[273] Apte Rebuttal 22.
[274] *Id*. at 22.
[275] *Id*. at 23.
[276] *Id*. at 29.
[277] *Id*. at 24-25.
[278] *Id*. at 33.

cable replacement program has been a consistent part of BGE's reliability plans, including those presented in Case No. 9353, to achieve Commission-ordered reliability standards for years 2020 through 2023.[279]

OPC

154. OPC witness Stephens characterized BGE's planned cable replacement program as a "prospective asset replacement" program, given that it does not rely on objective justifications, does not meet industry standards, and "is intended to identify types of cable exhibiting certain failure rates, and then proceeds to replace 100% of that cable type over time regardless of section-specific performance."[280] He argued that the program "is essentially trying to predict which cable sections are going to fail regardless of historical failure rates."[281] Accordingly, Mr. Stephens recommended that this program be discontinued immediately and that the Commission disallow capital spending in 2019 and 2020 and in the 2021-2023 capital plan.[282]

Staff

155. Staff witness Dererie testified that BGE's internal underground cable replacement guidelines have been in place since 2003, and all proposed cable replacement projects in the MRP met this Company standard.[283] She testified that Staff has no objection to BGE's planned cable replacement program. In response to OPC's criticism, Ms. Dererie

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279 *Id*. at 31.
280 Alvarez / Stephens Direct at 29.
281 *Id*. at 29.
282 *Id*. at 31. Mr. Stephens also recommended that BGE's budget for its Reactive Cable Replacement Program be increased, given that he found its criteria more objective. *Id*.
283 Dererie Direct at 16-17.

stated that OPC acknowledged it does not have any information indicating that BGE's cable replacement practices are not standard industry practices.[284]

BGE Rebuttal

156. Mr. Apte testified against OPC's recommendations, contending that BGE's planned cable replacement program facilitates removal of problematic un-jacketed cable from the Company's system, and the program has been a consistent part of BGE's reliability plans to meet the Commission-approved reliability standards in 2020 through 2023.[285] He criticized Mr. Stephens for recommending the removal of a significant portion of BGE's System Performance-Distribution Capital "with absolutely no discussion of how that would impact the Company's ability to achieve its reliability standards, nor the potential fines that BGE would be subject to for failure to meet those standards."[286] Mr. Apte further testified that BGE's cable replacement program contains numerous criteria beyond cable types that exhibit high fault rates, including number of failures, number of customers affected, critical customers affected, frequency of failure, and cost.[287]

c. Distribution Substation Security Program

157. BGE states that its System Performance – Substation capital budget category is responsible for improving the reliability and physical security of its substations, reducing fire-related risk, and complying with EPA regulations.[288] BGE witness Apte testified that spend in this category is driven significantly by substation security projects, which are

[284] Dererie Surrebuttal at 7.
[285] Apte Rebuttal at 31.
[286] *Id*. at 32.
[287] *Id*. at 32-33.
[288] Apte Direct at 15.

executed to improve the physical security at substations to promote the safety of BGE's customers and ensure the security and reliability of BGE's electric distribution system. For example, Mr. Apte stated that BGE is in the midst of a 10-year, $200 million program to upgrade the physical security of its distribution substations, which involves the installation of new anti-cut/anti-climb fencing, movement detectors, cameras, and remote monitoring.[289] Additionally, Mr. Apte stated that BGE proactively replaces substation transformer oil containment pits, transformers, and substation fire protection systems. BGE has allocated $67.4 million, $47.7 million, and $38.4 million for System Performance – Substation for each of the respective years of the MRP period.[290]

OPC

158. OPC witness Stephens testified that this program presented several problems. First, he observed that BGE's justification for the program—that the level of physical substation security that it will achieve is consistent with the North American Electric Reliability Corporation ("NERC's") standard for transmission substation security—is flawed, given that the standards for transmission substation security are not applicable to distribution substations.[291] Mr. Stephens noted that distribution substations serve significantly fewer customers than transmission substations. Second, Mr. Stephens argued that there are many methods of sabotaging a substation by means other than physical intrusion, such that "physical security improvements offer little in the way of risk reduction."[292] Third, BGE has not cited any incidents of service outages stemming

[289] *Id*. at 4.
[290] *Id*. at 5.
[291] Alvarez / Stephens Direct at 22-23.
[292] *Id*. at 22.

from distribution substation intrusions. Mr. Stephens concluded that BGE's program could not justify its cost, relative to its risk reduction, and recommended that the recovery of costs for all substation physical security upgrade capital spending in 2019 and 2020 be disallowed, and that substation physical security upgrade capital proposed in the electric distribution plan for 2021 through 2023 be eliminated.[293]

Staff

159. Staff witness Dererie agreed with BGE's need to protect its critical energy facilities as described in the MRP.[294] However, given the confidentiality requirements associated with security investments, she testified that it is difficult for Staff and the Commission to question or provide feedback on BGE's security investment plans in a rate case. Accordingly, Ms. Dererie testified that BGE should provide more granular details about its physical security investment costs and status, protection standards, and tiering, as well as metrics in its next scheduled cyber-security briefing with the Commission in 2022.

BGE Rebuttal

160. In his Rebuttal Testimony, BGE witness Apte stated that BGE has put forth well-balanced plans to ensure the security of critical infrastructure amid increasing trends of physical threats to the grid. He additionally stated that it is prudent management and in the best interest of all stakeholders to address threats when the Company is aware of them as opposed to leaving the system vulnerable. Regardless of the number of customers served by distribution substations, he argued that BGE has critical distribution facilities

[293] *Id*. at 24.
[294] Dererie Direct at 19.

that provide service to pumping stations, hospitals, federal, state and local government agencies, and military installations. Mr. Apte also rebutted Mr. Stephens's claim that investments in distribution substation security are not standard industry practice, stating that BGE's program is similar to that of many utilities.[295] Mr. Apte testified that BGE employs a robust process to determine whether physical security upgrades to a substation are warranted, including by conducting a technical assessment of its electric assets every three years to determine how critical they are to both the transmission and the distribution system.[296] He stated that as a result of this rigorous process, BGE is only upgrading 43 of 206 distribution substations, or approximately 21 percent.[297]

161. Regarding Staff witness Dererie's recommendation, Mr. Apte stated that BGE is willing to provide more granular details about its physical security investments in the Company's next scheduled cybersecurity briefing.[298]

d. Substation Transformer Replacement Program

BGE

162. BGE's Substation Transformer Replacement program is designed to replace aging distribution transformers to avoid failures that would affect reliability by targeting 130 transformers that are over 50 years old.[299] In its MRP, BGE plans to proactively replace two transformers in 2021, three in 2022, and four in 2023.[300]

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[295] Apte Rebuttal at 13. Mr. Apte stated that Xcel Energy, NextEra Energy, and Southern Company, each have a similar program to BGE's substation physical security program, including both transmission and distribution substations.
[296] Apte Rebuttal at 11.
[297] *Id*. at 12.
[298] *Id*. at 10.
[299] Apte Direct at 36.
[300] Dererie Surrebuttal at 9.

OPC

163. OPC witness Stephens criticized BGE's substation transformer replacement program as constituting "prospective asset replacement," meaning the replacement of assets that have zero book value but which are operating safely and reliably. Mr. Stephens asserted that "replacing equipment simply because it is old, when an objective justification for replacing it does not exist, is not appropriate."[301] He argued that assets should only be replaced based on objective criteria such as equipment test results, equipment inspection results, or historical outage failures. Mr. Stephens testified that BGE's proposed project 63038, "Proactive Distribution Substation Transformer Replacement," constitutes a prospective asset replacement program where BGE will replace transformers based on age and other subjective factors, which could "deprive customers of decades of useful life on transformers."[302] Mr. Stephens recommended that the Commission order BGE to immediately discontinue its prospective substation transformer replacement program and disallow all associated spending.[303]

Staff

164. Staff witness Dererie stated that she had no objection to BGE's proactive Substation Transformer Replacement program. She noted the difficulty involved in waiting for transformer failure as a driver for replacement, and that this might result in substations being out of a normal configuration until the replacement transformer is available.[304] She also testified that OPC was unable to present any evidence that indicates

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301 Alvarez / Stephens Direct at 24-25.
302 *Id*. at 27.
303 *Id*. at 28.
304 Dererie Direct at 23.

that proactively replacing distribution substations is not standard industry practice.[305]

BGE Rebuttal

165. BGE opposed OPC's recommendation to disallow BGE's 2020 investment in Distribution Substation Transformer Replacements and to discontinue these efforts going forward. Witness Apte testified that BGE has an aging fleet of distribution substation transformers that includes a significant number that are beyond their useful lives.[306] He observed that 130 transformers are over 50 years old. Nevertheless, Mr. Apte stated that BGE examines a comprehensive set of factors (including but not limited to age), to identify transformers that are at a higher risk of failure.[307] He also stated that in-service failures of transformers that have not been replaced can have negative impacts on BGE's equipment and distribution system.

e. Capacity Expansion Capital Reductions

BGE

166. BGE's Capacity Expansion – Distribution category includes the capital and O&M spend necessary to support load growth while ensuring that the Company operates a safe and reliable electric distribution system.[308] BGE witness Apte testified that work performed in this area is driven by customer-specific requirements, aggregate customer demand, established system planning criteria, regulatory standards, and industry

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[305] Dererie Surrebuttal at 8.

[306] Apte Rebuttal at 37-38.

[307] Mr. Apte testified that such factors include trending of dissolved gas analyses and other test results, corrective maintenance work order history, condition of solid or liquid insulation, design or parts obsolescence, industry and/or manufacturer information about failure risk, design and manufacturing standards at the time of manufacture, and BGE's recent failure history of same vintage and manufacturer transformers. *Id*. at 39.

[308] BGE Initial Brief at 30.

standards.[309] Spending in this category includes electric distribution infrastructure buildouts, as well as substation and circuit upgrades.

OPC

167. OPC witness Stephens argued that BGE's capacity expansion budget is excessive in relation to "falling system demand," and he recommended significant reductions in capacity expansion capital as a result.[310] Specifically, he asserted that BGE has proposed to triple its distribution capacity expansion capital spending budget, from an average of $18.2 million annually from 2015-2018 to an average of $57.1 million annually from 2019-2023.[311] He also argued that BGE's process for evaluating and selecting capacity expansion projects is "insufficiently rigorous" and lacks appropriate constraints, leading to the Company's approval of more capacity expansion projects than are needed for the provision of safe and reliable electric service.[312] In order to rectify these problems, he testified that BGE's capacity expansion budget should be significantly constrained. Specifically, with the exception of six projects[313] that Mr. Stephens found to be in customers' interest, he argued that BGE should be authorized to spend only its historical baseline, plus 2.5 percent inflation annually, "in the way BGE deems will maximize reliability risk reduction for the available budget."[314]

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[309] Apte Direct at 6.
[310] Alvarez/Stephens Direct at 35, 39, 50.
[311] *Id*. at 38-39.
[312] *Id*. at 38.
[313] Mr. Stephens found merit in the following six proposed capacity expansion projects: two projects to accommodate economic development underway (including Port Covington substation and circuits), two proposed CVR projects, and two proposed battery projects required by the Commission. *Id*. at 41.
[314] *Id*.

BGE Rebuttal

168. BGE witness Apte responded that BGE has a robust evaluation, delegation of authority, and approval process for funding capacity expansion projects, including extensive planning and evaluation by BGE's distribution planning team.[315] Mr. Apte disputed OPC's allegations that falling demand has obviated the need for capacity expansion, noting that system-wide falling or flat demand does not preclude areas of rapid growth that may necessitate increases in grid capacity.[316] In particular, Mr. Apte noted that BGE is experiencing significant redevelopment efforts requiring enhanced electric distribution infrastructure in its service territory, including the redevelopment of the Port Covington peninsula and the redevelopment of Tradepoint Atlantic.[317] Mr. Apte argued that as a regulated monopoly, BGE has an obligation to serve the electric distribution customers in its service territory and cannot ignore the infrastructure buildout necessary to support new and rapid load growth at Tradepoint Atlantic and Port Covington.[318]

f. Underground Fault Detector Program

169. In its Underground Fault Detector program, BGE has proposed to install a new smart fault detection system for its underground feeders, similar to the systems that it uses for overhead distribution feeders.

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[315] Apte Rebuttal at 14. For example, Mr. Apte testified that BGE assesses solutions including phase balancing, distribution automation, feeder switching, and capacitor installations before considering more significant construction projects. *Id*. at 14-15.

[316] *Id*. at 20.

[317] Apte Direct at 10.

[318] Apte Rebuttal at 20.

170. Because this program is a developmental project, Staff witness Dererie testified that it should be further evaluated before it is widely deployed. She recommended that the program be classified as a pilot program and full-scale deployment approved only after BGE, through reporting in Case No. 9353, demonstrates that there is no risk to full deployment and that reliability benefits will be achieved.[319] During the evidentiary hearing, Ms. Dererie amended her testimony to recommend that the costs of the program be placed in a regulatory asset, with the costs to be recovered only after a showing that the benefits have been achieved.[320]

5. Gas Distribution Capital Work Plan

171. BGE witness Burton presented the Company's work plans and budgets for the gas business components of the proposed MRP. Mr. Burton testified that for the duration of the MRP, BGE forecasts its total capital investments in the gas business areas covered by his testimony to be $918.2 million.[321] He stated that the projected capital investments for the MRP period are relatively steady as compared to historical investment levels, "with a minor fluctuation of about 10% in 2022" due to a transmission line replacement project planned for construction in that year."[322] He further testified that the predominant components of BGE's work plans over the next three years involve the continuation of projects to replace aging infrastructure, including STRIDE work, in addition to work that is required to maintain compliance with regulations and engineering standards.

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[319] Dererie Direct at 2-3.
[320] Hr'g Tr. at 978-79, 982-83 (Dererie).
[321] Burton Direct at 3.
[322] *Id*. at 17.

172. Mr. Burton testified that BGE's Gas Division engages in a systematic capital planning process by evaluating long-term goals, historical patterns, and anticipated future requirements.[323] As part of this process, the Gas Division evaluates BGE's infrastructure and activities in relation to (i) how to meet regulatory and code requirements and commitments, (ii) system performance needs, (including safety and reliability related activities, and aging infrastructure replacement efforts), (iii) capacity expansion, (including load growth), and (iv) system maintenance activities.[324] Overall, Mr. Burton testified that BGE expects a "flat trend over the next three years" because "the replacement programs and other compliance activities are at steady state."[325]

OPC

173. OPC witness Larkin-Connolly testified regarding BGE's gas capital spending, including actual plant additions made through the end of the 2019 historic test year, as well as the budgeted 2020 bridge year additions, and the three-year budgeted additions that make up the MRP. Mr. Larkin-Connolly argued that a number of the projects included in BGE's gas capital plan significantly exceeded the Company's recent historic spending and lacked explanation or justification for the level of increased cost.[326] He evaluated the projects by comparing the average three-year MRP spend to the 2019 test year levels, and he scrutinized the project for possible adjustment if the MRP was more than 108 percent of the test year spend.[327] For several projects, he recommended setting the project budgets at amounts commensurate with the 2019 historic test year levels,

[323] *Id*. at 15.
[324] *Id*. at 15.
[325] *Id*. at 17.
[326] Larkin-Connolly Direct at 4-5.
[327] *Id*. at 24.

adjusted for inflation. Mr. Larkin-Connolly criticized what he referred to as "program projects," where "budget amounts are overly speculative and not based on actual identified work."[328] In other cases, he stated that the projects simply appeared to be a " 'plug' or placeholder to house a budget amount the Company wishes to include in the MRP."[329] He argued that approving these budgets could create an incentive structure that promotes over-investment, as BGE would want to meet these "*de facto* spend targets" in order to avoid reimbursing customers during the reconciliation.[330]

174. In order to prevent these problems, Mr. Larkin-Connolly testified that the Commission should only approve capital additions that fit into one of the following categories: (i) a discrete project with a clear scope of work; (ii) a program project with MRP budgets that align closely with historical spend; (iii) an existing program project with budgets outside of historical spend and a clear justification for the increase; or (iv) a new program project with a proposed set of work or activities that is shown to be necessary and not covered under another project.[331]

<u>*BGE Rebuttal*</u>

175. BGE witness Vahos disputed OPC's claims that the Company's gas projects were unsupported, testifying that they receive multiple levels of Company review and that BGE has presented significant details in this proceeding. He further testified that "some variance in year-over-year trends in individual Capital projects is very common given the

[328] *Id*. at 9.
[329] *Id*.
[330] *Id*. at 10.
[331] *Id*. at 12.

need to balance the work plan with overall costs and resources."[332] However, BGE manages its capital budget on an overall portfolio level, which has remained relatively stable. In fact, "BGE's average capital spend over the MRP period is 97% of the historical test year spend, which is clearly below the 108% test used by OPC witness Larkin-Connolly to evaluate and disallow Capital spend over both the Bridge Year and MRP period."[333]

176. BGE witness Vahos also denied that BGE had any incentive to overestimate budgets, stating that the Company is motivated to produce an accurate budget for both external reporting purposes and ratemaking design, and the nature of the reconciliation mechanisms further supports BGE's strong motivation to produce reasonable and accurate budgets.[334]

a. STRIDE Projects[335]

<u>*OPC*</u>

177. OPC recommended removing all STRIDE projects from the MRP, including the two STRIDE projects that were completed in 2020, as well as those STRIDE projects that BGE budgeted to complete in 2021-2023.[336] In his Direct testimony, OPC witness Larkin-Connolly recommended disallowance because the projects he reviewed were based on "budgeted amounts" rather than "actual expenses through a certain date."[337] He also argued that "BGE is attempting to circumvent ratepayer protections included in the

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[332] *Id*. at 12.
[333] *Id*. at 13.
[334] *Id*. at 15-16.
[335] This section addresses specific STRIDE projects included in BGE's work plans, as opposed to the mechanism to pay for such projects (either surcharge or MRP) discussed in Section III(A)(4)(a) above.
[336] Larkin-Connolly Direct at 21-22.
[337] *Id*. at 22.

STRIDE surcharge by including budgeted STRIDE additions in the MRP rate base."[338] However, Mr. Larkin-Connolly later clarified his testimony to state that he does not oppose including BGE's budgeted STRIDE projects for 2021-2023 in the MRP's base rates.[339] Mr. Larkin-Connolly also recommended excluding over $47 million from years 2020-2023 because this spend is related to BGE's non-STRIDE main replacement program that he characterized as an "attempt to circumvent STRIDE."[340]

BGE Rebuttal

178. In his Rebuttal testimony, BGE witness Burton testified that each of the programs that Mr. Larkin-Connolly seeks to remove from the MRP are important components of the Company's overall work plan and are needed to meet regulatory requirements and commitments, improve system performance and reliability, address capacity concerns, and continue to provide safe and reliable service for BGE's gas customers.

179. Regarding BGE's non-STRIDE main replacement program, BGE witness Burton testified that the project "focuses on large-scale main replacement work that . . . is not included as part of the annual STRIDE project list submitted for Commission approval" and, therefore, "by default, this work is not eligible for STRIDE surcharge recovery."[341] Mr. Burton further stated that the project accelerates the retirement of BGE's low-pressure system, which has been raised as a concern nationally among gas utilities and regulators.

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[338] *Id*. at 5.
[339] Larkin-Connolly Surrebuttal at 14; Hr'g Tr. at 826 (Larkin-Connolly).
[340] Larkin-Connolly Direct at 39.
[341] Burton Rebuttal at 8.

b. Pay It Forward

180. BGE proposed the Pay It Forward pilot program in November 2019, which would allow BGE to use expected revenues from future gas customers to offset current customer costs for new main extension projects to connect new residential, commercial, and industrial customers.[342] On May 28, 2020, the Commission opened a docket to investigate whether to approve the pilot program and set a procedural schedule with evidentiary hearings to begin on April 22, 2021.[343]

181. In the present rate case, OPC witness Larkin-Connolly recommended that the entire $14.0 million budget for this program be removed from the MRP, arguing that it requires too many speculative assumptions, such as the timing of when, or if, the program will be approved, or how many new conversions will occur as a result of the new extension policy.[344]

182. BGE witness Biagiotti testified that he agrees that the budget for the Pay It Forward program should be adjusted, since the program has not yet been approved.[345] Accordingly, he removed the program's budget for 2020 and one half of the budget for 2021. However, he objected to removing the entire budget since the program could require funding beginning in the second half of 2021. Regarding the possibility of disapproval in Case No. 9646, Mr. Biagiotti stated "BGE would update the Commission

[342] *Id*. at 6.
[343] Order No. 89572, *Baltimore Gas and Electric Company's "Pay It Forward" Pilot Program*, Case No. 9646, at 4 (June 30, 2020).
[344] Larkin-Connolly Direct at 30.
[345] Biagiotti Rebuttal at 7.

as part of the annual project listing and informational filing requirements of the MRP consistent with all other project updates."[346]

c. System Performance Gas Budget

BGE

183. BGE's System Performance Gas projects are designed to maintain or improve the safety and reliability of the gas distribution system primarily through replacing or upgrading existing assets.[347] The general goals of these investments are to reduce risks, including by: (i) reducing leaks and thereby improving safety and lessening environmental impacts, (ii) reducing and avoiding unplanned customer interruptions, and (iii) reducing other risks such as over-pressurization, excavation damage, or natural causes such as flooding. BGE's long-term strategies to achieve those goals include eliminating cast iron and bare steel mains; eliminating low-pressure systems; reducing the population of metallic services and replacing them with modern high-density polyethylene services; increasing system connectivity to improve reliability; and replacement and modernization of gate station, gas plant, and other operational equipment needed to maintain gas supply.[348]

OPC

184. OPC witness Larkin-Connolly recommended reduction to Project 58034: Non-STRIDE Corrective Maintenance Gas Main Replacements, based on his opinion that the increase in spend on STRIDE-eligible mains outside of STRIDE represented an attempt to circumvent the 48-mile annual replacement rate set by the Commission in Case No.

[346] *Id*. at 8.
[347] Burton Direct at 3.
[348] *Id*. at 3.

9468.[349] He also proposed removing Project 58539: Upgrade for Gas Transmission In-Line Inspection because the budget appears to be a placeholder amount for a potential project in 2023 that has not yet been identified.[350]

BGE Rebuttal

185. BGE witness Burton testified that BGE is reliant on Project 58034 to accelerate cast iron and bare steel main replacement work *and* to facilitate additional low-pressure system reductions beyond STRIDE.[351] He further stated that since the inception of the STRIDE program, BGE has always performed similar asset replacement work outside of STRIDE, without issue.[352] Mr. Burton stated that although the Commission's order in Case No. 9468 limits BGE's ability to recover costs through the STRIDE surcharge, there is no limit for replacement work outside of STRIDE.[353] Regarding Project 58539, Mr. Burton asserted that, because the MRP is a forward-looking plan, BGE anticipates the need to install more infrastructure to support in-line inspection of transmission mains and has forecasted these needs in its MRP.[354] He characterized as "unreasonable" the level of specificity Mr. Larkin seeks for all of the jobs within this project that will take place in 2023.

Staff

186. Staff witness Clementson testified that he does not have any issues with the

[349] Larkin-Connolly Surrebuttal at 25-26.
[350] Larkin-Connolly Direct at 43.
[351] Burton Rebuttal at 7-9.
[352] *Id*. at 15.
[353] *Id*. at 14; *see also* Hr'g Tr. at 849-51 (Larkin-Connolly).
[354] Burton Rebuttal at 18.

programs that BGE has proposed.[355]

d. Gas Capacity Expansion Budget

BGE

187. Gas capacity expansion "ensures system capacity and reliability for gas customers in all weather conditions down to design day conditions."[356] It "[a]ddresses inadequate capacity on the gas distribution and transmission systems as forecasted in the gas system model or experienced in physical system data.[357] BGE's Gas Capacity Expansion program includes all projects implemented to address areas with inadequate capacity on the gas transmission and distribution systems.

OPC

188. In his Direct Testimony, OPC witness Larkin-Connolly recommended disallowance of portions of several projects due to a lack of alignment with historic spend levels and a paucity of supporting information. However, in his Surrebuttal Testimony, Mr. Larkin-Connolly recommended that only one project—Project 60701: Reinforcement – Gas System Reinforcements—be reduced to align with historical spend.[358]

Staff

189. Staff witness Clementson reviewed the projects proposed in this category and does not recommend disallowance of any specific projects or otherwise object to them.[359]

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[355] Clementson Direct at 15.
[356] Burton Direct at 18.
[357] Clementson Direct at 15.
[358] Larkin-Connolly Surrebuttal at 28.
[359] Clementson Direct at 15-16.

BGE Rebuttal

190. BGE opposed OPC's recommendation. BGE witness Burton argued that work in this project fluctuates as gas resources are balanced and system needs vary year to year in the overall MRP gas capital plan.[360] He further testified that the Gas System Reinforcement project is critical to ensure that the gas system can maintain adequate capacity and pressures to supply gas customers through all times of the year. Finally, Mr. Burton asserted that work in this project is necessary to support BGE's efforts to perform low-pressure conversion and other STRIDE-related work.

e. Tools

191. BGE's Tools category includes the capital and O&M budget needed to purchase new and replacement tools that enable electric and gas field crews to perform their construction, operation, and maintenance activities safely and efficiently.[361] BGE witness Biagiotti presents three projects in the "Tools" category of Capital, two of which are electric and one of which is gas.

192. OPC witness Larkin-Connolly testified that the Tools projects exceed his 108 percent threshold test.[362] Mr. Larkin-Connolly argued that BGE inappropriately relied on an increase in the use of tools for new trucks and trainee classes in 2020 as a justification for the entire three-year MRP. He also criticized the project's lack of detail or justification and argued that the budget amounts should be set at annual amounts in line with the 2019 historic test year levels.[363] BGE witnesses Vahos and Biagiotti opposed

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[360] Burton Rebuttal at 22-23.

[361] Biagiotti Rebuttal at 1-2.

[362] Larkin-Connolly Direct at 51.

[363] *Id*. at 53.

OPC's recommendation.[364]

193. Witness Biagiotti asserted that BGE's increased maintenance and replacement programs have necessitated additional hiring of employees, who will require the appropriate equipment in order to safely perform their work.[365] He stated that this expansion is expected to continue throughout the MRP period.

f. Fleet

194. Fleet projects include the purchase of shop equipment and mechanic tools used for maintaining the fleet vehicles.

195. OPC witness Larkin-Connolly identified certain Fleet Program Projects as exceeding his 108 percent threshold, and he recommended that one such project be adjusted to align with historic levels.[366]

196. BGE witness Vahos opposed OPC's recommendation, stating that BGE is modernizing its fleet shops, tools, and technology.[367] He argued that the increase in spend is driven by the need to ensure safety and productivity, given that many tools are "outdated, broken, missing, or worn." [368]

g. Other

197. OPC witness Larkin-Connolly stated that BGE includes 14 projects in its Other category, and he identified six of these projects as being program projects that lacked detail and were essentially placeholders.[369] Based on his 108 percent threshold test and

[364] Vahos Rebuttal at 86; Biagiotti Rebuttal at 2.
[365] Biagiotti Rebuttal at 2.
[366] Larkin-Connolly Direct at 59.
[367] Vahos Rebuttal at 86.
[368] *Id*.
[369] Larkin-Connolly Direct at 67.

further analysis, Mr. Larkin-Connolly identified three projects in the Other category for adjustment. For example, he referred to the category of "Other projects less than $1 million" as "a catch-all budget for the catch-all category," and criticized BGE's decision to double the category's budget without providing information to evaluate it.[370]

198. BGE witness Vahos stated that the Company did not initially provide information about this category because the MRP Pilot Order requires such detail only for capital expenditures greater than $1 million.[371] Mr. Vahos stated that this category includes projects such as Security Capital (correcting emergent issues), Smart Grid / Smart City Devices (evaluating new devices that operate over the AMI network); and Lab Upgrade (upgrading AMI test equipment).[372]

<u>Commission Decision</u>

199. The Commission finds the majority of BGE's work plans to be reasonable for purposes of setting BGE's revenue requirement for the MRP, subject to the extension of selected budget spending discussed below. However, the Commission is not pre-approving any particular work plan or project for purposes of prudency in this Order. As provided in the MRP Pilot Order: "The proposed project list and individual project costs would not be pre-approved by the Commission but would 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."[373] BGE expressed agreement with that principle, stating that "the Company is not asking the Commission to

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[370] *Id*. at 70.

[371] Vahos Direct at 97 (citing MRP Pilot Order at 23-24).

[372] Vahos Rebuttal at 98.

[373] MRP Pilot Order at 24 (internal citations omitted).

approve the specific work plans (or specific projects) that the Company intends to execute during the [MRP] period."[374] Many of the issues that OPC raised in this proceeding, including whether particular projects will ultimately benefit ratepayers, and whether actual project costs are excessive, will become ripe for prudency review during the reconciliation process.

200. Nevertheless, the Commission will disallow certain cost projections at this stage. Specifically, as discussed above, the Commission directs BGE to eliminate the budgets for Contingencies (Capital Spending) and Contingencies (O&M). Additionally, the Commission directs BGE to eliminate the budget for unidentified shared costs for both gas and electric as unsupported in the record.

201. The Commission rejects OPC's request to eliminate, disallow costs from, or reduce several of the programs criticized by OPC, but does extend the budget spending period for some programs. In particular, the Commission elects not to eliminate BGE's 4kV conversion program or disallow spending. The program has been a consistent part of BGE's reliability plans for years, and it is integral to the Company's reliability plans to meet standards set in Case No. 9353. Reliability data indicates an improvement in the reliability experienced by BGE's 4kV and 13kV feeders from 2015 to 2019.[375] BGE's planned cable replacement program also appears to be an important element of the

[374] BGE Initial Brief at 17. *See also* Hr'g Tr. at 495 (Vahos) ("[S]ince the prudency determination in the implementation order is actually happening in the reconciliation process … you aren't actually approving the work per se…. [Y]ou've left yourself that prudency determination on whether that was the right work or whether these rates were appropriate for that reconciliation step.").

[375] Apte Rebuttal at 24-25. For example, for reliability calculated during all-weather with planned outages excluded, the SAIFI of 4 kV feeders was 0.94 and SAIDI was 179 minutes while that of 13 kV feeders was 0.87 and 150 minutes, respectively.

Company's plan to achieve mandatory reliability standards. This program's spending during the rate effective period is discussed below.

202. Regarding its Distribution Substation Security Program, BGE is directed to provide more details of its distribution substation physical security investment costs and status, protection standards, and tiering as well as metrics in its next scheduled cyber-security briefing with the Commission in 2022.

203. The Commission rejects OPC's request to discontinue BGE's Substation Transformer Replacement Program. BGE demonstrated that a significant number of transformers are beyond their useful lives, and Staff testified that waiting for failure to replace the transformers can have negative impacts on BGE's equipment and distribution system.[376]

204. The Commission also rejects OPC's recommendation to significantly reduce BGE's capacity expansion budget. BGE has demonstrated an appropriate evaluation process for approving programs within that budget and shown that it must enhance electric distribution infrastructure to meet the needs of the redevelopment of the Port Covington peninsula and Tradepoint Atlantic.[377]

205. The Commission agrees with Staff witness Dererie that BGE's Underground Fault Detector program is in a developmental stage, and that BGE should recover the costs of the program only after it demonstrates that the benefits have been achieved. Accordingly, the program is approved as a pilot with full implantation subject to BGE's demonstration in a filing with the Commission that there are no risks to full-scale

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[376] Dererie Direct at 23.
[377] Apte Direct at 10.

deployment and that program benefits are being obtained as projected after the devices have been in place for a reasonable evaluation period. BGE is directed to place the costs of this program in a regulatory asset.

206. Based on the results of his 108 percent threshold criteria and further analysis, OPC witness Larkin-Connolly recommended that several project budgets be reduced from the increased or unsupported spending levels in BGE's MRP. The Commission rejects OPC's recommendation to disapprove these program increases based on Mr. Larkin-Connolly's criteria alone. Although it is helpful to scrutinize individual project budgets, BGE correctly notes that there may be variances in the year-to-year budgets of individual programs for a variety of reasons, and that the Company will balance the progress of those individual programs with the budget of the overall portfolio.[378] However, Mr. Larkin-Connolly's analysis, coupled with other considerations discussed herein, help inform the Commission's decision to slow the pace of certain BGE capital spending for the benefit of ratepayers, as described below.

207. The Commission rejects OPC's recommendation to remove particular STRIDE projects from BGE's budget. The Commission does not view any project as an attempt to circumvent STRIDE. BGE will continue to execute its five-year STRIDE plan, which was approved on May 30, 2018 through Order No. 88714.[379] Additionally, the Company shall pursue those projects enumerated in its 2021 Project List, which was approved by letter order on December 2, 2020.

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[378] As Mr. Burton stated, irrespective of the fluctuation of individual projects from year-to-year, the overall capital work across the Gas Executive categories averages within 4 percent of 2019 levels. Burton Rebuttal at 24-25.

[379] *See* Case No, 9468, *In the Matter of Baltimore Gas and Electric Company for Approval of a New Gas System Strategic Infrastructure Development and Enhancement Plan and Accompanying Cost Recovery Mechanism*.

208. Regarding BGE's Pay It Forward program, the Commission accepts BGE's proposal to fund the program beginning in the second half of 2021. As Mr. Biagiotti stated, the MRP process contains true-up procedures to manage budget changes over time. If the Commission does not approve the Pay It Forward program in Case No. 9646, BGE would remove funding in the program as part of its annual project listing and informational filings with the Commission required by the MRP. Additionally, BGE assumes the risk that any funding it has spent on the Pay It Forward program will be disallowed for imprudence or for a possible disapproval in Case No. 9646. The Commission expressly reserves its decision of the prudency of the Pay It Forward program, or any program contained in the MRP. Those decisions will be made at the end of the MRP during the prudency review.

209. The Commission rejects the recommendation to remove costs related to Non-STRIDE Corrective Maintenance Gas Main Replacements or Upgrade for Gas Transmission In-Line Inspection. In Case No. 9468, the Commission did not limit BGE's ability to replace cast iron and bare steel main outside of STRIDE beyond 48 miles per year. Nor did the Commission generally limit BGE's replacement work outside of STRIDE. The Commission also agrees with BGE that its needs concerning the installation of infrastructure to support in-line inspection of transmission mains in 2023 may change and that it is not required to provide complete specificity at this time. Finally, the Commission rejects the recommendation to reduce Project 60701: Reinforcement – Gas System Reinforcements to align with historical spend.

210. Irrespective of the value of individual work plans that BGE has proposed, the Commission is concerned that the magnitude of work plans included in the MRP—and

their pacing—will unduly burden BGE ratepayers at a time of economic stress. As discussed throughout this proceeding, the COVID-19 pandemic has imposed significant economic disruption upon Maryland ratepayers, many of whom are ill-prepared to endure the substantial rate increase BGE has proposed.[380] Yet BGE has filed a multitude of aggressive programs to expand its infrastructure, improve reliability, and enhance services. As OPC witness Roberto testified: "BGE's MRP continues an unrelenting pattern of increases in its annual revenue requirement, which the reconciliations authorized in the Pilot Order and as proposed within BGE's MRP could further exacerbate. My final observation regarding BGE's MRP is that, if adopted, it will introduce a significant risk of customer rate shock at its conclusion."[381] Certainly, BGE has a duty to provide reliable service—but the Commission finds that the breadth and pace of its work plans is ill-timed for the current economy.

211. Accordingly, the Commission concludes that BGE must reduce the financial impact to customers by reducing the speed of its spending. The Commission has selected a number of work plans that OPC identified as outliers relative to historic spend, or were otherwise unsupported in the record, and extended the OPC-identified accelerated or unsupported spending in those accounts from three years to five years. This approach recognizes the value that BGE has placed in these projects, and allows the company to review and prioritize its work plans within the guidance provided here. This approach also balances ratepayers' interest in avoiding excessive financial impacts.

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[380] *See* OPC Initial Brief at 5 (stating: "Our nation has been in the grip of a global pandemic that has no known end in sight, and is responsible for economic distress for a significant number of households and businesses.").

[381] Roberto Direct at 5.

212. BGE is directed to extend the spending timeframe or budgeted increases of the following work plan budgets from three years to five years: Electric: 4kV Elimination; Distribution Substation Security Program; Substation Transformer Replacement Program; and Planned Cable Replacement; Gas: Information Technology; Real Estate and Facilities Capital Investments; Training Capital Investments; Tools, Fleet, and Other.

213. To be clear, even though the Commission is extending the timeline for expending or increasing the budgets from three years to five years, the Commission is approving only three years of budgeted spending. The Commission is not approving further work in these areas at this time. In other words, if the particular program does not perform as expected, or is otherwise unsupported in future rate cases, the Commission may decline to continue recovery of program budgets in BGE's next rate case.

214. Given the reduced revenue requirement that the Commission has approved today, BGE may have different views on how to most effectively spend the available funds. Accordingly, the Commission directs BGE 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 by, for example, choosing to remove or further reduce select work plans in order to maximize the benefit of others. BGE will be in compliance as long as it does not exceed the reduced capital budget revenue requirement. Additionally, stakeholders will have an opportunity to file comments in response to BGE's 60-day report.

G. Request for Stakeholder-Engaged Distribution Planning and Capital Budgeting Process

OPC

215. OPC asserts that Maryland's limited seven-month rate case timeline "hampers stakeholder capacity to engage in a thorough examination of a utility's planning processes," and that given the adversarial nature of a litigated rate case, "a utility is less likely to accept a stakeholder planning recommendation."[382] To support that premise, OPC states that BGE has "rejected every single recommendation that OPC's electric and gas planning witnesses made in their testimonies."[383] For these reasons, OPC argues that greater and earlier stakeholder involvement is required.

216. In order to remedy this issue, OPC witness Alvarez testified that the Commission should authorize a process that will increase transparency into distribution planning, and "reduce the information, resource, and expertise asymmetry which have always plagued monopoly regulation."[384] Specifically, he recommended that the Commission establish a transparent, stakeholder-engaged distribution planning and capital budgeting process, either in Public Conference 44 ("PC44"), or in another Commission docket. The basic steps of this process would include: (i) Utilities and stakeholders create a vision for the grid of the future, including goals and targets for quantifiable metrics; (ii) Utilities forecast future loads and distributed generation ("DG") by circuit, including constraints and risks; (iii) Stakeholders examine the constraints and risks, as well as proposed solutions, and may propose lower-cost solutions; (iv) Stakeholders and utilities negotiate

[382] OPC Initial Brief at 27.
[383] *Id*.
[384] Alvarez / Stephens Direct at 57.

an optimized grid development plan and associated capital budget; and (v) The utility implements the agreed-upon plan. Results would be measured against the targets established in Step 1.[385]

BGE Rebuttal

217. BGE opposes OPC's recommendation for a stakeholder-engaged planning process at this time. The Company stated that OPC's proposal is similar to its recommendation in Case No. 9353, which the Commission already declined to adopt.[386] BGE asserts that in that case, the Commission found that it would be premature to establish a stakeholder process because of ongoing work being conducted in another forum.

Commission Decision

218. Throughout this proceeding, BGE has stressed the importance of transparency in an MRP and highlighted the greater transparency benefits of an MRP vis-à-vis a traditional rate case.[387] The Commission, also, has emphasized the importance of transparency and planning in an MRP. In the MRP Pilot Order, the Commission found that "[a] key element of an MRP is that it provides more transparency into a utility's planning process," and that "[a]n MRP will require significant detail into utility planning that is not available to interested parties today."[388]

219. The present case has demonstrated that there is significant room for improvement with regard to the transparency of the stakeholder-engaged planning process for future

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385 *Id*. at 58.

386 BGE Reply Brief at 33, citing *In the Matter of the Review of Annual Performance Reports on Electric Service Reliability*, Case No. 9353, Order No. 89629 (September 1, 2020).

387 *See*, e.g., BGE Initial Brief at 5 ("By basing the [MRP] on the Company's actual work plans, the [MRP] process has provided, and will continue to provide, a heightened level of transparency and accountability. Stakeholders now have a clearer picture of the Company's planned investments, which allows stakeholders to participate in upcoming reconciliations and prudency reviews in a much more informed way.").

388 MRP Pilot Order at 54.

rates in an MRP. Both Staff and OPC witnesses have complained that the process in this rate case has at times lacked transparency.[389] Even BGE has acknowledged that it could have shared information more fully initially, and the experiences from this pilot have led to important lessons learned for future MRPs.[390]

220. In order for the MRP process to function effectively, stakeholders must have sufficient information from the utility's filing to make recommendations and adjustments in their respective direct testimonies, and the process must continue to be transparent throughout the discovery and adjudicative stages of the proceeding. As the Commission stated in its MRP Pilot Order: "Providing sufficient data on planned capital spending at the filing stage of an MRP is essential to allowing transparency into the utility planning process, which the Commission identified as a key benefit of an MRP."[391] Additional ways of improving transparency for future MRPs include harmonizing inconsistent forecasting methodologies, and developing a deeper record regarding how the utility forecasts its revenue requirement. Ongoing stakeholder engagement for future MRP proceedings is imperative. Therefore, the Commission expects to see improvement regarding the transparency issues discussed herein in future MRPs. The Commission also expects to see immediate and significant improvements in BGE's transparency in *this* proceeding, including in the reconciliation process and prudency review, annual

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[389] *See*, e.g., Staff Reply Brief at 31, OPC Reply Brief at 44-46.

[390] *See*, e.g., Hr'g Tr. at 460 (Vahos) ("I think in fairness, and we heard this from Staff as well, we didn't provide enough specificity in terms of what we were doing early in this proceeding. That's definitely a lessons learned. We will definitely take that to heart in future proceedings like the [MRP].").

[391] MRP Pilot Order at 23.

informational filings, and off ramps, if any. The Commission accepts BGE's commitment to improve its transparency as an essential lesson learned.[392]

221. Regarding OPC's specific request, the Commission finds that the type of stakeholder-engaged distribution planning and capital process outlined by OPC would be valuable to future MRPs. However, the Commission will not initiate such a process at this time. In Order No. 89629, the Commission found "intriguing" OPC's request for a similar stakeholder process, finding that OPC raised important issues "such as whether, and the extent to which, marginal increases in reliability spending suffer from diminishing returns and how individual customer classes are impacted by the costs and benefits of the spending."[393] OPC raises additional vital issues now, including those related to planning and transparency in an MRP.

222. However, as the Commission noted in Order No. 89629, the State of Maryland is currently an active participant in a 16-state National Task Force, which is jointly sponsored by the National Association of Regulatory Utility Commissioners ("NARUC") and the National Association of State Energy Officials ("NASEO"), and is facilitated by the U.S. Department of Energy. This Task Force is working towards a best practices roadmap to distribution system planning, including transparency considerations for the nation that may be instructive to the Commission and other parties when the Task Force produces its work product and recommendations. Those results are expected to be available in Q1 of 2021.

[392] *See* Hr'g Tr. at 460 (Vahos).
[393] Order No. 89629 at 33.

223. Accordingly, the Commission finds, consistent with Order No. 89629, that the limited resources of Commission staff and the Parties would be best utilized, and the risk of redundancy and/or inconsistency minimized, by waiting until the Task Force issues its work product and recommendations to consider authorizing a stakeholder-engaged distribution planning and capital budgeting process. OPC is encouraged to renew its request at that time.

II. Electric Vehicle Program

224. In Order No. 88997, in Case No. 9478, the Commission approved in part the petition filed by BGE (among others) to create an Electric Vehicle ("EV") charging program. As a condition of that approval, Order No. 88997 required that BGE must provide a benefit-cost assessment ("BCA") of its EV program for cost recovery in future rate cases.[394] BGE is seeking to recover EV program costs in this rate case.

BGE

225. In this case, BGE presented its BCA through witness Mark Warner. Mr. Warner testified that there are three primary benefits to transitioning to electric vehicles: (1) operational savings in terms of reduced fuel and maintenance costs; (2) reductions in emissions, including CO_2 and NO_x, which have greenhouse gas and public health effects; and (3) reductions in the cost of electricity through changes in the load curve, improved asset utilization, and changes to transmission and capacity costs.[395]

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[394] Case No. 9478, Order No. 88997 at 44, fn. 170 (requiring BGE to "include a detailed cost-benefit assessment—through a traditional test or a combination of tests—to substantiate, empirically, all cost expenditures related to EV charging for purposes of cost recovery in any future rate case").

[395] Warner Rebuttal at 1-2.

226. Mr. Warner further testified that he developed multiple tests to assess the benefits and costs of BGE's EV program from different perspectives.[396] Those include (1) a portfolio view that reviews impact on ratepayers of the changes in electricity costs and emissions; (2) market-wide societal cost tests that assess the collective impact on all parties under both a hypothetical scenario where all charging occurs outside peak hours and one where charging times are not controlled; and (3) "merit tests" for specific utility offerings, including residential whole-house time of use, residential Level 2 off-peak charging, commercial multi-family, and public charging initiatives.[397] Mr. Warner testified his analysis found that each of these offerings showed a positive return of benefits compared to costs.[398]

OPC

227. OPC witness Courtney Lane challenged BGE witness Warner's methodology and conclusions. She testified that Mr. Warner incorrectly excluded key costs and benefits and instead focused on metrics that include costs and benefits not directly attributable to BGE's programs, which she argued conflates cost-effectiveness with ratepayer impact.[399] She objected to Mr. Warner's inclusion of BGE revenue changes as benefits.[400] She also testified that Mr. Warner's testimony does not provide for meaningful comparisons because he used different cost-effectiveness tests to assess different cases.[401] As a result of these highlighted issues, Ms. Lane concluded that Mr. Warner did not adhere to the

[396] Warner Direct at 3.
[397] *Id*. at 3-4.
[398] Summaries of witness Warner's conclusions under each of those tests appear in a chart on page 4 of his Direct.
[399] Lane Direct at 4; Lane Surrebuttal 2-4.
[400] Lane Direct at 4.
[401] Lane Surrebuttal 3.

methodologies outlined in the National Standards Practice Manual for Benefits-Cost Analysis.[402]

228. OPC witness Lane also testified that Mr. Warner failed to provide useful ratepayer impact statements, presenting instead offer-specific merit tests that do not show how rates will increase or decrease and for whom and when.[403] She also testified that in order to evaluate cost-effectiveness from a ratepayer perspective, non-monetized environmental benefits should be removed from the analysis.[404]

229. Ultimately, OPC witness Lane recommended that the Commission not accept Mr. Warner's methodology as precedential and should instead: (1) require any future BCA of a utility EV program to reflect the full benefits and costs applicable to that program and adhere to the principles of the National Standards Practice Manual, a manual on cost-effectiveness for distributed energy resources developed by the National Energy Screening Project; (2) not permit any future BCA of utility EV offerings to include the impact of changes to utility revenues; (3) require BGE to provide a justification of the costs related to BGE-owned EV chargers as part of its consolidated reconciliation and final reconciliation as proposed in its MRP filing; (4) require BGE to conduct a BCA for each program offering at the end of the five-year pilot period that corrects for the deficiencies identified in her direct testimony; and (5) require BGE to conduct a rate and bill impacts analysis for each customer rate class at the end of the five-year EV pilot period to assess the overall ratepayer impacts from its portfolio of EV offerings.[405]

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402 Lane Direct at 4.

403 Lane Surrebuttal at 3.

404 *Id*. at 12.

405 Lane Direct at 5; Lane Surrebuttal at 4.

230. In Rebuttal, BGE witness Warner testified that he found OPC witness Lane's "strict" reliance on the National Standard Practice Manual was not fully justified at this time.[406] He argued that analysis of the impacts of EVs required an approach that went beyond the limits of that manual (though he noted that a revised version was released in August 2020 and argued that its approach to EVs aligned with his own), and he pointed to a number of other approaches used in other states that were allegedly similar to his methodology.[407] He also developed a variation of his analysis that removed consideration of increased utility revenues, which according to him had a "relatively modest" impact and did not change his conclusion that EVs are strongly beneficial.[408]

231. Mr. Warner further testified that he believes he and OPC witness Lane disagreed on the objectives of the Commission's BCA requirement. He was focused on providing insight into both: (1) the net benefit for society as a whole of vehicle electrification; and (2) likely ratepayer impact for each utility offering; whereas he understood that Ms. Lane believed these two areas should be strictly separated.[409] Mr. Warner testified that he believes his market-wide analyses measured net benefit and the separate tests for each offer assessing the likely impact on ratepayers.[410] In live testimony, Mr. Warner further explained that there is not yet a standard test specifically for EV programs of this sort, so he adapted existing tests typically used in other areas.[411]

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[406] Warner Rebuttal at 11.
[407] *Id*. at 12-13.
[408] *Id*. at 17.
[409] *Id*. at 11-12.
[410] *Id*. at 16-17.
[411] Hr'g Tr. at 302-03 (Warner).

232. In her live testimony, OPC witness Lane testified that she remained concerned that Mr. Warner's analysis failed to capture all the benefits and costs of BGE's EV program.[412]

Staff

233. Staff witness Drew McAuliffe testified that BGE witness Warner's estimates of the growth rate in the number of EVs in Maryland are optimistic, especially with the impact of COVID-19 on EV sales, which has been strongly negative.[413] For example, he testified that Mr. Warner was too optimistic in estimating that 100 percent of charging can be done in non-peak hours.[414] Mr. McAuliffe testified that changing these assumptions cuts the benefit-to-cost ratio substantially and that there are other variables that could also be changed, from which he concluded that Mr. Warner's exact estimates should not be relied on.[415] Staff witness McAuliffe also questioned how BGE stated in its previous EV filing that it had a total budget of approximately $24 million, but the BCA filing in this case showed a budget of approximately $28 million.[416] Mr. McAuliffe ultimately recommended that BGE should be required to provide evidence and support for its request to recover the costs of its EV portfolio from ratepayers.[417]

234. In Rebuttal, BGE witness Warner updated his projections with more recent data that included time periods affected by the recent COVID-19 pandemic.[418] Mr. Warner also testified that his projections covered multiple boundary cases, including where

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[412] *Id*. at 911-912 (McAuliffe).
[413] McAuliffe Direct at 62.
[414] *Id*. at 63.
[415] *Id*.
[416] *Id*. at 64.
[417] *Id*.
[418] Warner Rebuttal at 4.

charging was managed to limit increased system peak load, but also in cases where it was not, in order to show the potential for managed charging to impact the need for infrastructure investment.[419] He further testified that Mr. McAuliffe's concern that the models were too sensitive to changed conditions was overstated because certain conditions vary with one another and serve to balance out one another, and that Mr. McAuliffe selected for his examples one of the most impactful variables in the model.[420] Mr. Warner also testified that his analysis attempted to address the entire useful life of the investments, which extended beyond the period already approved by the Commission.[421] Mr. Warner acknowledged that his analysis cannot provide absolute certainty but was only an attempt at a reasonable prospective view on net benefits.[422]

235. In his Rebuttal Testimony, Staff witness McAuliffe argued that he thought Mr. Warner should have proposed more realistic cases and not extreme boundary hypotheticals.[423] He also reiterated that while he believes that Mr. Warner did a thorough analysis, his final BCA numbers should not be relied on.[424]

236. In his live testimony, Mr. Warner testified, in response to concerns that his natural and managed charging scenarios were extreme, that selecting a midpoint between those boundary cases would have required him to speculate as to many variables and that he

[419] *Id*. at 5-6.
[420] *Id*. at 6-8.
[421] *Id*. at 9-10.
[422] *Id*. at 10-11.
[423] McAuliffe Rebuttal at 27.
[424] *Id*. at 28.

was concerned that such speculation would have been unreasonable and open to question.[425]

Commission Decision

237. Although the Commission finds that BGE has made a good faith effort to provide a BCA for its EV programs, Staff and OPC have raised concerns with BGE's analysis that go to the center of the usefulness of that analysis—namely, which benefits and costs (and from which perspectives) to evaluate, and which methods to use. OPC also raised concerns about the precedent that would come with any Commission decision addressing BGE's BCA, and how that might affect future BCAs filed by other utilities with EV programs. Neither Staff[426] nor OPC[427] recommend cost recovery be denied for the EV program in this case; however, these concerns demonstrate the need for clarity and consistency on this issue. The Commission therefore finds it would be premature to impose greater structure based solely on the instant record, without the benefit of receiving input from other interested parties.

238. The Commission therefore directs the PC44 Electric Vehicle Work Group ("EV Work Group") to develop and propose for Commission consideration a consensus benefit-cost approach and methodology by December 1, 2021. That proposal should address, though it need not adopt, the concerns raised in this case as well as any others that develop during the Work Group process. The Commission specifically requests that the EV Work Group examine the National Standard Practice Manual and the existing

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[425] Hr'g Tr. at 261-265 (Warner).

[426] Staff Reply Brief at 22.

[427] OPC recommends that BGE be required to file another BCA at the conclusion of its five-year EV pilot program. OPC Initial Br. at 71-72.

BCA framework used to review the EmPOWER Maryland programs for best practices in developing an EV BCA methodology. The directive contained in footnote 170 of Order No. 88997 to include within any future rate case a BCA on EV programs is temporarily stayed pending future Commission order.

239. At this time, the Commission makes no prudency findings as to the EV costs requested in this rate case, but those costs may be moved into rates as proposed. Prudency questions will be addressed as part of the prudency review at the conclusion of the three-year MRP rate-effective period.

III. Cost of Capital

240. 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 features competing cost of debt projections based on the movement of bond yields throughout the three-year effective period of rates. 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 BGE is a subsidiary of Exelon, and thus its stock is not publicly traded, the Commission must still examine BGE's level of risk and its capital structure to determine its cost of capital.

241. In this case, the Commission heard testimony on cost of capital from witnesses for BGE, Commission Staff, OPC, Walmart, and the Department of Defense. Except for Walmart,[428] the parties recommended the following ROEs:

	BGE	Staff	OPC	DOD
Gas	10.1[429]	9.6	8.75	9.25
Electric	10.1	9.4	8.75	9.25

242. In support of those recommendations, the Parties presented competing financial analyses, which involved comparing BGE to other utilities for the purposes of developing a proxy group. The Parties also 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 BGE's proposed capital structure, certain Parties raised concerns. BGE also proposed a ROE "performance adder," which was opposed by all other Parties.

A. Proxy Groups

243. As part of their analyses, the Parties attempted to create proxy groups of companies with comparable risk to BGE's gas and electric businesses.

<u>BGE</u>

244. BGE witness Adrien McKenzie testified that he created separate electric and gas proxy groups of 32 electric utilities and nine gas utilities, respectively.[430] He further

[428] Walmart offered testimony responding to BGE's proposed ROE but did not make a specific ROE recommendation of its own.
[429] 9.9 percent base ROE plus a proposed 0.2 percent performance adder results in a 10.1 percent ROE for both gas and electric utilities.
[430] McKenzie Direct at 3, 6-7.

testified that the majority of proxy utilities operate in states that have approved formula rates or MRPs.[431] Mr. McKenzie also testified that he created another proxy group of non-utilities, though he did not rely on any analysis of that group in reaching his ultimate recommendations.[432]

Staff

245. Staff witness McAuliffe testified that he created an electric proxy group consisting only of companies that were identified by Value Line having a financial strength rating of B++ or greater, in order to exclude companies experiencing financial difficulty.[433] Mr. McAuliffe also excluded two companies Mr. McKenzie included in his proxy group, BGE's parent Exelon, and FirstEnergy Corp, whose stock price may have been affected by a recent federal investigation.[434] Mr. McAuliffe used the same methods for selecting his gas proxy group and reached the same proxy group as Mr. McKenzie except for NiSource Inc., which Mr. McAuliffe excluded because it had only a B+ financial strength rating from Value Line.[435]

OPC

246. OPC witness Dr. J. Randall Woolridge testified that he considered three proxy groups, one each for electric and gas utilities and also a modified version of Mr. McKenzie's proxy group.[436] Dr. Woolridge testified that his review of S&P and

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431 *Id*. at 11.

432 McKenzie Direct at 51. Because witness McKenzie testified that he did not rely on non-utility proxies in making his recommendation, this Order will not make further mention of those proxies or any analysis performed on them.

433 *Id*. at 19.

434 *Id*. at 19.

435 *Id*. at 20.

436 *Id*. at 23.

Moody's data showed that BGE's investment risk was less than the investment risk of the groups.[437]

247. In rebuttal, Mr. McKenzie testified that Dr. Woolridge overstated the degree to which BGE's credit rating was superior to that of the gas proxy group and criticized Dr. Woolridge's reliance on the credit ratings of the parent companies rather than the subsidiary gas companies.[438] In surrebuttal, Dr. Woolridge testified that S&P and Moody's credit ratings suggest that BGE's investment risk is below the average of the proxy group and that the parent companies' credit rating is appropriate because the parent companies are the proxies whose common stock is used for financial models such as the Discounted Cash Flow and Capital Asset Pricing Model.[439]

DOD

248. DOD witness Christopher Walters performed his analyses on the same two proxy groups developed by BGE witness McKenzie with two exceptions.[440] Mr. Walters excluded a foreign company from the electric group and a company from the gas group that did not have credit ratings from Moody's or S&P.

B. The Economic Climate and COVID-19

249. Throughout their prefiled and live testimonies, the witnesses each presented competing viewpoints on the impact that the COVID-19 pandemic will have on the economic climate that BGE will face throughout the three-year term of this MYP, a major common factor in their projections under the models discussed below.

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[437] Woolridge Direct at 25.

[438] McKenzie Rebuttal at 53-54.

[439] Woolridge Surrebuttal at 13.

[440] Walters Direct at 21-22.

250. BGE witness McKenzie testified that, as a result of COVID-19, he updated his original analyses based on more recent data, although this did not change his ultimate recommendation.[441] He testified that the Dow Jones Utility Average has shown considerable volatility since the COVID-19 pandemic began, which indicates that investors are perceiving elevated risk.[442]

251. In live testimony at the evidentiary hearing, Mr. McKenzie further testified that the Federal Reserve has taken unprecedented measures to support financial markets since the COVID-19 pandemic, including purchases of treasury bonds and corporate bonds, which has the impact of pushing down bond yields.[443] He testified that equity prices for common equity shares in public utilities have fallen during this time, which has increased the sense of risk.[444] He also testified that the Federal Reserve has published projections showing an increase in the federal funds rate from "essentially zero" to two and a half percent over the next five to six years.[445] He further testified that the Federal Reserve Bank of Philadelphia published a survey of professional forecasters suggesting that 10-year treasury bond yields will triple between now and 2023.[446]

252. Staff witness McAuliffe testified that he expected interest rates to continue to fall, based on statements from the Federal Reserve regarding holding the Federal Funds Rate at zero until at least 2022.[447] He also testified that, despite volatility in the market, many

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[441] McKenzie Rebuttal at 96-100.
[442] *Id*. at 14.
[443] Hr'g Tr. at 346-47 (McKenzie).
[444] *Id*. at 347-48 (McKenzie).
[445] *Id*. at 382-383 (McKenzie).
[446] *Id*. at 385 (McKenzie).
[447] *Id*. Direct at 12, 42.

utilities have seen flat demand on average, and that the Commission has taken action to limit any increased risks otherwise imposed on utilities as a result of COVID-19.[448]

253. DOD witness Walters also testified that the consensus of independent economists is that the federal funds rate and long-term interest rates will both be flat to declining slightly over the near term.[449]

254. In his Surrebuttal Testimony, OPC witness Woolridge testified that BGE has failed to recognize the relationship between the level of interest rates and the return that equity investors require and the evidence that Federal Reserve officials intend to keep interest rates low through 2023 to help the economy fully recover.[450] He also pointed to recent studies comparing predictions of future interest rates and actual (historic) interest rates, which he testified demonstrated a tendency for economic forecasters to predict rising interest rates while interest rates themselves have not risen.[451]

C. The Discounted Cash Flow Method

255. Witnesses for BGE, Staff, OPC, and DOD presented testimony on the Discounted Cash Flow ("DCF") Method of valuation.

BGE

256. BGE witness McKenzie testified that the DCF model assumes that 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

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448 *Id*. Direct at 17-18.

449 Walters Direct at 14-15.

450 Woolridge Surrebuttal at 3-5.

451 *Id*. at 8-9.

the investor's required rate of return.[452] He further testified that this 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.[453]

257. Mr. McKenzie testified that he calculated the dividend yields for the proxy groups from published dividend data produced by Value Line.[454] He also testified that he relied on projected growth rates for the proxy groups published by Value Line, IBES, and Zacks,[455] and that he calculated projected "sustainable growth rates" for the proxy companies.[456]

258. Mr. McKenzie testified that, consistent with Federal Energy Regulatory Commission ("FERC") practice, he removed from the resulting values any DCF estimates that were "implausibly low or high."[457] As a floor, he selected 6.5 percent.[458] He also excluded two estimates at the high end of the proxy group, though he testified that there was no objective benchmark for doing so.[459]

259. Based on these assumptions, Mr. McKenzie projected a range of ROEs with averages between 8.0 and 8.9 percent for electric and 8.9 and 10.9 percent for gas, and midpoints between 8.8 and 10 percent for electric and between 8.7 and 10.6 for gas.[460]

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[452] McKenzie Direct at 21-22.
[453] *Id*. at 22.
[454] *Id*. at 23.
[455] *Id*. at 29.
[456] *Id*. at 29-30.
[457] *Id*. at 30.
[458] *Id*. at 30-33.
[459] *Id*. at 34.
[460] McKenzie Rebuttal at 95-97 and Exhibit AMM-19.

260. Staff witness McAuliffe noted several differences between his own DCF analysis, discussed below, and that of Mr. McKenzie, but stated that he had no issue with Mr. McKenzie's methods.[461] Mr. McAuliffe attributed the difference in results between Mr. McKenzie and himself to Mr. McKenzie's preference for midpoints instead of averages.[462]

261. OPC witness Woolridge criticized Mr. McKenzie's DCF analysis in three ways: (1) he objected to Mr. McKenzie's decision to eliminate proxy companies from his results that he believed showed a return that was too low; (2) he objected to Mr. McKenzie's reliance on growth forecasts which he felt were overly optimistic based on his review of the research literature; and (3) he objected to Mr. McKenzie's combination of Value Line earnings estimates for the next three years, which he argued were upwardly biased due to recent outliers, with First Call and Zack's estimates covering a longer three-to-five year window.[463]

262. DOD witness Walters criticized Mr. McKenzie's DCF analysis for excluding low-end outliers and for relying on a data set that included companies with expected growth rates in excess of 20 percent, which Mr. Walters considered unsustainable.[464]

263. In Rebuttal, Mr. McKenzie testified that he properly excluded the extreme values from his analysis because, in his view, they do not provide meaningful guidance.[465] He

[461] McAuliffe Direct at 43.
[462] *Id*. at 43-44.
[463] Woolridge Direct at 68-73.
[464] Walters Direct at 60, 63.
[465] McKenzie Rebuttal at 19.

argued that his approach was similar to that of Mr. McAuliffe and criticized the results of witnesses who failed to make such exclusions.[466]

264. In Surrebuttal, Dr. Woolridge testified that Mr. McKenzie improperly applied the FERC low-end filter.[467] Dr. Woolridge testified that FERC's filter calls for using a filter cutoff of the six-month average utility bond rate plus 100 basis points, which in this case would produce a cutoff at 4.78 percent, but Mr. McKenzie set his filter equal to a projected Aa utility bond rate of 4.43 percent plus a 50 basis point adjustment to account for the difference between Aa and Baa bond yields, plus FERC's 100 point adjustment, plus an additional adjustment to account for the relationship between interest rates and risk premia to reach a low-end filter of 6.50 percent.[468] Dr. Woolridge also reiterated his position that the use of a filter in this case is not appropriate because individual DCF estimates contain errors which are accounted for by taking means and medians of the entire group, which he testified leads to a more meaningful measure than if some data points are excluded.[469]

Staff

265. Staff witness McAuliffe also performed a DCF analysis, which produced ROEs for electricity of 8.89 percent and for gas of 10.01 percent.[470] Mr. McAuliffe testified that he excluded any companies from this analysis that had an ROE below 6.5 percent or

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[466] *Id*. at 60, 82.
[467] Woolridge Surrebuttal at 16-17.
[468] *Id*. at 16-18.
[469] *Id*. at 18.
[470] McAuliffe Direct at 15.

above 14 percent, finding that these were unreasonable.[471] He also testified that he relied on data from Value Line and Yahoo Finance.[472]

266. In Rebuttal, BGE witness McKenzie testified that Mr. McAuliffe erred in using a six-month period to calculate average stock prices because recent stock market price data indicates that investors have revised the prices they are willing to pay.[473] Mr. McKenzie testified that 30-day average prices are more accurate under the theory that capital markets are efficient and immediately capture current investor expectations.[474]

267. In Rebuttal, OPC witness Woolridge testified that Mr. McAuliffe made several errors in his DCF analysis. Dr. Woolridge testified that witness McAuliffe erroneously relied solely on growth rates from Value Line while ignoring other sources.[475] He also testified that Mr. McAuliffe's decision to remove high and low results from his calculation ultimately resulted in his gas DCF result being based on only five observations, a number that Dr. Woolridge testified was too small to provide a trustworthy ROE and that resulted in a median ROE of 9.35 percent but a mean of 10.01 percent.[476] In Surrebuttal, Mr. McAuliffe testified that his gas analysis was based on eight proxy companies—although for his final analysis he excluded results that he judged unreasonable—which was comparable to Dr. Woolridge's analysis, which included nine gas proxy companies.[477]

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[471] *Id*. at 20.
[472] *Id*. at 23.
[473] *Id*. at 23.
[474] *Id*. at 24.
[475] Woolridge Rebuttal at 7.
[476] *Id*. at 7-8.
[477] McAuliffe Surrebuttal at 31-32.

OPC

268. Dr. Woolridge testified that the constant-growth DCF model was appropriate for public utilities but noted that the primary problem with the model was the difficulty of estimating investors' expected dividend growth rate.[478] Dr. Woolridge applied the DCF model to each proxy group using current annual dividends and 30-day and 90-day average stock prices, and he adjusted the dividend yield to account for the expected growth over the coming year.[479] Dr. Woolridge relied on growth data from Value Line, Yahoo, and Zacks.[480] At the same time, Dr. Woolridge testified that, based on his review of the academic literature, he was of the opinion that projected earnings-per-share growth rates by Wall Street analysts tended to be overly optimistic and upwardly biased.[481] He recommended that the DCF growth rate should be adjusted downward to compensate.[482] He also calculated that the DCF method should yield ROEs of 8.7 percent for his electric proxy group and 8.95 percent for his gas proxy group.[483]

269. In Rebuttal, BGE witness McKenzie disagreed with Dr. Woolridge's reliance on historical trends in dividends per share, which he argued can differ significantly from forward-looking expectations and are already included in the published projected growth rates that he relied on.[484] He also argued that Dr. Woolridge unfairly both criticized and relied on published growth rates.[485] He also criticized Dr. Woolridge for including some

[478] Woolridge Direct at 35.
[479] *Id*. at 36-37.
[480] *Id*. at 38.
[481] *Id*. at 40-42.
[482] *Id*. at 43.
[483] *Id*. at 47.
[484] McKenzie Rebuttal at 55-56.
[485] *Id*. at 56-57.

negative growth rates in his analysis, which he argued were not meaningful.[486] He also argued that Dr. Woolridge introduced downward bias to his growth rates as a result of errors and omissions, and that his approach could generate "any DCF growth rate that he wanted" and should be considered suspect.[487] He also argued that Dr. Woolridge's claim, that long-term earnings-per-share growth is linked to GDP growth, is irrelevant because the purposes of this case do not require long-term projections and because this is not how investors structure their own expectations.[488]

270. In Surrebuttal, Dr. Woolridge testified that Mr. McKenzie failed to present valid authority supporting his criticisms of Dr. Woolridge's arguments about forecasts of dividends per share, the link between earnings and GDP growth rates, and the reliance by investors on long-term GDP growth.[489]

DOD

271. DOD witness Walters analyzed BGE's cost of equity using three different DCF models: (1) a constant growth DCF model using analysts growth rate projections; (2) a constant growth DCF model using "sustainable growth rate estimates," and (3) a multi-stage DCF model.[490] For his DCF models, Mr. Walters relied on 13-week stock prices; published quarterly dividends reported by Value Line, adjusted for future growth; and growth estimates from Zacks, Moody's, and Yahoo.[491] For his sustainable growth rate DCF model, he relied on each company's current market-to-book ratio and on Value

[486] *Id*. at 57-58.
[487] *Id*. at 60-61.
[488] *Id*. at 67-71.
[489] Woolridge Surrebuttal at 18-27.
[490] Walters Direct at 19.
[491] *Id*. at 25-26.

Line's three-to-five-year projections.[492] He described his multi-stage DCF model as having three stages: (1) a five-year growth period at analyst-projected rates; (2) a five-year transition period with growth rates adjusted to reflect the difference between analyst projections and his estimate of a sustainable growth rate; and (3) a perpetual long-term growth period at the "maximum sustainable long-term growth rate."[493] Mr. Walters relied on long-term GDP growth projections to estimate a maximum sustainable growth rate.[494] He concluded that the DCF model returns a fair ROE of 9.0 percent.[495]

272. In Rebuttal, BGE witness McKenzie testified that Mr. Walters erred in choosing not to remove "low-end" values from his constant growth DCF results, values Mr. McKenzie termed "illogical."[496] Mr. Walters testified in Surrebuttal that his use of median results mitigated the impact of outliers, whether high or low, and reiterated his position that removing low-end outliers was arbitrary and unsupported by evidence.[497]

273. Mr. McKenzie also criticized Mr. Walters' decision to use an average of multiple published growth rates when calculating a DCF estimate for each company.[498] Mr. Walters responded in Surrebuttal that his decision to average multiple growth rates mitigates the potential of a single analyst's estimate biasing the underlying growth estimate.[499]

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[492] *Id*. at 29.
[493] *Id*. at 32.
[494] *Id*. at 28, 36-38.
[495] *Id*. at 39.
[496] McKenzie Rebuttal at 82.
[497] Walters Surrebuttal at 7-9.
[498] McKenzie Rebuttal at 82-83.
[499] Walters Surrebuttal at 10.

274. Mr. McKenzie also testified that Mr. Walters erred in not including Value Line EPS growth estimates in his analysis.[500] Mr. Walters testified in Surrebuttal that this claim was unsupported and that Value Line estimates are produced by a single analyst who could make modeling and input errors, which Mr. Walters sought to avoid by using published consensus estimates.[501]

275. Mr. McKenzie also testified that there was no merit to Mr. Walters' argument that company growth will converge to a single, theoretical sustainable growth rate.[502] Mr. Walters testified in Surrebuttal that this rule was supported by multiple authorities and that if a company grew faster than the economy in perpetuity, that company would become larger than the economy.[503]

276. Mr. McKenzie also testified that Mr. Walters relied on certain functionality within Microsoft Excel that made assumptions about cash flow inconsistent with the way investors receive dividend payments.[504] Mr. Walters testified in Surrebuttal that Mr. McKenzie did the same thing in his own DCF models and that the difference only increased DCF results by approximately five basis points, which would have virtually no impact on his recommendations.[505]

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[500] McKenzie Rebuttal at 83.
[501] Walters Surrebuttal at 10.
[502] McKenzie Rebuttal at 83.
[503] Walters Surrebuttal at 11-12.
[504] McKenzie Rebuttal at 83-84.
[505] Walters Surrebuttal at 13-14.

D. The Capital Asset Pricing Model

BGE

277. BGE witness McKenzie testified that the Capital Asset Pricing Model ("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.[506] Mr. McKenzie testified that the CAPM was 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.[507] 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 expected return on the market portfolio and the risk-free rate.[508] Mr. McKenzie also testified that CAPM overstates returns to companies with larger market capitalizations (and understates returns for smaller companies) after controlling for risk differences reflected in beta, a phenomena referred to as a "size premium."[509]

278. In his analyses, Mr. McKenzie relied on Value Line's published betas for each proxy utility.[510] He testified that, in his opinion, those measures indicate that investors would consider the overall investment risks for the firms in the proxy groups are comparable to BGE.[511] He testified that he calculated an expected market rate of return by conducting a DCF analysis on the dividend-paying firms in the S&P 500, for which

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[506] McKenzie Direct at 35.
[507] *Id*. at 36.
[508] *Id*. at 35-36.
[509] *Id*. at 37-38.
[510] *Id*. at 7-9.
[511] *Id*. at 10.

analysis he relied on published data from Value Line, IBES, and Zacks.[512] Combining the results with the 2.3 percent average return on 30-year Treasury bonds for the six months ending December 2019, he calculated a market equity risk premium of 9.8 percent.[513] After adjusting for the size premium, Mr. McKenzie concluded that a CAPM approach implies an average ROE for the electric group of 10.4 percent and for the gas group of 11.0 percent (rising from 8.2 percent and 9.8 percent, respectively, based on updated projections incorporating the effect of COVID-19).[514] Mr. McKenzie testified that he also ran the same calculation using forecasted bond yields, which were projected to increase, and that this resulted in a 10.5 percent ROE for the electric group and 11.1 percent for the gas group (also rising from 8.5 percent and 10.1 percent, respectively, based on updated projections).[515]

279. Mr. McKenzie also presented testimony on a modified version of the CAPM, called the Empirical CAPM ("ECAPM"). He testified that the ECAPM arose out of research showing that low-beta securities earn returns somewhat higher than the CAPM would predict, and vice versa, and the ECAPM therefore resembles the CAPM except that it reduces the impact of beta.[516] He further testified that utility stocks tend to have betas less than 1.0, meaning that CAPM tends to understate the cost of equity.[517] He also

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512 *Id*. at 36-37.

513 *Id*. at 37; McKenzie Rebuttal at 97.

514 McKenzie Direct at 39; McKenzie Rebuttal at 97-98 and Exhibit AMM-19.

515 *Id*.

516 McKenzie Direct at 39-40.

517 *Id*. at 40.

calculated that the average ECAPM at his projected bond yields was 10.9 percent for the electric proxy group and 11.5 for the gas proxy group.[518]

280. Staff witness McAuliffe objected to BGE witness McKenzie's use of a size adjustment (*i.e.*, size premium) for certain companies in his CAPM and ECAPM analyses, arguing that the Commission has previously rejected the use of upward size adjustments to ROE and that size adjustments are intended to compensate for the risk of competing with larger companies, a risk that is not present with public monopolies like BGE.[519] Mr. McAuliffe stated that the removal of the size adjustment reduces Mr. McKenzie's CAPM and ECAPM results by up to 130 basis points.[520]

281. Mr. McAuliffe also testified that the Commission should give Mr. McKenzie's ECAPM analysis little weight, for which he cited prior Commission and FERC precedent rejecting the use of ECAPM.[521]

282. OPC witness Woolridge criticized Mr. McKenzie's CAPM analysis on three grounds: (1) He objected to Mr. McKenzie's reliance on risk-free interest rates that he testified are much higher than current yields; (2) he disagreed with Mr. McKenzie's estimate of the market risk premium, which he testified is inconsistent with historic and projected economic and earnings growth; and (3) he disagreed with Mr. McKenzie's decision to include a company size adjustment, which he testified is unsupported by research.[522]

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[518] McKenzie Rebuttal at 98 and Exhibit AMM-19.
[519] McAuliffe Direct at 45-46.
[520] *Id*. at 47.
[521] *Id*. at 48.
[522] Woolridge Direct at 77-79, 82-96.

283. Dr. Woolridge criticized Mr. McKenzie's decision to include an ECAPM analysis, which he testified lacked theoretical or empirical validation.[523] Mr. Woolridge also testified that Mr. McKenzie inappropriately used adjusted betas in his ECAPM analysis, because adjusted betas already address empirical issues with the CAPM by increasing the expected returns for low beta stocks and vice versa.[524] He reiterated these concerns in his Surrebuttal, testifying that both Staff and the Commission have viewed the ECAPM unfavorably.[525]

284. DOD witness Walters criticized Mr. McKenzie's CAPM analysis for its growth rate, which he testified was unreasonable for being twice the expected growth of the overall US economy.[526] He also criticized its projected interest rate, which witness Walters also testified was too high.[527] He also criticized Mr. McKenzie's decision to include a size adjustment, which witness Walters testified was unreasonable and based on companies with significantly more systemic risks that are not reflective of the utility industry or BGE.[528] DOD witness Walters also criticized BGE witness McKenzie's ECAPM analysis, which he testified erroneously used adjusted betas, which double counts the value of the adjustment intended by the ECAPM, inflating return estimates.[529]

285. In Rebuttal, Mr. McKenzie argued that reliance on historical rates of return over current projections fails to account for investors' current expectations of return and that

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[523] *Id*. at 76.
[524] *Id*. at 76.
[525] Woolridge Surrebuttal at 14-15.
[526] Walters Direct at 62, 65.
[527] *Id*.
[528] *Id*.
[529] *Id*. at 68.

historical CAPM analyses (such as those presented by Staff, OPC, and DOD and discussed below) should be rejected outright.[530] In Surrebuttal, Staff witness McAuliffe testified that Mr. McKenzie himself relied on historical data in his CAPM analysis and that historic data indicated that the recent volatility, during which betas were elevated, came from a period when the market was having difficulty properly valuing investments, which was reflected in the high volatility in the market.[531] DOD witness Walters testified in Surrebuttal that reliance on historical data in estimating risk premia was an accepted practice.[532]

286. BGE witness McKenzie also disagreed with other witnesses' decisions not to use a size adjustment in their CAPM analysis to account for higher returns by smaller companies.[533] He testified that CAPM overstates returns to companies with larger market capitalizations (and understates returns for smaller companies) after controlling for risk differences reflected in beta, a phenomenon referred to as a "size premium."[534] He further testified that the source relied on by Mr. McAuliffe was already adjusted to account for the size premium effect.[535] In his live testimony, Mr. McKenzie testified that beta does not account for risk which is related to size and that a size adjustment is therefore necessary.[536]

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[530] McKenzie Rebuttal at 62-66, 86.
[531] McAuliffe Surrebuttal at 12-13, 15-16.
[532] Walters Surrebuttal at 18-19.
[533] McKenzie Rebuttal at 29, 72-73, 86.
[534] *Id*. at 30.
[535] *Id*. at 31.
[536] Hr'g Tr. at 375 (McKenzie).

Staff

287. Mr. McAuliffe also performed a CAPM analysis[537] based on three sets of betas: the current betas, the betas prior to the market downtown, and an average beta for each of the last three quarters.[538] He also testified that the market volatility caused by the COVID-19 pandemic may make estimates using recent betas inaccurate.[539] He testified that during BGE's last rate case, the average beta of the Staff electric proxy group was 0.60, a number that rose to 0.86 using the financial quarter that preceded Mr. McAuliffe's direct testimony.[540] As part of his analysis, Mr. McAuliffe again excluded any ROE results outside the 6.5 to 14 percent band.[541] He then averaged the remaining results, which produced average ROEs for electricity of 9.28 percent and for gas of 9.24 percent.[542]

288. In Rebuttal, BGE witness McKenzie argued that Mr. McAuliffe erred in excluding from his CAPM calculations companies that he also excluded from his DFC calculations.[543] Mr. McKenzie testified that there was no rationale for doing so, that the two methodologies are independent, and that the decision had a substantial downward effect on Mr. McAuliffe's estimated gas ROE.[544] In Surrebuttal, Mr. McAuliffe testified that the exclusion was motivated by a desire for a consistent result that relied on the same

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[537] McAuliffe Direct at 15.

[538] *Id*. at 26.

[539] *Id*. at 14.

[540] *Id*.

[541] *Id*. at 24.

[542] *Id*. at 26.

[543] *Id*. at 26.

[544] *Id*. at 25-26.

group of proxy companies but that, regardless, the change did not affect his ultimate recommendation.[545]

289. Mr. McKenzie also testified that he disagreed with Mr. McAuliffe's concern that recent betas are unreliable as a result of coronavirus-induced volatility.[546] Mr. McKenzie testified that the betas were calculated over a five-year period and were not over-weighted for recent events.[547] He also testified that recent increases in beta values reflect actual valuation decisions in the market and would fairly be considered by investors.[548]

290. In Rebuttal, OPC witness Woolridge testified that Mr. McAuliffe erred in constructing his equity risk premium by relying on only one method: subtracting the 30-year Treasury bond rate from the historical arithmetic mean annual stock market return over the 1926-2019 time period.[549] Dr. Woolridge testified that historical returns overstate the true equity risk premium.[550] In Surrebuttal, Mr. McAuliffe testified that he had used this method in every case where he provided ROE testimony and believed it to be a fair estimate that is not overly influenced by any one period of time, and avoids speculation about how long the current market conditions will persist.[551]

<u>*OPC*</u>

291. Dr. Woolridge performed a CAPM analysis, for which he selected a risk-free interest rate of 2.5 percent, based on historical 30-year Treasury yields.[552] He also chose

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[545] McAuliffe Surrebuttal at 11.
[546] McKenzie Rebuttal at 27.
[547] *Id*. at 28.
[548] *Id*. at 28-29.
[549] Woolridge Rebuttal at 8.
[550] *Id*. at 9-12.
[551] McAuliffe Surrebuttal at 12-13.
[552] Woolridge Direct at 49-50.

to use betas published by Value Line, though he raised a concern that they might be inflating expected return.[553] Dr. Woolridge testified that he reviewed market risk premium studies dated subsequent to January 2, 2010, which he found suggested a range of appropriate market risk premia between 4 and 6 percent, from which he selected 6.0 percent, which he described as a "conservative high estimate."[554] Ultimately, he calculated CAPM ROEs of 7.60 percent for his electric proxy group and 7.3 percent for his gas proxy group.[555]

292. In Rebuttal, Mr. McKenzie testified that Dr. Woolridge unreasonably relied on risk premium studies and surveys with methodological errors.[556]

DOD

293. DOD witness Walters performed a CAPM analysis, for which he relied on Blue Chip Financial Forecast's projected 30-year Treasury bond yields, average Value Line betas since 2014, and three calculated market risk premium estimates, one relying on a risk premium methodology and two relying on the DCF methodology.[557] Mr. Walters ultimately concluded that a fair ROE based on CAPM would be 9.5 percent.[558]

294. In Rebuttal, Mr. McKenzie testified that Mr. Walters relied erroneously on a two-step DCF approach and on non-dividend paying firms, and on stale historical betas.[559]

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[553] *Id*. at 54.
[554] *Id*. at 58-62.
[555] *Id*. at 63.
[556] McAuliffe Rebuttal at 64-66.
[557] Walters Direct at 46-48.
[558] *Id*. at 56.
[559] McKenzie Rebuttal at 86, 88.

E. The Risk Premium Method

295. BGE, Staff, and DOD each presented an analysis of BGE's potential ROE under the risk premium method.

BGE

296. Mr. McKenzie testified that the risk premium method calculates the cost of equity by determining the additional return investors require to forgo the relative safety of bonds in favor of holding equity, and then adding this premium to the measured yield on bonds.[560] 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.[561] Mr. McKenzie relied on data published by S&P Global Market Intelligence.[562]

297. Mr. McKenzie further testified that when interest rates are high, equity risk premia narrow, and when interest rates are low, equity risk premia widen.[563] He performed a regression analysis on the historical data and concluded that the equity risk premium increases by approximately 43 basis points for each decrease in interest rates for electric utilities, and 47 basis points for gas.[564]

298. From this, Mr. McKenzie calculated that the current low interest rate environment would require a 5.89 percent risk premium (up from 5.78 percent in December 2019) for electric utilities, which he added to the current average yield on triple-B utility bonds to

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[560] McKenzie Direct at 43-44.
[561] *Id*. at 44.
[562] *Id*. at 45-46.
[563] *Id*. at 46.
[564] *Id*. at 47.

reach an ROE of 9.52 percent (down from 9.56 as of December 2019).[565] This same calculation for gas utilities yielded a 9.04 percent ROE (down from 9.17).[566] Witness McKenzie also calculated, based on his expected rise in future interest rates (and bond yields) for the years 2020-2023, an expected ROE for electric utilities of 10.21 percent and for gas of 9.68 percent.[567]

299. Staff witness McAuliffe recommended that the Commission give little weight to Mr. McKenzie's risk premium analysis.[568] Mr. McAuliffe argued that Mr. McKenzie's reliance on Commission-awarded ROEs as a proxy for investor expectations was misplaced because Commissions sometimes include in their awarded ROEs certain adjustments for various reasons, such as utility performance, unrelated to financial analysis and thus investor expectations.[569] Mr. McAuliffe also objected to Mr. McKenzie's use, in his electric risk premium calculation, of lower-rated utility bonds rather than "A" rated bonds (which Mr. McKenzie used in his gas analysis, and which was BGE's current bond rating).[570] Mr. McAuliffe testified that the use of lower-rated bonds inflated Mr. McKenzie's ROE estimate.[571]

300. OPC witness Woolridge criticized Mr. McKenzie's risk premium analysis on three grounds, arguing that: (1) Mr. McKenzie relied on out-of-date long-term bond yields that "do not reflect capital costs in today's market" and include a premium for

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[565] McKenzie Direct at 47-48; McKenzie Rebuttal at 98-99 and Exhibit AMM-19.
[566] McKenzie Direct at 48; McKenzie Rebuttal at 98-99 and Exhibit AMM-19.
[567] *Id*.
[568] McAuliffe Direct at 52.
[569] *Id*. at 50.
[570] *Id*. at 51-52.
[571] *Id*.

default risk (not present for equities) that together inflate the required return; (2) Mr. McKenzie's risk premium approach was merely a gauge of Commission behavior rather than investor behavior; and (3) that the evidence that utilities have been selling at market-to-book ratios in excess of 1.0 for many years indicates that authorized rates of return are greater than the return that investors require.[572]

301. DOD witness Walters criticized Mr. McKenzie's risk premium analysis, which he testified unreasonably expected a 165 basis point increase in utility bond yields and unreasonably assumed a simple inverse relationship between equity risk premiums and interest rates, contrary to research showing that the relationship is also affected by perceived bond risk.[573]

302. In Rebuttal, Mr. McKenzie responded to concerns with the use of Commission-allowed ROEs, testifying that they are the best measure of investor expectations even when they result from settlements because there is still a commission review process.[574] Mr. McKenzie also rejected Dr. Woolridge's concerns about the relationship between market valuation and book value, a relationship which he argues has not been clearly established for utilities nor relied on by any state regulator.[575] In Surrebuttal, Dr. Woolridge testified that the fact that market-to-book ratios for some companies are greater than 1.0 means that regulators have provided ROEs that are above the return that investors require.[576]

[572] Woolridge Direct at 97-99.
[573] *Id*. at 72-73.
[574] McKenzie Rebuttal at 36-37.
[575] *Id*. at 49-51.
[576] Woolridge Surrebuttal at 29.

Staff

303. Staff witness McAuliffe also performed a risk premium analysis, by adding BGE's current long-term debt rate to an equity risk premium calculated by the average of two methodologies: (1) by subtracting the arithmetic average of the historic annual yield of Moody's "A" rated public utility bonds from the arithmetic average of the historic annual returns for the S&P 500 utilities index; and (2) by relying on estimates of publicly available equity risk premia from financial and industry experts.[577] This analysis produced ROEs for electricity of 8.74 percent and for gas of 8.74 percent.[578]

304. In Rebuttal, Mr. McKenzie criticized Mr. McAuliffe's risk premium analysis for not properly capturing forward-looking expectations of investors, incorrectly combining historical data for electric utilities with studies specific to the overall stock market, and incorrectly comparing equity risk to risk-free securities dissimilar to BGE's long-term debt.[579] Mr. McKenzie also disputed Mr. McAuliffe's use of geometric means instead of arithmetic means of historic rates of return, which would allegedly cause a downward bias in results.[580]

DOD

305. DOD witness Walters performed a risk premium analysis based on two approaches. First, he calculated the difference between Commission-authorized returns on common equity and U.S. Treasury bond yields; and second, he calculated the difference between Commission-authorized returns on common equity and "A" rated

[577] McAuliffe Direct at 27.
[578] *Id*. at 28.
[579] McKenzie Rebuttal at 33-34.
[580] *Id*. at 35.

utility bond yields.[581] Mr. Walters performed his risk-premium analysis over five and 10-year horizons in order to smooth abnormal market movement[582] and he ultimately concluded that a reasonable ROE based on his risk premium analysis would be 9.2 percent.[583]

306. In Rebuttal, BGE witness McKenzie testified that Mr. Walters failed to account for the inverse relationship between interest rates and equity risk premiums in his analysis, resulting in his relying on risk premiums that were too low.[584] Mr. Walters responded in Surrebuttal that he relied on an above-average risk premium and a below-average interest rate, which is consistent with an inverse relationship.[585]

307. Mr. McKenzie also testified that Mr. Walters erroneously excluded data prior to 1986 in his risk premium analysis, which he testified introduced a subjective bias.[586] Mr. Walters testified in Surrebuttal that Mr. McKenzie was relying on sources that refer to historical market returns over historical interest rates, but that he was relying on annual authorized utility returns, "which are generally based on evidence in the evidentiary record consisting of investor expectations and decided by regulatory commissions" and that there is no evidence that this decision caused a downward bias.[587]

F. The Expected Earnings Test

308. Only BGE presented an expected earnings analysis. BGE witness McKenzie testified that the expected earnings test involved identifying a group of companies of

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[581] Walters Direct at 40.
[582] *Id*. at 40-43.
[583] *Id*. at 44-45.
[584] McKenzie Rebuttal at 84-85.
[585] Walters Surrebuttal at 14-15.
[586] McKenzie Rebuttal at 85.
[587] Walters Surrebuttal at 15-16.

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.[588] Mr. McKenzie applied this method to data from Value Line to reach an average ROE of 10.2 percent for both the electric and gas proxy groups.[589]

309. Staff witness McAuliffe recommended that the Commission give little weight to Mr. McKenzie's expected earnings analysis,[590] arguing that Mr. McKenzie's focus on book value rather than market value is erroneous and does not align with the expectations of investors who instead measure returns based on market value, which is nearly always higher than book value.[591] Mr. McAuliffe further argued that FERC also reached this same conclusion and rejected the use of the expected earnings analysis.[592]

310. OPC witness Woolridge also criticized Mr. McKenzie's expected earnings analysis, arguing that the approach does not measure the market cost of equity capital and incorrectly focuses on book equity which usually is distinct from market price and insensitive to investor requirements.[593] Dr. Woolridge testified that the ROE ratios of the proxies are not determined by competitive forces but rather by federal and state regulatory proceedings.[594] He also criticized Mr. McKenzie's use of companies that earn income from unregulated business activities as proxies.[595]

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[588] McKenzie Direct at 49.

[589] *Id*. at 50-51; McKenzie Rebuttal at 99 and Exhibit AMM-19.

[590] McAuliffe Direct at 54.

[591] *Id*. at 53-54

[592] *Id*. at 54.

[593] Woolridge Direct at 100-101.

[594] *Id*. at 101.

[595] *Id*.

311. DOD witness Walters also criticized Mr. McKenzie's expected earnings analysis, which he testified does not measure the return an investor requires in order to make an investment and are in some cases impacted by the financial performance of nonregulated operations by holding companies.[596]

312. In Rebuttal, Mr. McKenzie testified that not being market-based does not invalidate the usefulness of the expected earnings approach, which in his opinion is not subject to the same degree of subjectivity as market-based approaches and therefore serves to complement those other approaches.[597] He also testified that whether companies are regulated is irrelevant so long as investors view the risks as comparable.[598]

G. Performance Adder

313. BGE witness Vahos testified that the Commission should also include a "performance adder" of 20 basis points to BGE's ROE to account for operating efficiency and effectiveness while achieving outstanding customer satisfaction results.[599] In live testimony at the evidentiary hearing, BGE witness McKenzie testified that he understood there were examples of such adders being approved in Alaska and Florida in the 1990s.[600] Also in live testimony, Mr. Vahos testified that the Commission could alternatively choose to consider the proposal through the Performance Incentive Mechanism structure that the Commission has addressed in Public Conference 51.[601]

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[596] Walters Direct at 76.
[597] McKenzie Rebuttal at 38-41.
[598] *Id*. at 74.
[599] Vahos Rebuttal at 20. Of note, BGE originally proposed an adder of 35 basis points, which was later revised downward. Vahos Direct at 5.
[600] Hr'g Tr. at 397-98 (McKenzie).
[601] *Id*. at 523 (Vahos).

314. Staff witness McAuliffe recommended that the Commission reject BGE's proposed performance adder,[602] arguing that the Commission's past rate case decisions have set BGE ROEs above the national average without the need for an adder.[603] He also argued that the concept of a performance adder would be better addressed through the Commission's working group studying performance-based rates as part of Public Conference 51 and Case No. 9618.[604] Staff witness Clementson also raised concerns about BGE's performance adder, noting that BGE had several gas safety incidents in recent years and that its performance on different indicators has varied.[605]

315. OPC witness Woolridge criticized the performance adder, arguing that there is neither Commission precedent for the proposal nor metrics that demonstrate performance above BGE's statutory obligations.[606]

316. Walmart witness Kronauer also recommended that the Commission reject BGE's proposed performance adder, and alternatively recommended that any performance adder should only reward specific and measurable outcomes incremental to current outcomes and customer expectations, not for what is already required or already performed with current incentives in place, and should be reduced in the event BGE fails to meet the specified and measurable outcomes.[607]

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[602] McAuliffe Direct at 55-56.
[603] *Id*. at 56.
[604] *Id*. at 57.
[605] Clementson Direct at 23-24.
[606] Woolridge Direct at 16.
[607] Kronauer Direct at 17-18.

317. In Rebuttal, BGE witness Vahos testified that any recent failures by BGE to reach performance goals are not a reflection of poor performance but of ambitious goals.[608]

H. Final ROE Recommendation

BGE

318. Mr. McKenzie recommended an ROE range for both BGE's electric and gas operations of 9.2 percent to 10.6 percent, with his final recommendation being the midpoint of those numbers, 9.9 percent.[609] In live testimony, he testified that an ROE at the bottom of his range would not be "completely outlandish," though it would be unsupportive and inconsistent with important benchmarks.[610] Mr. McKenzie further testified that a 9.5 percent ROE would be "certainly within the range of reasonableness," although a continued downward trend in ROE over time could impair BGE's credit standing.[611] Also in live testimony, Mr. Vahos testified that he "could see something" like an ROE of 9.5 or 9.6 percent.[612]

319. In live testimony, Mr. McKenzie testified that he did not rely on the principle of gradualism in his recommendation and that it is customarily applied in the context of rate design, though there are instances when regulators also consider the implications of extreme movements in the ROE based on market circumstances and what that means for

[608] Vahos Rebuttal at 21.

[609] Hr'g Tr. at 356 (McKenzie). *See also* McKenzie Rebuttal at Exhibit AMM-19.

[610] Hr'g Tr. at 390 (McKenzie).

[611] *Id*. at 391-92 (McKenzie).

[612] *Id*. at 527 (Vahos).

investors or customers.[613] Mr. McKenzie also testified that the existence of the stay-out provision in this case served to increase risk.[614]

320. In its final brief, BGE pointed to recently approved ROEs by this Commission (9.6 percent for Delmarva Power & Light, 9.7 percent for Columbia Gas of Maryland, and 9.6 percent for Washington Gas Light Co.) and argued that increased equity risks justified its request for a 9.9 percent combined ROE for both gas and electric, plus any approved performance adder.[615]

321. Staff witness McAuliffe challenged Mr. McKenzie's decision to use the midpoint of his ROE range in determining his recommended ROE, arguing that the decision reflects the extreme values of the set and not its overall trend, and that the midpoint value was subjectively chosen by Mr. McKenzie based on which data points he chose to exclude from his proxy group, the result of which was to increase the value of the midpoint.[616] He reiterated this point in his surrebuttal, citing FERC precedent for the rule that midpoints are better when assessing ROEs for a group of utilities, but that medians are preferable for evaluating a single utility.[617] Mr. McAuliffe also testified that he was concerned that Mr. McKenzie's recommended ROE (9.9 percent) was much higher than the nationwide average (in the first half of 2020, 9.55 percent for electric and 9.4 percent for gas).[618]

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613 Hr'g Tr. at 404-06 (McKenzie).
614 *Id*. at 406-07 (McKenzie).
615 BGE Reply Br. at 43-44.
616 McAuliffe Direct at 33-34.
617 McAuliffe Surrebuttal at 6-8.
618 McAuliffe Direct at 38.

322. OPC witness Woolridge also criticized Mr. McKenzie's use of midpoints, testifying that FERC has expressed a preference for using medians rather than midpoints for three reasons: (1) to lessen the impact of atypical outliers in the proxy group; (2) to give consideration to more of the companies in the proxy group rather than just those at the top and bottom; and (3) because it produces a statistically better measure of central tendency.[619]

323. In Rebuttal, Mr. McKenzie testified that his use of midpoints did not skew the data compared to using medians.[620] He also testified that his use of midpoints rather than medians was to allow each ROE result to be evaluated on its own merits, and that the use of medians causes ROEs to be lower.[621]

324. Mr. McKenzie also testified that the legal standard when approving an ROE is "not predicated on any notion of costs or savings to customers."[622] In Surrebuttal, Staff witness McAuliffe testified in response that commissions routinely adjust ROEs in ways that are not based solely on financial metrics and argued that BGE's proposed performance adder would itself be such a deviation.[623] In live testimony, Mr. McKenzie testified that the ROE should reflect the cost that BGE incurs to obtain capital but that the Commission has the discretion to consider ratepayer impacts in setting a fair ROE.[624]

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[619] Woolridge Surrebuttal at 14-16.
[620] McKenzie Rebuttal at 21.
[621] *Id*. at 93.
[622] *Id*. at 94.
[623] McAuliffe Surrebuttal at 18.
[624] Hr'g Tr. at 350 (McKenzie).

Staff

325. Mr. McAuliffe synthesized his analyses by averaging the DCF and CAPM method and rounding that result to the nearest value divisible by 5, which produced an average ROE for electricity of 9.25 percent and for gas of 9.35 percent.[625] He then adjusted those results in accordance with the principle of gradualism to reach a final recommendation of 9.4 percent ROE for electricity and 9.6 percent for gas.[626] Witness McAuliffe testified that the impact of COVID-19 on the short-term market had such a large impact on betas that he did not include CAPM results in his range of reasonable ROE results, but he did rely on the CAPM result to determine his ROE recommendation.[627] In his live testimony, he explained that he chose to recommend separate gas and electric ROEs because historically the ROEs for electric and gas utilities have been different, with electric ROEs tracking lower than gas ROEs nationwide over the last 10 years for distribution-only utilities.[628]

326. Mr. McAuliffe testified that the switch to a multi-year rate case model will reduce risk for BGE and reduce regulatory lag, but he also testified that he did not adjust his recommendation to account for this.[629] In live testimony, he testified that from Staff's review of other jurisdictions, he was not aware of any other company in the proxy group that has a multi-year rate plan that allows for reconciliations, which he viewed as favorable to the company.[630]

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[625] Hr'g Tr. at 953-54 (McAuliffe); McAuliffe Direct at 16.
[626] McAuliffe Direct at 28.
[627] *Id*. at 25.
[628] Hr'g Tr. at 960-61 (McAuliffe).
[629] McAuliffe Direct at 58.
[630] Hr'g Tr. at 971 (McAuliffe).

327. OPC witness Woolridge testified that Mr. McAuliffe had unreasonably increased his recommended ROE compared to his testimony in BGE's 2019 rate case despite lower interest rates and lower authorized ROEs nationwide in 2020 compared to 2019.[631]

OPC

328. Dr. Woolridge testified that he primarily relied on the DCF model in reaching his ultimate recommendation that the Commission award BGE an ROE of 8.75 percent for both electric and gas.[632] He also testified that the use of a multi-year rate plan should reduce utility risk if it reduces regulatory lag.[633]

329. In live testimony, Dr. Woolridge testified that the true test of ROE reasonableness is whether the company can raise capital and that, regardless of commission-awarded ROEs of the underlying utilities in many jurisdictions, the holding companies that own those utilities tend to have real ROEs of 8 to 9 percent and are able to raise equity at those prices.[634] Dr. Woolridge testified that historic ROEs for electric utilities have consistently fallen over the last decade, from an average of 10.01 percent in 2012 to 9.40 percent in the first half of 2020.[635] He relied on data showing the amounts of capital that utilities have raised over the past decade and a 2015 Moody's article finding that utilities are able to attract capital even with falling ROEs in a low interest rate environment.[636]

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[631] Woolridge Rebuttal at 5-6.
[632] Woolridge Direct at 63; OPC Reply Br. at 43.
[633] Woolridge Direct at 17.
[634] Hr'g Tr. at 905-907 (Woolridge).
[635] Woolridge Direct at 18.
[636] *Id*. at 20-21.

DOD

330. Mr. Walters recommended that the Commission approve an ROE of 9.25 percent for both electric and gas operations.[637] He testified that vertically integrated utilities earn substantially more than distribution-only utilities like BGE, when measured by allowed ROEs approved by state commissions, and that his recommendations were consistent with those national averages but that BGE's recommendations significantly exceed recent averages for electric distribution and gas utilities.[638]

331. He also testified that, despite an environment of falling ROEs for utilities, utility credit ratings have improved over the last 10 years, and utilities have been able to access increasingly large amounts of capital.[639] DOD reiterated in its brief that industry ROEs have fallen in 2020 to less than 9.5 percent while still supporting strong utility credit ratings and access to capital and that the Commission should not award BGE an ROE that is higher than necessary to support BGE's financial integrity, access to capital, and fair compensation for investors.[640]

Walmart

332. Walmart witness Kronauer testified that Walmart was concerned about BGE's proposed ROE increase on ratepayers.[641] Mr. Kronauer also testified that BGE's proposal is significantly higher than electric and gas ROEs approved by the Commission since 2017,[642] that BGE's electric proposal would be in the top 25 percent of all ROEs

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[637] Walters Surrebuttal at 3-4.
[638] *Id*. at 2-4.
[639] Walters Direct at 5-8.
[640] DOD Reply Br. at 4.
[641] Kronauer Direct at 8.
[642] *Id*. at 8-11.

approved by other utility regulatory commissions since 2017, and that BGE's gas proposal would be just outside the top 25 percent.[643] In his live testimony, Mr. Kronauer testified that, although Walmart does not make specific ROE recommendations, it would be comfortable with a 9.6 percent ROE for both electric and gas.[644]

I. Cost of Debt

333. BGE witness Vahos testified that the Commission should approve a cost of debt set to 102 basis points above the 30-year U.S. Treasury forward curve.[645] Staff witness McAuliffe recalculated BGE's proposed cost of debt based on debt issued by BGE in June 2020, resulting in a cost of debt of 3.84 percent.[646] Mr. Vahos testified that he agreed that this adjustment was appropriate.[647]

334. Mr. McAuliffe also proposed reductions from BGE's proposed cost of debt to account for estimated lower interest rates for 2021 through 2023, which reduced the cost of debt to 3.78, 3.79, and 3.77 percent in 2021, 2022, and 2023 respectively.[648] Mr. Vahos testified that those adjustments are speculative and give undue influence to the COVID-19 environment over the MRP framework that will continue for three years, and in which BGE will not have an opportunity to true-up to account for any upward rate movement.[649] Mr. Vahos proposed as an alternative that the Commission consider

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643 *Id*. at 12-15.
644 Hr'g Tr. at 671-72 (Kronauer).
645 Vahos Direct at 23.
646 McAuliffe Direct at 21-22.
647 Vahos Rebuttal at 22.
648 McAuliffe Direct at 27-31.
649 Vahos Rebuttal at 22-23.

accepting Staff's recommended cost of debt so long as the Commission permits a true-up to actual cost of debt in future MRP reconciliations.[650]

335. Staff witness McAuliffe testified that he had concerns about the proposed true-up process but that he would support the Commission allowing BGE to include the actual cost of debt in future MRP reconciliations, with a corresponding recognition of the reduction of equity risk.[651] In its final brief, Staff recommended that the Commission approve a fixed cost of debt without a true-up, but also recommended that if the Commission chose to accept BGE's true-up proposal then the Commission should also recognize it as a risk reduction with a corresponding reduction in ROE.[652]

J. Capital Structure

336. BGE witness Vahos testified in support of a capital structure of 52 percent common equity and 48 percent long-term debt.[653]

337. Staff witness McAuliffe recommended that the Commission accept the capital structure proposed by BGE witness Vahos.[654] He also testified that Mr. Vahos had assumed a cost of debt that was unreasonably high as a result of reductions in borrowing costs that developed as a result of government response to the COVID-19 pandemic.[655]

338. OPC witness Woolridge accepted BGE's proposed capital structure but argued that it was financially advantageous for BGE to allow such a "heavy-capital structure."[656] He testified that the Commission should recognize the downward impact that an

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[650] *Id*. at 24; Hr'g Tr. at 528-29.
[651] McAuliffe Surrebuttal at 26.
[652] Staff Reply Br. at 16.
[653] Vahos Rebuttal Exhibit DMV-3E Rebuttal.
[654] McAuliffe Direct at 21.
[655] *Id*. at 21-22.
[656] Woolridge Direct at 5.

unusually high equity ratio will have on the financial risk of a utility and authorize a common equity cost rate lower than that of the proxy group to reflect reduced risks due to a lower debt capitalization.[657]

339. Dr. Woolridge also testified that in his opinion it was appropriate to consider the capital structure of a utility's parent holding company and that Exelon had a common equity-to-debt ratio of 46.6 percent.[658] He testified that the use of debt at the holding-company level to finance equity at the utility level, referred to as "double leverage," can increase risk for the utility.[659]

340. In Rebuttal, Mr. McKenzie disputed Dr. Woolridge's concerns about double leverage, testifying that the rate of return and capital structure should be dictated by the risk of the investment, not the manner in which it is financed, for which he relied on FERC precedent.[660]

Commission Decision

341. A public utility must charge just and reasonable rates for the regulated services that it provides.[661] 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. As testified to by all parties, long-standing Supreme

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[657] *Id.* at 31.

[658] *Id*. at 27.

[659] *Id*. at 28-29.

[660] McKenzie Rebuttal at 76-78.

[661] 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.

Court precedent, primarily *Bluefield*[662] and *Hope Natural Gas*,[663] established a standard by which the Commission is to consider certain relevant factors when determining whether to allow a change in a utility's rates so as to allow the recovery of financing costs. In a proceeding involving a change in rate, the burden of proof is on the proponent of the change. Thus, in the instant matter, BGE bears the burden to support every element of its request for a rate increase.[664]

342. The parties in this rate proceeding have used a variety of models, methodologies, and assumptions to estimate BGE's fair ROE. Given that the cost of equity cannot be observed directly, the Commission must carefully consider both traditional methods and novel approaches, when justified. Nonetheless, the Commission has previously addressed its concerns with the ECAPM and size adjustments.[665] 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.

343. The Commission finds that ROEs of 9.50 percent for BGE's electric distribution service and 9.65 percent for BGE's gas distribution service are supported by the evidence and consistent with statutory and other legal standards. These ROEs are comparable to returns that investors expect to earn on investments of similar risk as demonstrated through the use of the witnesses' proxy groups, are sufficient to assure confidence in

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[662] *Bluefield Water Works and Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923).

[663] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[664] PUA § 3-112.

[665] Case No. 9490, *Application of Potomac Edison Co.*, Order No. 89072 at 75-76.

BGE's financial integrity, and is adequate to maintain and support BGE's credit and attract needed capital.

344. The recommended ranges of reasonableness found by the Parties showed considerable variation, but these ROEs fall toward the center of the total range of recommended results. They fall just above those recommended by Staff.[666] They fall near the high end of DOD's recommended range.[667] They fall above the range of reasonableness recommended by OPC.[668] And they fall toward the middle of the bottom half of the range recommended by BGE. [669] Although these rates reflect a nominal downward adjustment from BGE's most recently approved ROEs, they also account for changing financial markets and declining interest rates. The Commission further finds that the ROEs approved in this Order are consistent with the nationwide average of awarded ROEs for electric and gas utilities in recent years, which have shown a downward trend with a pronounced reduction in 2020.[670] Lastly, the 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, based on a forecasted revenue requirement.

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[666] Mr. McAuliffe recommended an ROE for BGE's gas business of 9.6 percent and for BGE's electric business of 9.4 percent. McAuliffe Direct at 12-13.

[667] Mr. Walters found a range of reasonableness for BGE's combined gas and electric businesses of 9.0 to 9.5 percent. Walters Direct at 3.

[668] Dr. Woolridge found a recommended range of reasonableness of between 7.3 and 8.85 percent. Woolridge Direct at 5.

[669] Mr. McKenzie found a range from 9.2 to 10.6 percent. McKenzie Rebuttal Exhibit AMM-19. Mr. McKenzie also acknowledged in his live testimony that 9.5 percent was within the range of reasonableness, and Mr. Vahos testified that he could see something like .95 or 9.6 percent. Hr'g Tr. at 391-92 (McKenzie); *Id*. at 527 (Vahos).

[670] *See* McAuliffe Direct at 40-41.

345. The Commission rejects BGE's request for an additional 20 basis point adder that would increase the overall ROE based on historic performance. The Commission set forth in Order No. 89638 its initial expectations for any proposed performance incentive mechanism. BGE's current proposal does not meet the standards set forth in Order No. 89638.

346. The Commission also finds that a fixed cost of debt of 3.78 percent for the three-year effective period of the rates approved in this Order is supported by the evidence and provides BGE a reasonable opportunity of recovering its actual cost of debt during this MRP. There was minimal disagreement among the Parties on BGE's actual cost of debt, and the rate set here is in line with Staff's proposal but adjusted to provide a single rate for the whole MRP period rather than variable rates from year-to-year.

347. The Commission rejects BGE's proposal to include a cost of debt true-up as part of this pilot multi-year plan. The debt true-up was opposed by Staff, and BGE has not established that the proposal is necessary or more fair than a fixed cost of debt in allowing BGE an opportunity to recover its prudently incurred cost of debt. Although a debt true-up could retroactively bring BGE's return closer to its actual costs, it would also potentially reduce BGE's incentive to *prudently* obtain debt capital at the most favorable rates. The Commission finds that a fixed cost of debt that is not trued-up strikes the appropriate balance.

348. The Commission approves BGE's proposed capital structure. 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.[671] BGE's proposed capital structure was not challenged by other Parties and is in line with BGE's actual capital structure and with those historically approved by this Commission.

IV. Cost of Service

349. The purpose of a cost of service study ("COSS") is to determine the costs a customer class, or in some cases a jurisdiction, imposes upon a utility company. Costs may be directly assigned or allocated based upon various allocation methodologies. Once costs are assigned, then class (and jurisdictional) rates of return can be developed, which are used to design customer rates. The Commission uses the results from cost of service studies ("COSSs") as a guide in developing appropriate customer class rates.

350. BGE's Electric COSS ("ECOSS") is presented in the Direct Testimony of April M. O'Neill and the Gas COSS ("GCOSS") is presented in the Direct Testimony of Jason Manuel. Both witnesses testified that BGE used three basic steps to measure customer class responsibility for rate base and operating expenses. These include: (Step 1) functionalization; (Step 2) classification; and (Step 3) allocation.

351. Ms. O'Neill testified that as a general matter BGE functionalizes its electric delivery service assets and related expenses as transmission or distribution operations. Electric transmission costs, which are subject to the jurisdiction of FERC, are not included in the ECOSS for the purpose of distribution service ratemaking before the Commission.[672] Electric supply costs recovered through BGE's Rider 1 – Standard Offer

[671] Case No. 9484, *Application of Baltimore Gas & Electric*, Order No. 88975 at 70-71.
[672] O'Neill Direct at 5.

Service procurement are also not included in the ECOSS analysis for the purpose of distribution service ratemaking before the Commission.[673]

352. BGE functionalizes its gas delivery and related expenses as either production, storage or distribution operations.[674] All of these costs are recovered through base distribution charges.[675] Gas commodity costs, however, are recorded through BGE's Rider 2 – Gas Commodity Price and are not included in the GCOSS.[676]

353. Classification is the process of separating the electric and gas functionalized rate base and expenses into categories that relate to how costs are incurred.[677] For example, distribution-related costs are primarily classified between demand- and customer-related components, where demand-related costs are generally driven by customer class non-coincident peak ("NCP") and/or coincident peak ("CP") demand levels. Customer-related costs are driven by the number and cost of customers connecting to gas mains and/or electric transformers (*i.e.*, service drops) and the necessary requirements for the utility to serve those customers (*i.e.*, metering, meter reading, account processing, and billing systems).[678] Occasionally, distribution costs are classified as energy-related.[679]

354. The final step in the COSS is allocation, "whereby rate base and expenses in each of the classified cost categories are assigned to specific customer classes according to

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[673] *Id*. at 5.
[674] Manuel Direct at 5.
[675] *Id*. at 5.
[676] Manuel Direct at 5.
[677] O'Neill Direct at 5.
[678] *Id*.; Manuel Direct at 5.
[679] O'Neill Direct at 6; Manuel Direct at 6.

load impositions on the distribution system and/or customer connection requirements."[680] Company costs are directly assigned to the specific customer classes whenever the costs are known to be related to investments or expenses that serve only a particular customer or group of customers (*e.g*., meters). When the costs are not directly assignable to customer classes (*e.g*., gas distribution mains), they are allocated using an appropriate methodology that best represents the cost causation principles of those elements.[681]

355. For the ECOSS, Ms. O'Neill stated that consistent with the filing requirements agreed to in the Work Group Implementation Report submitted to the Commission on December 20, 2019, in Case No. 9618,[682] BGE has incorporated in the ECOSS the ratemaking adjustments to the 2019 historical test year that BGE witness Vahos proposed in Part 1 of his Direct Testimony.[683] Similarly, for the GCOSS, Mr. Manuel stated that consistent with the filing requirements agreed to in the Work Group Implementation Report submitted to the Commission on December 20, 2019, in Case No. 9618, BGE has incorporated in the GCOSS the ratemaking adjustments to the 2019 historical test year that Mr. Vahos proposed in Part 1 of his Direct Testimony.[684]

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680 *Id*.

681 *Id*.

682 Maillog No. 227958, Public Utility Law Judge Division, Implementation Report, *In the matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*, Case No. 9618 (Dec. 20, 2019) ("2019 WG MRP Report").

683 O'Neill Direct at 6.

684 Manuel Direct at 16.

A. Electric Cost of Service

1. Five-Year Average v. Single-Year Average

<u>BGE</u>

356. Ms. O'Neill presented BGE's Electric Cost of Service Study ("ECOSS") based on the 12-month period ended December 31, 2019. Ms. O'Neill stated that "consistent with the filing requirements agreed to in the Work Group Implementation Report submitted to the Commission on December 20, 2019, in Case No. 9618, the Company has incorporated in the ECOSS the ratemaking adjustments to the 2019 historical test year that Mr. Vahos proposes in Part 1 of his Direct Testimony and exhibits."[685] Ms. O'Neil asserted that the ECOSS "provides a reasonable representation of each class' contribution to BGE's revenue requirement and the results will serve as a guide for the rate design in the multi-year plan."[686] In keeping with Order No. 89482,[687] where the Commission expressed agreement with the use of a single COSS to be used for the duration of the multi-year plan period, Ms. O'Neill stated that BGE does not plan to submit any additional ECOSS in support of the multi-year plan.[688]

357. Summarizing BGE's ECOSS, Ms. O'Neill stated that "[t]he ECOSS is developed to allocate costs to individual classes and then 'match' distribution revenues from each rate class with rate base and expenses allocated to the given class."[689] She explained that the ECOSS excludes all electric transmission investment and related operations and

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685 O'Neill Direct at 6.
686 *Id*. at 7.
687 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 (Feb. 4, 2020).
688 O'Neill Direct at 7.
689 *Id*. at 8.

maintenance (O&M) expenses and excludes Rider 1 electric supply costs (*i.e.*, standard offer service (SOS) procurement).[690] Further, Ms. O'Neill described the importance of the CP and NCP demand as allocators in the ECOSS. Specifically, she indicated that "CP demand is the demand of individual customer classes that coincides (in time) with the peak demand of the whole system. NCP demand represents the actual individual peak demands of each customer class although the individual class peak demands do not necessarily coincide with the time the system peak happens."[691] Ms. O'Neill noted that "an NCP allocator does not consider when the total system peak is recorded, but instead reflects more closely the diversity in customer group load patterns."[692] The NCP allocator is based on each customer class' highest hourly kW demand.[693] Ms. O'Neill recommended using "demand allocators based upon an average of demands observed for each customer class over the last five years (2015 – 2019) for Schedules R and RL. Single-year demand allocators continue to be used for the other customer classes."[694] To determine which rate classes would use the five-year average, Ms. O'Neill testified that "residential class consumption is more sensitive to weather. In years where there is abnormal weather, using single-year NCP or CP demand to allocate costs in the ECOSS may shift costs to and from these classes year over year."[695] Further, Ms. O'Neill noted that "[a]pplying a five-year average to the residential classes that are most sensitive to

[690] O'Neill Direct at 9.
[691] *Id*.
[692] O'Neill Direct at 11.
[693] *Id*.
[694] O'Neill Direct at 12.
[695] *Id*. at 18.

weather normalizes the allocation of demand-related costs."[696] She also pointed out "the residential rate classes that are being proposed to use the five-year average approach are decoupled," which "means these rate class' revenues are based on weather-normalized sales volumes so it is reasonable that the demand and throughput should be normalized as well."[697] Ms. O'Neill asserted that the five-year average is a more accurate representation of BGE's distribution system. "By using a five-year average, the volatility of these allocators due to variations in weather would be smoothed out and there would not be large differences from one year to the next."[698] Moreover, "using a five-year average will decrease the volatility from year to year and provide a stable allocation that is more representative of the cost causation of the demand and throughput related elements for these rate classes."[699]

358. The results of BGE's ECOSS customer class rates of return and relative rates of return for the 12 months ended December 31, 2019, are summarized in Table 1 below, which also indicates BGE's proposed averaged demand and throughput allocators.

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[696] *Id*.
[697] *Id*.
[698] *Id*. at 18-19.
[699] *Id*. at 18-19.

Table 1[700]

Summary of ECOSS Relative Rates of Return Recommended for Revenue Allocation Purposes and Summary of Demand and Throughput Allocators

Electric Rate Schedule[701]	Relative Rates of Return	Demand and Throughput Allocators
Schedule R	0.67	Five-Year Average
Schedule RL	0.95	Five-Year Average
Schedule G	1.06	Single-Year
Schedule GS	1.65	Single-Year
Schedule GL	1.66	Single-Year
Schedule P	1.00	Single-Year
Schedule SL	1.46	Single-Year
Schedule PL	4.09	Single-Year
Schedule T	11.95	Single-Year
EVP	-0.88	Single-Year
Total	**1.00**	

Staff

359. Staff witness David Hoppock evaluated Ms. O'Neill's proposal for use of a combination of the five-year and single-year demand and throughput allocators and recommended that the Commission reject Ms. O'Neill's proposal. Instead, Mr. Hoppock recommended "using the average of the last four years of data—2016 to 2019—to determine demand and throughput allocators for all metered classes on a per customer

[700] Table 1 represents a combination of Company Exhibit AMO-1 and Table 2: Summary of Demand and Throughput Allocators in the Direct Testimony of April O'Neil at page 17.

[701] BGE's Electric Rate Schedules are defined as Schedule R – Residential Services (including Schedules EV and RD); Schedule RL – Residential Optional Time of Use; Schedule G – General Service (including GU); Schedule GS – General Service Small; Schedule GL – General Service Large; Schedule P – Primary Voltage Service; Schedule SL – Street Lighting; Schedule PL – Private Area Lighting; and Schedule T – Transmission Voltage Service. Schedule EVP refers to BGE's newly created Utility-Owned Electric Vehicle Public Charging class.

basis and multiplying these average values by the average number of customers in each class in the HTY."[702] Mr. Hoppock stated that using the five-year averaged values as recommended by BGE witness O'Neill reduces the "year to year variability in NCP and CP caused by all factors, not just weather."[703] He stated that as he had "noted in Case No. 9610, factors such as changes in customer counts over five years affect NCP and CP values as well."[704] Mr. Hoppock pointed out that Ms. O'Neill's analysis showed sizable volatility in Schedules R and, especially, RL NCP data, "but [her analysis] does not present similar analysis of other classes."[705] Mr. Hoppock performed an analysis[706] demonstrating that other classes showed higher variation in NCP on a per-customer basis than Schedules R and RL and averaging across all classes would reduce shifts in costs across rate classes caused by year to year variability on a consistent basis and further reduce the volatility in cost allocation. Further, Mr. Hoppock argued that "[g]iven that rates are being set using forecasts over multiple years and the rates ultimately adopted by the Commission will be in effect for three years, it is logical to use average demand and throughput allocator data to try and remove year to year variability when determining related class rates of return."[707] Mr. Hoppock stated that it is important to determine these averages on a per-customer basis to remove variability due to changes in the number of customers, which can be isolated and known.[708]

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702 Hoppock Direct at 13.
703 *Id*. at 11.
704 *Id*.
705 *Id*. at 11-12.
706 *Id*. (presenting Mr. Hoppock's analysis comparing NCP volatility per customer metered rate classes).
707 *Id*. at 13.
708 *Id*. at 13-14.

360. The results of Staff's recommendation—using a four-year average per customer demand and throughput allocators for all metered classes and the weighting for AMI allocators established in Order No. 87591 in Case No. 9406—are presented in the Table 2 below.

Table 2[709] **Staff Adjusted ECOSS** **2016-2019**		
Electric Rate Schedule	**Staff Adjusted ECOSS**	**Four Year Average**
Schedule R	0.68	Four-Year Average
Schedule RL	1.04	Four-Year Average
Schedule G	0.98	Four-Year Average
Schedule GS	1.68	Four-Year Average
Schedule GL	1.61	Four-Year Average
Schedule P	1.06	Four-Year Average
Schedule SL	1.47	Single-Year
Schedule PL	4.11	Single-Year
Schedule T	12.61	Four- Year Average
EVP	-0.88	Single-Year
Total	**1.00**	

BGE Rebuttal

361. In her Rebuttal, Ms. O'Neill stated that she was not "opposed to using a four-year average" as proposed by Mr. Hoppock. She noted that the primary purpose of using a multi-year average is to reduce variability and volatility from year to year and provide

709 *See Id*. at Exhibit DH-2.

more stable allocation.[710] From that vantage point, she agreed that using a four-year average still reduces variability and volatility from year to year.[711] However, she continued to believe that averaging, if adopted, should be for a longer period such as five years and that it should be done for only the decoupled classes. Ms. O'Neill offered a few criticisms of Mr. Hoppock's approach. First, she stated that if a four-year or five-year average were expanded to other customers classes, she would limit it to only decoupled classes. She explained that "[d]ecoupled classes have revenue that are based on weather normalized sales volume, so it would follow that demand and throughput costs should also be weather normalized."[712] For non-decoupled classes, Ms. O'Neill proposed using a single-year demand and throughput allocator; because the revenue for these classes reflect the actual changes in sales volume, the related expense should not be weather normalized. Using an average allocator tends to weather normalize activity, which Ms. O'Neill argued would not be appropriate for non-decoupled classes.[713]

Staff Surrebuttal

362. In his Surrebuttal, Mr. Hoppock pointed out that "[a]lthough it is true that setting demand and throughput allocation factors based on five years of data instead of four reduces the influence of each year of data, using longer averaging periods presents problems because there are changes in use patterns over time caused by changes in the economy and technology."[714] He offered a few examples of changing technology that could impact customer usage and demand patterns such as the adoption of electric

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[710] O'Neill Rebuttal at 6.
[711] *Id.*
[712] *Id.*
[713] *Id.*
[714] Hoppock Surrebuttal at 4.

vehicles and LED lighting. He argued that when "averaging over too many years, it will include data that does not reflect how customers currently use or are likely to use electricity in the future."[715] Therefore, Mr. Hoppock stated that his "four-year averaging method properly balances reducing year to year volatility in demand and throughput allocators without using historical data that is too old to represent future demands." Next, Mr. Hoppock addressed Ms. O'Neill's concerns about applying the averaging methodology to non-decoupled classes. Specifically, Mr. Hoppock stated in his Surrebuttal that he "agree[d] with Witness O'Neill that the lighting classes should not use average demand and throughput allocators."[716] Hence they only disagreed on Schedule P and Schedule T. Regarding those classes, Mr. Hoppock contended that they should be averaged because "the NCP allocation factor … is used to allocate a significant portion of plant and year-to-year variation in non-decoupled classes' NCP affects the unitized rate of return ("URORs") of all other classes."[717]

<u>*OPC*</u>

363. OPC Witness Jerome D. Mierzwa found that BGE's ECOSS "generally appears reasonable;" however, he proposed several modifications.[718] Mr. Mierzwa indicated that his modifications relate to the use of a five-year average to develop NCP and CP allocation factors only for the residential class and the allocation of common and general plant.

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[715] *Id*.
[716] *Id*. at 7.
[717] *Id*. at 7.
[718] Mierzwa Direct at 9.

364. First, Mr. Mierzwa testified that he agreed with BGE's "use of the five-year NCP and CP allocators for the Residential Class. However, the use of the five-year average NCP and CP allocators should also be extended to the other customer classes to which BGE provides electric service."[719] He reasoned that the "other customer classes also experience year-to-year volatility in the NCP and CP demands due to weather and other factors to varying degrees, and use of the five-year average would promote rate stability."[720]

365. In his Rebuttal Testimony, Mr. Mierzwa continued to advocate extending the use of five-year averages to all classes while Mr. Hoppock extended the use of four-year averages to all classes. Mr. Mierzwa argued that "[t]he use of five-year averages satisfies the need to decrease year to year volatility, and is consistent with the Commission's Order No. 87591 in BGE Case No. 9406 which indicated that the use of the five-year averages should be explored in future rate cases."[721] Mr. Mierzwa acknowledged that "the difference in NCP and CP allocation factors developed based on a five-year versus a four-year average do not differ significantly, use of a five-year average will generally provide year to year stability since the use of a five-year average reduces the weight given each year."[722] He indicated that while Staff's proposal to use a four-year average because BGE's MRP includes four years of forecasted costs and revenues, he was not convinced of the rationale and questioned what would happen if BGE's next rate case proposes a traditional rate case using a single historical test year and not a MRP. In such

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[719] *Id*.
[720] *Id*.
[721] Mierzwa Rebuttal at 3.
[722] Mierzwa Rebuttal at 3.

a case, Mr. Mierzwa questioned whether BGE would argue for the use of one-year NCP and CP allocation factors. If so, Mr. Mierzwa stated that "[d]epending on the frequency of such filings by BGE, this could lead to significant unwarranted rate volatility."[723] Therefore, Mr. Mierzwa continued to recommend that the Commission "set as general precedent future proceedings that NCP and CP allocation factors be developed based on five-year averages for all classes."[724] Finally, Mr. Mierzwa agreed that Mr. Hoppock's proposal to develop NCP and CP allocation factors on average use per customer has merit.[725]

366. The results of OPC's recommendation—using a five-year average NCP and CP demand allocators extended to other classes and the allocation of common and general plant (discussed below)—are presented in the Table 3 below.

Table 3[726] OPC Adjusted ECOSS 2015-2019	
Electric Rate Schedule	**OPC Adjusted ECOSS**
Schedule R	0.71
Schedule RL	0.97
Schedule G	0.99
Schedule GS	2.00
Schedule GL	1.56
Schedule P	0.92
Schedule SL	1.29
Schedule PL	3.72
Schedule T	11.68
EVP	-0.88
Total	**1.00**

[723] *Id*. at 4.
[724] *Id*.
[725] *Id*.
[726] Table 3 has been adapted from Table 2 in Mierzwa Direct Testimony at 1.

Commission Decision

367. The Commission uses cost of service studies *as a guide* in developing customer class rates. The Commission has historically adopted a one-year demand allocator, reasoning in previous cases that BGE had not presented sufficient evidence to show what factors are driving the changes in demand, including analyzing "trends in peak demands across classes overtime in sufficient detail"[727] to adopt the proposed five-year averaged allocator. Here, BGE again proposes the use of a five-year averaged demand and throughput allocator for the period 2015 to 2019 for residential classes and use of the one-year demand allocator for all other classes. BGE's primary reason for recommending the five-year averaged allocator is to reduce year-over-year volatility especially for decoupled revenue classes. While the Commission agrees that reducing year-over-year volatility is an important goal, the Commission finds that BGE did not provide a detailed analysis regarding factors beyond weather that drive demand or any trend analysis in peak demands across all customer classes over a five-year (or longer) period. Additionally, the Commission finds that BGE's analysis offers no data regarding the impact that use of a five-year demand and throughput allocator for residential classes might have on other allocators across classes. Staff witness Hoppock noted that in Case No. 9610 he suggested that other factors such as customer counts over five years will affect NCP and CP values as well.[728]

368. In the present case, Mr. Hoppock was the only party in this proceeding to provide an analysis comparing the volatility of NCP across multiple rate classes whereas BGE

[727] Order No. 87591, Case No. 9406 at 183.
[728] Hoppock Direct at 11.

continued to present data that shows the volatility in Schedules R and RL only. Mr. Hoppock's analysis included an examination of 10 years of historical electric NCP data for each class and average customer per year data from 2010-2019. Mr. Hoppock testified that he used this data to calculate "the average NCP per customer per year for metered classes along with the coefficient of variation, standard deviation divided by average from 2010 - 2019 and 2015 - 2019 to provide a comparable measure of variability across all metered rate classes."[729] That analysis resulted in showing that "other classes show higher variation in NCP on a per customer basis than Schedules R and RL"; therefore, Mr. Hoppock asserted that "averaging across all classes would reduce shifts in costs across rate classes caused by year to year variability on a consistent basis and further reduce volatility in cost allocation."[730] He further argued that given BGE's MRP will set rates over multiple years, it is logical to use averaged demand and throughput allocator data to mitigate year-to-year variability when determining related class rates of return which is in contrast to a traditional rate case that sets rates based on a historic test year.[731] So Mr. Hoppock proposed using the four-year average for all metered rate classes because the coefficient of variation[732] of all classes is within the range of the Schedules R and RL coefficient of variation.[733]

369. Mr. Hoppock also addressed OPC Witness Mierzwa's comments questioning the rationale of Staff's use of four-year averaging in the present BGE MRP and what would

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729 *Id*. at 12.

730 *Id*. at 13.

731 *Id*.

732 Staff Witness Hoppock explained that "[a] low coefficient of variation means that there is less fluctuation in the data relative to the average and thus an average of the data may result in a similar/comparable output to a single year in the data set."

733 Hoppock Direct at 14.

happen if the next BGE rate case was a traditional case based on a historic test year. Mr. Hoppock stated:

> I do not believe the Commission's decision in this multi-year rate plan case should be applicable to demand allocator averaging for traditional rate cases. As I explained in my direct testimony, in traditional rate cases rates are set based on a historical test year, the approved rate of return, and approved adjustments to the historical test year. Whether to use average demand allocator values in traditional rate cases should be based on the circumstances of those cases.[734]

370. The Commission finds that Staff has demonstrated with a detailed analysis of historical data across rate classes that use of the four-year average demand and throughput allocators for all metered classes on a per-customer basis is reasonable as applied to the specific circumstances of this Pilot MRP. See Table 4 below. To be clear, however, the Commission's decision on this issue should not be viewed as precedential. This is a pilot case. The Commission acknowledges that there are likely improvements to the method proposed by Staff. One such improvement could be refining the COSS revenues for non-decoupled classes as BGE witnesses O'Neill and Manuel criticized in their rebuttal testimonies. There could be other allocators or data that should be modified in conjunction with the demand allocators. Another concern that should be considered in future cases is the impact of COVID-19 upon the allocators and the appropriateness of using data influenced by COVID-19.

371. Additionally, as previously stated in Order No. 87591 in Case No. 9406, the burden remains with BGE to present evidence to show what factors are driving the changes in demand including analysis of "trends in peak demands across classes over

[734] Hoppock Surrebuttal at 5 and 6.

time in sufficient detail"[735] to adopt any future proposed averaged allocator. The Commission declines at this time—as suggested by OPC—to "set as general precedent [for] future proceedings that NCP and CP allocation factors be developed based on five-year averages for all classes." Rather, the Commission finds that whether an average demand allocator will be used in a future traditional rate case or multi-year case will be based on the circumstances and evidence presented in those cases.

Table 4
Electric Cost of Service Study
Comparison of Each Parties' ECOSS Relative Rates of Return

Electric Rate Schedule	BGE Proposal (1) (April O'Neil)	Staff Proposal (2) (David Hoppock)	OPC Proposal (3) (Jerome Mierzwa)
R	0.67	0.68	0.71
RL	0.95	1.04	0.97
G	1.06	0.98	0.99
GS	1.65	1.68	2.00
GL	1.66	1.61	1.56
P	1.00	1.06	0.92
SL	1.46	1.47	1.29
PL	4.09	4.11	3.72
T	11.95	12.61	11.68
EVP	-0.88	-0.88	-0.85

(1) BGE proposal uses a 5-year average demand and throughput allocators for electric Residential customers (Schedules R & RL). Single-year demand and throughput allocators are used for the remaining rate schedules. BGE's averages are based on 2015 -2019 data.
(2) Staff proposal recommends using the average of the last four-years of data (2016 to 2019) to determine demand throughput allocators for *all* metered classes on a *per customer basis.* (See Hoppock Direct at 13.) Schedules SL and PL are not metered and Schedule EVP only has one year of demand and throughput data and is not averaged. (See Hoppock Direct at 13 FN 50.) Staff Proposal is adapted from Table 4 in Witness Hoppock's Direct Testimony on page 18 and reflects Staff's proposed adjustments to weighing of AMI Allocator (discussed below) and the four-year averaging of demand and throughput allocators for all metered classes. (See Hoppock Direct at 18.)
(3) OPC proposal adopts BGE's use of a five-year average demand and throughput allocators for 2015-2019 for *all* classes not just residential or metered classes. OPC's proposal is adapted from Table 2 in Witness Mierzwa's Direct Testimony on page 11 and reflects OPC's proposed adjustments to allocation of common and general plan (discussed below) and the extending five-year averaging of demand and throughput allocators for all classes. (See Mierzwa Direct at 11.)

[735] Order No. 87591, Case No. 9406 at 183.

2. AMI Allocator

BGE

372. Ms. O'Neill proposed changes to customer allocators including AMI, CUST_370DIR, and CUST_370DIRO consistent with the Settlement Agreement approved in Case No. 9610.[736] Ms. O'Neill asserted that "[b]ased on an analysis of the market and operational side benefits from Case No. 9406, [she proposes] a new method that allocates 48.6% of AMI meters based on the replacement cost of AMI meters consistent with previous rate cases, 28.2% based on NCP primary voltage at 13kV, and 23.2% based on MWH sales at premises."[737]

Staff

373. Mr. Hoppock indicated that Ms. O'Neill's AMI allocator "uses the nominal benefits [BGE] witness Pino presented in Case No. 9406" where he presented a cost benefit analysis of the Smart Grid to BGE customers.[738] In that case, Staff witness Hurley analyzed the net present value ("NPV") core benefits included in the original business case for BGE's AMI system. In his testimony there, Mr. Hurley acknowledged that by only considering the core benefits he was presenting a more conservative estimate of the benefits of BGE's AMI system. Weighing between Mr. Pino's and Mr. Hurley's analyses, the Commission ultimately determined in Order No. 87591 in Case 9406 the quantified benefits of BGE's AMI System, recognizing that it was not capturing all the benefits of AMI at the time.[739] The weights adopted by the Commission in Order No.

[736] Hoppock Direct at 7.
[737] O'Neill Direct at 15.
[738] Hoppock Direct at 9.
[739] *Id*. at 9.

87591 were 26.3 percent peak demand reductions in AMI benefit, 19.8 percent energy reduction in AMI benefits, and 53.8 percent operational benefits from AMI.[740]

374. Here, Mr. Hoppock argued that "[g]iven the Commission's ruling [in Case No. 9406], which remains unchanged to date, I propose to use the weights from Order No. 87591."[741] Additionally, Mr. Hoppock recommended that the Commission require BGE to present an updated electric AMI benefit analysis with electric AMI benefits to date on a nominal and net present value basis to ensure that AMI allocators reflect update-to-date benefits weighting going forward in its next rate case.[742]

BGE Rebuttal

375. In her Rebuttal Testimony, Ms. O'Neill expressed opposition to Staff's recommendation to use the Commission's weights for the AMI Allocator from Order No. 87951. Ms. O'Neill argued that "from a cost-causation perspective, the Company-proposed weighting is appropriate and reasonable to use for the AMI allocator since it was the Company's basis for implementation of the Smart Grid project."[743] She reiterated that "the Company based its decision on whether to deploy the Smart Grid initiative on the Company identified market side and operational side benefits that are currently included in the AMI allocator used in the ECOSS."[744] She pointed out that the weights in Order No. 87591 are similar, so using BGE's weighting is reasonable and should be accepted by the Commission.[745]

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740 *Id*. at 10.
741 *Id*.
742 *Id*.
743 O'Neill Rebuttal at 2.
744 *Id*. at 3.
745 *Id*. at 2.

Staff Surrebuttal

376. In his Surrebuttal Testimony, Mr. Hoppock reiterated his position that Ms. O'Neill weighted her AMI allocator based on benefits presented by BGE in Case No. 9406, where the Commission determined in Order No. 87591 specific values for AMI benefits—in many instances at different levels than those proposed by BGE.[746] "Given that the Commission has provided specific opinions regarding the benefits presented in Case No. 9406 that differ from those presented by BGE and the fact that Witness O'Neill's weights do not account for the time value of money,"[747] Mr. Hoppock continued to argue that the Commission should adopt his proposal to maintain the AMI allocations from Case No. 9406.

377. He also pointed out that in Order No. 87591, BGE was ordered to continue filing quarterly metric reports that include BGE's reported AMI benefits. Because Ms. O'Neill relied on testimony that was filed in 2015, and BGE is required to file its next rate case in 2023, Mr. Hoppock testified that it is not unreasonable for the Commission to require BGE to present an updated electric AMI benefits analysis based on AMI benefits to date on a nominal and net present value basis in its next rate case.[748]

OPC Rebuttal

378. In his Rebuttal Testimony, OPC witness Mierzwa rejected Mr. Hoppock's recommendation for the Commission to maintain AMI allocations at the levels set in Order No. 87891 in Case No. 9406. Mr. Mierzwa argued that it is the nature of rate case proceedings for parties to present alternatives, modifications, and/or changes to

[746] Hoppock Surrebuttal at 10.
[747] *Id*. at 10-11.
[748] *Id*. at 10.

previously accepted cost allocation and rate design methods for Commission consideration.[749] Even in this proceeding, Mr. Mierzwa noted that Mr. Hoppock proposed a change in how NCP and CP allocation factors should be determined.[750] "Proposed alternatives, modifications and/or changes should be evaluated on their merits and not simply rejected because they are different than what was previously approved by the Commission."[751] Mr. Mierzwa argued that "Mr. Hoppock has presented no evidence to demonstrate that the Company's new AMI allocation proposal is unreasonable and, therefore, it simply should not be rejected because it was not previously approved by the Commission."[752]

<u>Commission Decision</u>

379. As noted by Staff witness Hoppock, the Commission "has specifically stated the numerical value of AMI benefits and set specific benefits at different levels than those proposed by BGE in Order No. 87591."[753] Mr. Hoppock also provided a comparison chart[754] showing the final nominal electric AMI benefits presented in Case No. 9406 by BGE Witness Pino, which is the basis of BGE Witness O'Neill's recommendation in the present case, Staff witness Hurley's final position in Case No. 9406, and the Commission's final position on AMI benefits in Order No. 87891. The comparison chart

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749 Mierzwa Rebuttal at 5.
750 *Id*.
751 *Id*.
752 *Id*.
753 Hoppock Surrebuttal at 9.
754 Hoppock Direct at 10.

presented by Mr. Hoppock shows that the final positions of the weighing of AMI allocation factors in Case No. 9406 were similar to the instant case.[755]

380. At this time, absent a more detailed analysis to support BGE's updated benefit weights to the AMI allocators, the Commission accepts Staff's recommendation to maintain the benefit weighing adopted by the Commission in Order No. 87591. The Commission also directs BGE to present an updated electric AMI benefits analysis with electric AMI benefits to date on a nominal and net present value basis to ensure that AMI allocators reflect update-to-date benefit weights going forward in its next rate case.[756]

3. General and Intangible Plant Allocator

Staff

381. Mr. Hoppock discussed whether BGE should follow the Commission's recent precedent regarding separation of electric general plant (FERC Accounts 389 – 399) and intangible plant (FERC Accounts 301 – 303) between transmission and distribution functions.[757] Mr. Hoppock pointed out that in Case No. 9490 for The Potomac Edison Company ("Potomac Edison"), the Commission adopted Staff's jurisdictional and class cost of service studies where Staff evaluated "each general and intangible plant FERC account (General Accounts 389 – 398 and Intangible Accounts 301 – 303) by line item and determined whether an account should be allocated based on labor, plant or a combination of plant and labor…"[758] Additionally, in Pepco's 2019 rate case, Case No. 9602, Pepco was ordered to include an itemized analysis of FERC Accounts 389 – 399

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[755] *See* Hoppock Direct at 10.
[756] Hoppock Direct at 10.
[757] *Id*. at 18.
[758] *Id*. at 18-19.

and 302 – 303 in the base rate case to determine how much cost is attributable to labor and how much is attributable to plant.[759] Similar to the Pepco case, Mr. Hoppock pointed out here that "BGE allocates general and intangible plant between electric distribution and transmission functions using a labor allocator from its FERC Form submittal."[760] Mr. Hoppock proposed that the Commission require BGE to submit an itemized analysis of FERC Accounts 389 – 399 and 302 – 303 in its next base rate case to determine how much cost in each account is incurred due to labor versus how much cost in each account is incurred due to plant." Further, Mr. Hoppock asserted that his recommendation is consistent with the Staff cost of service studies approved by the Commission in Potomac Edison Case No. 9490 and in Pepco Case No. 9602.[761]

BGE

382. In her rebuttal, Ms. O'Neil testified that she did not agree with Staff's recommendation to itemize certain plant accounts at a lower level than the FERC account level.[762] Specifically, Ms. O'Neill contended:

> The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual provides guidance around functionalization, classification and allocation at the FERC Account level, not at a lower level. The FERC Uniform System of Accounts is an industry standard to ensure that companies are using a consistent and uniform approach to reporting financial information.[763]

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[759] *Id*. at 19.
[760] *Id*. at 19.
[761] *Id*. at 20.
[762] O'Neill Rebuttal at 7.
[763] *Id*. at 7.

383. Ms. O'Neill noted that BGE, along with other utilities, consults these standards to help determine reasonable allocators to use in the ECOSS. She further explained that the primary purpose of the cost of service study is to aid in the design of rates and serves as a guide for ratemaking.[764] In her Surrebuttal Testimony, she argued that "Staff Witness Hoppock's recommendation to itemize general and common FERC plant accounts adds a level of granularity that is not necessary or appropriate."[765]

OPC

384. In his Surrebuttal Testimony, Mr. Mierzwa testified that Mr. Hoppock's proposal should not be considered a final recommendation as Mr. Hoppock admitted that his analysis was preliminary. Nonetheless, Mr. Mierzwa generally agreed with Mr. Hoppock that BGE should be required to include an itemized analysis of its general and intangible plant accounts in its next base rate case.[766] Mr. Mierzwa continued to recommend that all electric and gas common and general plant be allocated on a composite plant allocation factor.[767]

Commission Decision

385. While the Commission agrees with BGE that the NARUC Electric Utility Cost Allocation manual is the industry standard to provide guidance around functionalization, classification, and allocation at the FERC Account level, the Commission finds that requiring BGE to evaluate electric general plant and intangible plant FERC Accounts to ensure that the accounts are properly allocated between labor, plant, or a combination would be in keeping with recent ECOSS submitted by other electric companies and may

[764] *Id*. at 7.
[765] O'Neill Surrebuttal at 1.
[766] Mierzwa Rebuttal at 6.
[767] Mierzwa Surrebuttal at 8.

have the effect of making BGE's ECOSS more precise. Therefore, the Commission adopts Staff's recommendation and directs BGE to submit an itemized analysis of FERC Accounts 389 – 399 and 302 – 303 in its next base rate case to determine how much cost in each account is incurred due to labor versus how much cost in each account is incurred due to plant.

4. Common and General Plant

OPC

386. Mr. Mierzwa expressed concern with BGE's allocation of common and general plant in its ECOSS. Specifically, Mr. Mierzwa noted that in BGE's ECOSS, common and general plant are assigned to customer classes based on a composite functionalized labor allocator even though for BGE's electric operations all plant is functionalized as distribution.[768] Mr. Mierzwa asserted that a more reasonable approach would be to allocate common and general plant based on a composite, functionalized plant allocator which would reflect total plant in service other than common and general plant.[769] He indicated that use of a composite functionalized plant allocator would better recognize that common and general plant support the operations of BGE's distribution facilities.[770] Therefore, Mr. Mierzwa recommended "that common and general plant be allocated based on allocator "PTDPLT," which reflects BGE's total gross functionalized plant in service."[771] He further testified that his recommendation concerning an allocation of common and general plant is an approach set forth in the National Association of

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[768] Mierzwa Direct at 10.
[769] *Id*.
[770] *Id*.
[771] *Id*.

Regulatory Utility Commissioners Electric Utility Cost Allocation Manual (January 1992).[772]

BGE

387. In her Rebuttal, Ms. O'Neill opposed Mr. Mierzwa's proposal to use a plant allocator for common and general plant. She explained:

> General and common plant provide the infrastructure that allows the Company's employees to carry out their daily jobs. This includes assets like office buildings, telephone and communication equipment, office and shop equipment and tools. The investment in these items is primarily related to the level of the Company's workforce and the labor allocator supports the cost causation for these items.[773]

388. Ms. O'Neill argued that an allocation of common and general plant based on operating labor ratios is appropriate and an approach set forth in the NARUC Electric Utility Cost Allocation Manual.[774] She also testified that using a labor allocator in the ECOSS is consistent with how common and general plant balances are allocated for financial reporting.[775] Finally, Ms. O'Neill pointed out that the Commission has weighed in on this allocator in previous BGE rate cases including Case Nos. 9230, 9299, and 9326, and approved BGE's use of a labor allocator for both the electric and gas cost of service studies.[776] She noted "[I]n Case No. 9326, the Commission approved BGE's use of a labor allocator stating, 'Inasmuch as we have twice previously accepted BGE's G&C plant allocation method, we consider this issue resolved, unless a party presents new

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[772] *Id*.
[773] O'Neill Rebuttal at 11.
[774] *Id*. at 11-12.
[775] *Id*. at 12.
[776] *Id*.

evidence of a better argument than mere complexity as a basis for not using a labor allocator.'"[777]

Staff

389. Staff took no position on OPC's recommendation regarding common and general plant.

Commission Decision

390. OPC Witness Mierzwa concedes that he generally finds that BGE's ECOSS is reasonable,[778] and while he recommended that the Commission adopt OPC's modification of BGE's current use of a labor allocator for common and general plant, he did not demonstrate that BGE's current practice is inappropriate. BGE Witness O'Neill, on the other hand, demonstrated that its current (and proposed) approach to common and general plant aligns with the NARUC Electric Utility Cost Allocation Manual,[779] is consistent with financial reporting of common and general plant balances,[780] and is consistent with how previous BGE rate cases have determined the issue.[781] For these reasons, the Commission rejects OPC's recommended modification of the allocator for common and general plant.

5. FERC Account 923 Outside Services

Staff

391. Mr. Hoppock expressed concerns regarding BGE's allocation of FERC Account 923 Outside Services Employed. He noted that BGE allocates *all* Account 923 expenses

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[777] *Id*. at 12-13.
[778] Mierzwa Direct at 9.
[779] O'Neill Rebuttal at 11-12.
[780] *Id*.
[781] *Id*. at 12.

using a labor allocator and that $81 million in expenses is by far the largest administrative and general expense account representing 50 percent of all administrative and general expenses.[782] He argued that:

> [g]iven that Account 923 is large and includes a wide range of expenses, and some line items appear to be very similar to other accounts which have different allocation factors, I am concerned that allocating all FERC Account 923 expenses with a single allocator does not provide an allocation that fully conforms to the principal of cost causation.[783]

392. Similar to the Proposed Order of the Public Utility Law Judge in Case No. 9602, Mr. Hoppock recommended "that the Commission require BGE to itemize and allocate expenses in FERC Account 923 based on the underlying cost causative factors for each itemized expense in its next rate case…."[784]

BGE

393. In her Rebuttal Testimony, Ms. O'Neill disagrees with Staff's proposal to itemize and allocate expenses in FERC Account 923 in its next rate case. She supports her position by explaining that the current labor allocation used for FERC Account 923 is consistent with how general plant is currently allocated, which she contends is consistent with the NARUC Electric Utility Cost Allocation Manual. Additionally, she states that "BGE allocates FERC Account 923 expenses using a labor allocator, which is consistent with the two-factor allocation basis and is in alignment with the NARUC Electric Utility

[782] Hoppock Direct at 21.
[783] *Id*. at 21.
[784] *Id*. at 22.

Cost Allocation Manual, as well as consistent with prior cost of service studies proposed by the Company."[785]

OPC

394. In his Rebuttal Testimony, Mr. Mierzwa testified that he found Mr. Hoppock's recommendation regarding an itemization of FERC Account 923 to be reasonable.[786]

Commission Decision

395. Given that the FERC 923 account is BGE's largest administrative and general expense account representing 50 percent of all administrative expenses, the Commission accepts Staff's recommendation to require BGE to present an analysis, which itemizes and allocates expenses in FERC Account 923 based on the underlying cost-causative factor for each itemized expense in its next rate case. The Commission finds that this is consistent with the Proposed Order of the Public Utility Law Judge in Case No. 9602.

6. Minimum Distribution System

DOD

396. DOD witness Michael P. Gorman presented testimony on BGE's ECOSS. Mr. Gorman stated that he generally agrees with BGE's ECOSS and will accept it for allocating BGE's revenue deficiency across rate classes in this proceeding.[787] However, he expressed concern with BGE's classification of distribution costs between its customer- and demand-related components. Mr. Gorman argued that distribution costs should be classified for both component parts. He contended that "[d]istribution costs are incurred to both connect customers to the system and also ensure that the capacity of the

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[785] O'Neill Rebuttal at 14.

[786] Mierzwa Rebuttal at 7.

[787] Gorman Direct at 28.

distribution infrastructure is capable of serving the peak demand of connected customers."[788] Mr. Gorman further explained:

> [T]he Company designs its distribution system not only to have adequate capacity to meet peak demand but it also must design the distribution infrastructure for adequate length of conductors, number of poles and towers, and line transformations, in order to be able to reach and connect all customers to the distribution system despite the geographic location and/or density of the customers. This cost causation of the distribution system depends on the geographical location of customers, the density of customers within distribution circuits, and the customer class's peak demand.[789]

397. Mr. Gorman testified that determining the amount of distribution costs that should be classified as a customer component and as a demand component "is typically done using either a zero intercept system methodology or a minimum distribution system analysis. The general results of both of these analyses identify the percentage of total distribution costs which is incurred irrespective of the customer demands on the distribution circuits."[790] Where BGE did not provide a methodology for establishing how much of its distribution costs should be classified as demand, Mr. Gorman recommended that the Commission direct BGE to perform a minimum distribution system or a zero intercept system analysis for the purposes of allocating distribution costs within an ECOSS in BGE's next rate case.[791]

398. Table 4 below shows the results of Mr. Gorman's recommendation on BGE's ECOSS "assuming 100% demand allocation of distribution costs, with an alternative cost

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[788] *Id*. at 29.
[789] *Id*.
[790] *Id*. at 30.
[791] *Id*.

of service study which classifies 30% of distribution costs as customer-related, and allocates the remaining 70% on a demand basis."[792]

Table 4[793] DOD Adjusted ECOSS 2015-2019 Compare ECOSS with and without MDS		
Electric Rate Schedule	**BGE's Relative Rate of Return**	**Gorman's Relative Rate of Return**
Schedule R	0.67	0.49
Schedule RL	0.95	0.90
Schedule G	1.06	1.08
Schedule GS	1.65	2.09
Schedule GL	1.66	2.36
Schedule P	1.00	1.60
Schedule SL	1.46	1.61
Schedule PL	4.09	3.84
Schedule T	11.95	11.95
EVP	-0.88	-0.88
Total	**1.00**	**1.00**

<u>BGE</u>

399. Ms. O'Neill explained that BGE primarily classifies distribution costs as demand costs because "the fundamental reason for building a distribution system is to deliver energy to customers, not simply to connect them to the grid."[794] She further noted that ["t"]he Company designs the system based on the expected load on the system. The mission of the cost of service study is to employ cost allocation methods that reflect how

[792] *Id*. at 31.
[793] Table 4 has been adapted from Table 10 in Gorman Direct Testimony at 31.
[794] O'Neill Rebuttal at 16.

customer classes cause investment cost of the delivery system, therefore it makes sense to use demand."[795] Moreover, Ms. O'Neill testified that the Commission has previously ruled on the use of a minimum distribution system analysis in a prior BGE rate case—Case No. 9230. She recounted that the Commission's decision stated "that the primary effect of a minimum system approach appears to re-allocate costs of a minimum level of distribution plant as customer-related. Based on the record before us, we decline to accept this methodology for the electric cost of service."[796]

400. In response to whether BGE should be required to submit a minimum distribution system or zero intercept system analysis, Ms. O'Neill disagreed given that there is recent Commission precedent against the use of a minimum distribution system or zero intercept system analysis, plus the fact that even a minimum-sized distribution system is planned for certain load-carrying capability, all of which supports the use of a demand-related allocator.[797]

Staff

401. Mr. Hoppock reviewed Commission precedent regarding minimum distribution system studies in analyzing Mr. Gorman's proposal but did not take a position in testimony regarding use of it.[798] Mr. Hoppock noted that in Case No. 9490, Potomac Edison used an ECOSS with a zero intercept study from 1986; however, the Commission agreed with Staff's recommendation to weight Potomac Edison's zero intercept study ECOSS by one-third (1/3) and weigh the ECOSS without the zero intercept study by two-

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[795] *Id*.
[796] *Id*.
[797] *Id*. at 18.
[798] Staff Initial Brief at 54.

thirds (2/3).[799] Additionally, the Commission required Potomac Edison to submit an ECOSS without a zero intercept if the Company elects to submit an ECOSS with a zero intercept.[800] Similarly, in Case No. 9456 with Southern Maryland Electric Cooperative ("SMECO"), the Settlement Agreement approved by the Commission required SMECO to submit an ECOSS without a minimum system study if it chose to file an ECOSS with a minimum system study.[801] And in Case No. 9230, the Commission rejected the Maryland Energy Group's recommendation to use a minimum system of zero cost allocation methodology in the ECOSS.[802]

402. Mr. Hoppock found that the Commission either approved the utilities' request to no longer be required to submit a minimum distribution study ECOSS, along with a base ECOSS (Case No. 9424) or required utilities who desired to use the minimum distribution study to also submit an ECOSS without a zero intercept method if it elects to submit an ECOSS with a zero intercept method (Case No. 9490)[803] Overall, in keeping with precedent, Mr. Hoppock recommended that "if the Commission accepts Witness Gorman's proposal that BGE be required to submit an ECOSS with a Minimum Distribution System or a Zero Intercept System," then "the Commission should require BGE to submit an additional ECOSS without Minimum Distribution System or a Zero Intercept System as required by the filing requirements."[804]

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[799] Hoppock Rebuttal at 5.
[800] *Id*.
[801] *Id*.
[802] *Id*.
[803] *Id*. at 4-5.
[804] *Id*. at 5.

OPC

403. OPC offered no position on Mr. Gorman's proposal regarding the minimum distribution system or zero intercept system study.

Commission Decision

While the minimum distribution system or a zero intercept system is a valid form of a Cost of Service Study, the Commission continues to find, as determined in BGE Case No. 9230, that "[t]he primary effect of a minimum system approach appears to re-allocate costs of a minimum level of distribution plant as customer-related."[805] Based on the record, the Commission declines to require BGE to submit a minimum distribution system or a zero intercept system for purposes of allocating distribution costs in its next base rate case. Commission precedent with other Maryland utilities show that the Commission has either made the filing of a minimum distribution system or a zero intercept system discretionary or eliminated it altogether. In Case No. 9424, the Public Utility Law Judge granted Delmarva and OPC's request to eliminate the requirement that the Company must file a minimum distribution system study in its future base rate case filings[806]. In Potomac Edison Case No. 9490, the Commission stated that when Potomac Edison files a COSS in its next rate case, it will have discretion to include a minimum distribution system study and if it does so, it is required to also file a cost of service study without the minimum system study.[807] Finally, in Case No. 9456, it was agreed that in the event SMECO filed a COSS with a minimum distribution system study with its next

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[805] Order No. 83907, Case 9230 at 92.
[806] O'Neill Rebuttal at 16.
[807] *Id*.

base rate case application, SMECO would also file a COSS without the minimum system analysis with the application.[808]

B. Gas Cost of Service

1. Five Year Average v. Single Year Average

<u>BGE</u>

404. Similar to the ECOSS, Mr. Manuel proposes to use five-year average demand and throughput allocators for Schedules D and C, and single-year demand and throughput allocators for the remaining schedules.[809]

405. To determine which rate schedules should use the five-year average methodology for demand and throughput allocators, Mr. Manuel testified that he performed a regression analysis, which is "a common statistical analysis that is used to help determine the strength of the relationship between multiple variables."[810] In his analysis, Mr. Manuel stated that "the dependent variable was daily demand values from 2015 to 2019 and the independent variable for gas was daily heating degree day values from 2015 to 2019."[811]

406. Mr. Manuel's analysis showed that gas Schedules D and C each exhibit a strong relationship between daily heating degrees and demand values. Therefore, he elected to use the five-year average demand and throughput allocators for these two classes and the single-year demand and throughput allocator for the remaining classes.[812] "By using a five-year average, the volatility of these allocators due to variations in weather would be

[808] *Id*. at 16 and 17.
[809] Manuel Direct at 9.
[810] *Id*. at 11.
[811] *Id*.
[812] *Id*. at 12.

smoothed out and there would not be large differences from one year to the next and any change would be gradual over time."[813] Mr. Manuel acknowledged that "weather is not the sole determining factor in how the company sizes and builds its distribution system. The company does not size the system for mild weather years; instead, it is sized based on the expected demand on the system. Using a five-year average will decrease the volatility from year to year and provide a stable allocation that is more representative of the cost causation of the demand and throughput related elements for these rate classes."[814] As with the ECOSS, all rate classes proposed by BGE to use five-year average allocators are decoupled.[815]

407. Other changes proposed in the GCOSS reflect the Settlement Agreement approved by the Commission in Case No. 9610. As part of that Settlement Agreement, BGE agreed to create a separate allocator for costs related to its large customer service representatives, to amortize the new union sick day regulatory asset over 10 years, and to revise the Schedule EG demand allocator.[816] Additionally as part of the Settlement Agreement, BGE initiated discussions with Staff, OPC, MEG, C.P. Crane, and H.A. Wagner regarding ways to improve the GCOSS and specifically sought input on these new allocators.[817]

408. The results of BGE's GCOSS customer class rates of return and relative rates of return for the 12 months ended December 31, 2019, are summarized in Table 5 below which also indicates BGE's proposed averaged demand and throughput allocators.

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[813] *Id*. at 12-13.
[814] *Id*. at 13.
[815] *Id*.
[816] *Id*. at 14.
[817] *Id*.

Table 5[818] Summary of BGE's GCOSS Relative Rate of Return	
Gas Rate Schedule	**Relative Rate of Return**
D	1.02
C	0.92
ISS	1.04
IS	0.81
EG	4.62
PLG	8.09

Staff

409. Staff witness Olivia Kuykendall reviewed BGE's GCOSS proposal to adopt a combination of five-year and single-year average demand and throughput allocators. Ms. Kuykendall recommended that BGE's proposal be rejected by the Commission. Instead, she recommended "the average of the last four years of data—2016 to 2019—to determine NCP demand allocators for Schedules D, C, ISS and IS on a per customer basis and multiplying these average values by the average number of customers in each class in the HTY."[819] Ms. Kuykendall stated that she "calculated the historical demand and throughput allocators on a per customer basis for Schedules D, C, ISS and IS" and that, in her opinion, "it is important to determine these values on a per customer basis to remove variability due to changes in the number of customers, which can be isolated and is known."[820] She testified that "[f]rom 2015 to 2019, the period over which Mr. Manuel

818 Table 5 has been adapted from Table 3 in Manuel Direct Testimony at 17.
819 Kuykendall Direct at 15.
820 *Id*. at 11.

proposes to average Schedule D demand and throughput allocation factors, the average number of Schedule D customers per year increased 3.6 percent."[821]

410. Ms. Kuykendall also recommended that the CP demand and firm throughput allocators for Schedule IS be allocated on a single-year basis and its annual throughput allocator on four-year average on a per customer basis, and multiplying these average values by the average number of customers in each class in the HTY.[822] Ms. Kuykendall added that she did not "propose to average Schedule IS CP and firm throughput allocators because the downward trend on a per customer basis for these allocators and averaging would include data that would be inconsistent with this trend. Additionally, she excluded Schedule PLG because it is not a metered customer and Schedule EG because there is not sufficient data for this class isolated from Schedule IS.[823] Like Staff witness Hoppock, she recommended a four-year average for allocators because it corresponds with the four-year period on which rates are based in the MRP filing and averaging allocators reduces year to year variability in demand and throughput allocator data from all sources, including temperature, that ultimately determines each schedule's rate of return.[824]

411. The results of Ms. Kuykendall's GCOSS customer class rates of return and relative rates of return for the 12 months ended December 31, 2019, are summarized in Table 6 below, which also indicates the Staff's proposed averaged demand and throughput allocators.

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[821] *Id*.
[822] *Id*. at 15.
[823] *Id*.
[824] *Id*. at 15-16.

Table 6[825] Summary of Staff's GCOSS Relative Rate of Return	
Gas Rate Schedule	**Relative Rate of Return**
D	1.03
C	0.88
ISS	1.03
IS	0.92
EG	4.53
PLG	8.31

412. In his Rebuttal Testimony, BGE Witness Manuel agreed that using four or five-year average demand and throughput allocators are reasonable; however, he does not support using these averages for non-decoupled classes, arguing that averaging non-decoupled classes would skew the GCOSS relative rate of return ("RROR") because the non-decoupled classes' revenue could fluctuate whereas allocated costs would be normalized.[826] Mr. Manuel also agreed that using demand and throughput allocators on a per customer basis is reasonable.[827]

<u>*OPC*</u>

413. Mr. Mierzwa testified that like the ECOSS, BGE's GCOSS generally appears reasonable; however, he proposed a modification relating to the allocation of general plant similar to his recommendation vis-à-vis the ECOSS.[828] He proposed that general plant be allocated based on "PSTDPL" which reflects BGE's total functionalized gas

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[825] Table 5 has been adapted from Table 5 in Kuykendall Direct Testimony at 17.
[826] Manuel Rebuttal at 4-5.
[827] *Id*. at 4.
[828] Mierzwa Direct at 14.

plant in service.[829] For BGE's gas operations, plant in service is functionalized to production, storage, transmission and distribution.[830]

414. Regarding use of one-year versus five-year NCP demands in BGE's GCOSS, Mr. Mierzwa testified that "there would be no material difference in the GCOSS results if five-year NCP demand allocators were utilized for all customer classes, or a combination of one-year and five-year NCP demand allocators were utilized as BGE has proposed."[831] Mr. Mierzwa determined that with respect to using a one-year or five-year average of CP demands in BGE's GCOSS, again the results would have not been materially different.[832]

415. The results of Mr. Mierzwa's GCOSS customer class rates of return and relative rates of return for the 12 months ended December 31, 2019, are summarized in Table 7 below which also indicates the OPC's proposal for general plant.

416.

Table 7[833] **Summary of OPC's GCOSS** **Relative Rate of Return**	
Gas **Rate Schedule**	**Relative** **Rate of Return**
D	1.03
C	0.90
ISS	1.02
IS	0.79
EG	4.60
PLG	8.04

[829] *Id*. at 17.
[830] *Id*.
[831] *Id*. at 15.
[832] *Id*. at 16.
[833] Table 7 has been adapted from Table 4 in Mierzwa Direct Testimony at 17.

DOD

417. Mr. Gorman testified that he agreed with the allocation methods for the production, storage, transmission and general plant accounts; however, he did not agree with the allocation method used for distribution mains.[834] He stated that BGE proposed to allocate the distribution mains to the customer classes based on NCP allocator.[835] He asserted that the Peak Day method is more reflective of cost-causation and the system design.[836] He also conducted an alternative GCOSS allocating Account 376 using BGE's Peak Day (PDAY in the GCOSS) allocator which showed that "the Residential and General Service Classes (Schedules D and C) are receiving significant subsidies from the other four customer classes (Schedules IS, ISS, EG, and PLG). These four customer classes are providing relative rates of return between 6 and 45 times the system average, while the Residential and General Service classes are showing RROR far less than the system average."[837]

418. BGE witness Manuel challenged Mr. Gorman's proposal, arguing that NCP "correlates to the highest hourly demand reached by each customer class," and BGE considers this maximum peak demand level when designing and planning the system.[838] Mr. Manuel further noted that NCP allocation of distribution mains is consistent with the Commission's preferred methodology.[839]

419. Regarding BGE's allocation of distribution mains, OPC Witness Mierzwa stated "I do not believe it reasonable to allocated [sic] distribution mains costs solely based on

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[834] Gorman Direct at 39.
[835] *Id*.
[836] *Id*.
[837] *Id*. at 42.
[838] Manuel Rebuttal at 7.
[839] *Id*. at 8.

NCP or CP demands."[840] Mr. Mierzwa indicated that a portion of distribution mains costs should be allocated based on annual, or average day, demands.[841] However, he noted Commission precedent to allocate distribution mains costs based on NCP demands in BGE Case Nos. 9406 and 9484, and Columbia Gas Case No. 9609.[842]

Commission Decision

420. As discussed above in the Electric Cost of Service Study section, the Commission uses cost of service studies to help the Commission develop customer class rates. Here, BGE proposes to use a five-year average demand and throughput allocators for the revenue decoupled classes Schedule D and C and single-year demand and throughput allocators for the non-revenue decoupled classes Schedules IS, ISS, EG and PLG. Neither OPC nor DOD oppose BGE's proposal with OPC witness Mierzwa claiming that it may not be appropriate to use the averaging approach for interruptible classes, i.e., Schedules IS, ISS and EG.[843]

421. BGE's proposal to use a five-year average for NCP and CP allocators for revenue decoupled residential classes is primarily because these rate classes' revenues are based on weather-normalized sales volume. Staff witness Kuykendall agrees that BGE's GCOSS was developed correctly but recommends a mix of four-year average and single-year demand throughput allocators. BGE finds use of either a four- or five-year average demand and throughput allocators for decoupled classes is reasonable since both serve as

840 Mierzwa Direct at 13.
841 *Id*. at 14.
842 *Id*.
843 BGE Initial Brief at 67.

a smoothing mechanism to remove volatility but recommends against using average allocators for non-decoupled classes.[844]

422. The Commission has historically allowed utilities to allocate distribution mains using NCP Demand allocators. As observed by BGE witness Manuel, "NCP allocation of distribution mains has been the long-standing preferred methodology of the Commission."[845] Indeed, the Commission has accepted the NCP allocation methodology for BGE's gas mains dating back to 1988.[846] Then in Case No. 9036, the Commission affirmed this method of allocation as follows, in pertinent part:

> [T]he gas distribution system is designed based on the NCPs of customer classes. Consequently, allocating costs on the NCP basis is consistent with customer class cost causation. * * * Finally, the NCP methodology provides a reasonable compromise between use of a coincident peak or a total throughput allocation method. For these reasons, the Commission adopts BGE's use of the NCP methodology for allocation of distribution mains.[847]

423. DOD witness Gorman noted that "NARUC recognizes that distribution mains should be allocated to customer classes based on: (1) design peak day demands for the demand component; and (2) the number of customers for the customer component."[848] He also shared that NARUC's manual provided an illustrative cost allocation study of the allocation of gas distribution mains using a hybrid allocation factor based on 80 percent peak day and 20 percent on the number of customers. However, Mr. Gorman did not use

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[844] *Id*.

[845] Manuel Rebuttal at 8.

[846] *In re Baltimore Gas and Electric Company*, 79 Md PSC 349 (1988).

[847] Order No. 80460, *In the Matter of the Application of the Baltimore Gas and Electric Company for Revision in its Gas Base Rates*, Case No. 9036, slip op. at 9 (Dec. 21, 2005).

[848] Gorman Direct at 40.

a hybrid approach in his recommendation because he believed the inclusion of any customer component would further exacerbate the subsidies to the residential class.[849] Further, the NARUC manual upon which Mr. Gorman relies does not require that demand costs be allocated using a peak day allocator. Rather, as Staff witness Kuykendall recognized, the NARUC manual itself acknowledges a lack of agreement on this subject. Accordingly, based on the testimony in the record and in view of the Commission's historical precedent, the Commission finds that neither Staff nor DOD has met its burden to establish a sufficient basis for the Commission to deviate from historical practice where BGE is concerned. The Commission, therefore, declines to depart from the current approach used by BGE and accepted in previous BGE cases.

V. Electric Rate Design

A. New BGE Offset Rider (New Rider)

424. All parties in this proceeding agree that the MRP must be designed in a way that takes into account the significant financial hardship that the COVID-19 pandemic has had on many customers as well as the increased reliance and pressure placed on Maryland utilities to ensure reliable service to all customers.[850] Therefore, in order to balance and mitigate the economic impact of COVID-19 with making the necessary capital investments in the distribution system, BGE proposes to offset any increase in the

[849] *Id*. at 42.
[850] BGE Initial Brief at 17-18.

Company's revenue requirements in 2021 and 2022 primarily through the acceleration of certain tax benefits the first two years of the MRP.[851]

425. BGE has not requested, nor is the Commission granting, a rate freeze for BGE's customers. BGE's proposal is to accelerate the use of tax benefits to mitigate immediate rate increases during the first two years of the MRP period. To be clear, BGE has requested, and the Commission is granting, in part, a rate increase. BGE's revenues are in fact increasing in 2021, 2022 and 2023. In designing its MRP proposal, BGE has stated publicly that its customers will not experience any rate increase over the next two years (i.e., a rate freeze). However, the Commission finds that under BGE's proposal, customers will be paying BGE for projected costs starting in 2021 by forgoing the benefit of receiving offsetting credits over a longer time horizon.

426. The Commission also finds BGE's proposal is inconsistent with a major feature of a MRP, which is to provide known rate changes that are spread over multiple years.[852] From a customer's perspective, BGE's proposal freezes rates for at least two years, but creates rate uncertainty in 2024 since the full amount of 2021-2023 rates would take effect along with any future true-ups and new rate proposals at that time.

427. To remedy these shortcomings, the Commission is directing that new rates be established at the beginning of each year with the revenues approved in this Order and 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 established such that the

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[851] *Id*. at 18.

[852] Order No. 89482 at 1.

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.

428. For 2021 (Rate Year 1), the Commission finds that the entire rate increase for electric and gas service shall be avoided to ensure that customers' rates are not raised in the midst of the ongoing COVID-19 pandemic. BGE will be required to file updates to the rider with the informational filing 60 days before the end of the 2021. The Commission will determine at that time the appropriate amount of customer funds from the Tax Cuts and Jobs Act (TCJA) that should be used to offset perceived changes, if any, in rates in 2022 (Rate Year 2) and 2023 (Rate Year 3).

429. 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 electric Rider 25 or gas Rider 8 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 2021 than it is for 2020, except adjusted for the electric Rider 25 or gas Rider 8 forecast.

430. The Commission directs the rider to be listed separately on the customer's bill and be labeled, "BGE Federal Tax Credit." BGE 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 BGE's rate increase in 2021, a feature lacking from BGE's proposal to offset rates. The Commission finds that making the BGE Federal Tax Credit apparent keeps customers informed about changes to their bill while simultaneously shielding them from experiencing a bill increase in the midst of the COVID-19 pandemic.

B. Revenue Allocation

BGE

431. BGE witness Lynn Fiery presented the Company's proposed electric and gas revenue allocations, rate designs and tariff changes for BGE's MRP for the years 2021-2023. Ms. Fiery testified that "BGE is not proposing an increase to electric and gas distribution revenues in 2021 and 2022 and is proposing to increase revenues in 2023…"[853] She proposes specific rates for each customer class that allows the Company to collect the requested revenue requirement proposed by BGE witness Vahos.[854] Consistent with Mr. Vahos' proposal to not increase base rates for 2021 and 2022, Ms. Fiery proposes to maintain the current levels for each electric and gas rate class.[855] However, in Rate Year 3 of the MRP, Ms. Fiery proposes a revenue allocation guided by the results of the ECOSS and GCOSS sponsored by BGE witnesses O'Neill and Manuel, respectively.[856]

432. Ms. Fiery explains that an effective rate design incorporates principles such as cost causation, price signaling, reasonableness, gradualism, and both inter-class and intra-

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[853] Fiery Direct at 2.
[854] *Id*.
[855] *Id*. at 3.
[856] *Id*.

class equity.[857] Ms. Fiery testified that BGE's rate design generally reflects these principles, but "there are certain changes to the current rate design that, if made, would demonstrate a better adherence to these principles."[858] According to the principle of cost causation, costs should be borne by the customers on whose behalf the costs are incurred.

433. BGE's proposed revenue allocation methodology, a two-step revenue allocation approach for electric and gas in this proceeding, is an example of how cost causation is addressed by using the results of a cost of service study to move customer class returns closer to the system average return and thereby having costs be borne by the appropriate customers.[859] BGE's proposed methodology also incorporates the principle of gradualism, whereby rates are moved by incremental steps rather than by drastic changes.[860] Additionally, Ms. Fiery noted that "the Company's rate design should be consistent with the nature of the costs incurred in providing service to customers. In other words, fixed and demand-related costs (or costs that do not vary with the total amount of electricity or gas delivered) should be recovered through fixed monthly rates and rates that reflect a customer's demand on the system, respectively, and variable costs (or costs that increase or decrease as the total amount of electricity or gas delivered changes) should be recovered through rates that do vary based on the total amount of gas delivered to a customer."[861]

434. BGE's basic rate structure includes the use of a Customer Charge, a Demand Price for gas or Demand Charge for electricity, and a Delivery Price for gas or Delivery

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[857] *Id*. at 6.
[858] *Id*.
[859] *Id*.
[860] *Id*.
[861] *Id*. at 7.

Charge for electricity. The Customer Charge is the fixed monthly charge on a customer bill that is intended to recover those operating costs that are caused by customers connecting to the electric or gas distribution system.[862] The Demand Charge is a charge for certain rate schedules based on the maximum load over a measured period of time that is designed to recover the costs driven by customer class' peak loads.[863] The Delivery Service Charge is a volumetric charge meant to recover the costs caused by customers' usage (or those costs which vary as customer usage varies).[864]

435. Ms. Fiery proposed using a two-step revenue allocation approach to apportion BGE's requested revenue increase in Rate Year 3. This approach moves each customer class' rate of return toward or within a reasonable band (+/-10 percent) around the system average rate of return which is consistent with BGE's proposed approach in other recent rate cases.[865]

436. In Step One, Ms. Fiery proposed moving the relative rate of return ("RROR") for classes that are under-earning with an RROR below 0.90 closer to the system average while adhering to the principle of gradualism. Based on the ECOSS recommended by Ms. O'Neill, Schedule R is the only class whose RROR is below 0.90 and therefore Ms. Fiery proposed that Schedule R receive a Step One adjustment moving it 50 percent of the way to the desired band around the system average in Rate Year 3.[866] This results in

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[862] *Id*. at 8.

[863] *Id*.

[864] *Id*. In Footnote 4 of her Direct Testimony, Ms. Fiery explained that "the terms Demand Charge and Delivery Service Charge are used in the Retail Electric Service Tariff and the terms Demand Price and Delivery Service Price are used for Retail Gas Service Tariff. Where the terms Demand Charge and Delivery Service Charge are used in my testimony, the statements also apply to the gas Demand Price and Delivery Price."

[865] Fiery Direct at 12.

[866] *Id*. at 13.

a Step One adjustment for Schedule R that moves the RROR from 0.67 to 0.78.[867] Ms. Fiery testified that in keeping with Commission precedent "to not decrease electric revenues when the overall revenue requirement is increasing, [she does] not propose revenue reductions for those classes that are over-earning by more than 10% of the system average"[868] (based on Ms. O'Neil's ECOSS over-earning rate schedules include Schedules including GS, GL, T and PL).

437. For Step Two, Ms. Fiery proposed that the remaining revenue increase be allocated to existing rate classes in proportion to base distribution revenues, after Step One.[869] However, BGE is not proposing any revenue change for PL and T as their RRORs are already 4.09 and 11.95, respectively, which is about four to 12 times the system average.[870] She also stated that she excluded EVP from receiving a revenue increase.

438. The results of Ms. Fiery's two-step revenue allocation methodology applied to Rate Year 3 of BGE's proposed revenue increase in its Multi-Year Rate Plan are shown in Table 1 below.

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[867] *Id.*
[868] *Id.*
[869] *Id.*
[870] *Id.*

Table 1[871] 2023 Electric Distribution Revenue Increase by Customer Class				
Class	**Step 1**	**Step 2**	**Total**	**% of Total**
R	$21.9	$64.0	$86.0	61.25%
RL	--	$4.6	$4.6	3.28%
G	--	$11.8	$11.8	8.38%
GS	--	$1.0	$1.0	0.69%
GU	--	$0.0	$0.0	0.02%
GL	--	$27.3	$27.3	19.41%
P	--	$7.1	$7.1	5.04%
T	--	--	--	0.00%
SL	--	$2.7	$2.7	1.94%
PL	--	--	--	0.00%
Total	**$21.9**	**$118.4**	**140.4**	**100%**

439. Even with BGE's Step One allocation proposing to allocate the first $21.9 million to Schedule R to bring the residential class closer to the system average, Schedule R is still under-earning, which Ms. Fiery points out is a pattern from BGE's previous five rate cases. Ms. Fiery highlighted in Table 5 of her Direct Testimony the Schedule R relative rates of return[872] from the previous five rate cases.[873] She shows that Schedule R has not seen much improvement in its RROR since 2012. She noted, however, that there was "slight improvement in Case No. 9355 as a result of the Commission's Order in Case No. 9326 which directed that the Schedule R receive a step one increase equal to 50% of the

871 *Id*. at 14. Table 1 above is adapted from Table 4 of the Direct Testimony of Lynn Fiery at 14.

872 Relative Rate of Return (RROR) is interchangeable with and also known as the unitized rate of return (UROR) by some parties in this case. This measure is used as a benchmark for guiding the direction of revenue changes as the rate class level.

873 Fiery Direct at 15.

overall increase."[874] In Case No. 9355, the RROR for Schedule R was 0.75, but since that case the RROR has declined to hover between 0.68 or 0.69.[875] With Schedule R relative rates of return at 0.67 in the current ECOSS, Ms. Fiery proposes a Step One allocation that moves the class 50 percent of the way to a RROR of 0.90.[876]

440. Ms. Fiery also explained that "[a]lthough BGE is not proposing a revenue increase in RY1 and RY2, rate changes will occur in each year to account for the effective delivery rate as a result of Rider 25 adjustments. For each schedule, the weather-adjusted billing determinants forecasted for the particular Rate Year are multiplied by the current rates in effect during that Rate Year to derive revenue at current rates."[877]

Staff

441. Staff witness Thompson testified that, like BGE, she uses a two-step methodology for revenue allocation amongst the rate classes and excludes Schedule PL, T and EVP.[878] However, because she uses the revenue requirement proposed by Staff witness Smith and a different ECOSS as well as an intrinsic difference in methodologies, Ms. Thompson's analysis results in different inter-class allocations.[879]

442. For Step One in the two-step approach, Ms. Thompson allocates a flat 15 percent of the total revenue requirement to all under-earning classes (classes with a relative rate

[874] *Id*.
[875] *Id*.
[876] *Id*.
[877] *Id*. at 16.
[878] Thompson Direct at 26.
[879] *Id*.

of return of less than 95 percent).[880] Using Staff's ECOSS, Schedule R is the only class included in Step One with a relative rate of return of 0.67.[881] Ms. Thompson explained that she uses 15 percent because "it allows Schedule R to move closer to a UROR of 1.0 without causing Schedule G's UROR (0.98) to decrease, while also allocating a sufficient portion of the revenue requirement such that classes with URORs of greater than 1 have the opportunity to move closer to a UROR of 1."[882] Moreover, Ms. Thompson stated that she finds 15 percent to be reasonable because the residential class has been chronically under-earning since at least 2012.[883] In Step Two, Ms. Thompson allocates the remaining revenue requirement to all non-excluded classes based on each class's current revenue as a percentage of total current revenue of all the classes included in Step Two.[884] Similar to BGE witness Fiery, Ms. Thompson excluded Schedules PL and T because they are substantially over-earning even under Staff ECOSS with relative rates of return of 4.11 and 12.61, respectively.[885] Additionally, Schedule EVP is excluded because rates charged to this class are market-based and not established during a rate case.[886]

BGE Rebuttal

443. In her Rebuttal Testimony, BGE witness Fiery disagreed with Staff's proposed Step One increase of 15 percent for Schedule R as -- she argues -- Ms. Thompson's

[880] *Id*.
[881] *Id*.
[882] *Id*.
[883] *Id*. at 26-27.
[884] *Id*. at 27.
[885] *Id*.at 28.
[886] *Id*.

initial allocation does very little to move that class's relative rate of return to the system average.[887]

444. Ms. Fiery argues that Schedule R has been chronically under-earning since at least 2012 and acceptance of Staff's position will only further the under-earning of Schedule R and allow inter-class inequities to persist.[888] Ms. Fiery further stated that her Step One adjustment that "moves Schedule R 50% of the way to a RROR of 0.90 provides for a more meaningful movement towards system parity and is fair to all classes."[889] Moreover, "the MRP provides the Commission with the opportunity to address inter-class subsidies gradually over a three-year period, but if meaningful action is not taken, the subsidies will continue to persist or even increase over the three years."[890] Last, Ms. Fiery objected to Staff's Step Two allocation methodology stating that it "partially negates the Step One allocation" because it allocates the remaining revenue requirement based on the proportion of each class' revenue *at current rates*.[891]

<u>*OPC*</u>

445. OPC witness Mierzwa stated that in developing his proposed electric revenue distribution, he used the same two-step approach used by BGE. That is, in Step One he "moved Schedule R 50 percent toward 90 percent of the system average return and in Step Two, the remaining revenue increase was allocated to each rate class, excluding

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887 Fiery Rebuttal at 3.

888 *Id*. at 4. Ms. Fiery demonstrated the historical rate cases relative rates of return and the Step One Percentage of Revenue Increase in Table 1 of Fiery Rebuttal at 4.

889 Fiery Rebuttal at 5.

890 *Id*.

891 *Id*.

Schedules PL, T and EVP, in proportion to base rate revenues after step one."[892] In her Rebuttal Testimony, BGE witness Fiery testified that she agrees with OPC's two-step approach but warns that its ECOSS should not be relied upon.[893]

DOD

446. DOD witness Gorman claimed that BGE's step one approach (where Schedule R is adjusted 50 percent of the way to the desired bandwidth, which takes BGE's relative rate of return 0.67 percent to 0.78 percent) falls short of meeting BGE's general methodology of adjusting classes' relative rate of return to 90 percent in the Step One increase.[894] Mr. Gorman argued that a stronger movement to cost of service could be absorbed by the residential class in Step One without imposing unnecessary or significant rate shock on this rate class.[895] Therefore, Mr. Gorman proposed to move the residential class, Schedule R, rates to the 90 percent of the cost of service in Step One.[896] Mr. Gorman's proposed modification would require a Step One revenue allocation increase to residential customers of $43.9 million rather than the $21.9 million proposed by BGE.[897] In Step Two, consistent with BGE's proposal, Mr. Gorman allocated the remaining revenue increase across rate classes on a uniform system basis.[898]

BGE Rebuttal

447. In her Rebuttal Testimony, BGE witness Fiery found that the recommendation of Mr. Gorman is reasonable and more aligned with cost causation; however, in

[892] Mierzwa Direct at 19-20.
[893] Fiery Rebuttal at 6.
[894] Gorman Direct at 34-35.
[895] *Id*. at 36.
[896] *Id*.
[897] *Id*.
[898] Gorman Direct at 36.

consideration of gradualism, BGE still supports its recommendation to move Schedule R 50 percent of the way to a relative rate of return of 0.90.[899]

1. Amtrak - Schedule T

448. Amtrak witnesses Stan Faryniarz and Christopher White proposed changes to BGE's ECOSS and revenue allocation to address the excessive cost inequities built into BGE Rate T, which is priced well above cost of service as BGE's ECOSS clearly indicates.[900] BGE Rate Schedule T is a distribution tariff for Transmission Voltage Service, applicable to customers with "…demands of 1,500 kW or more where service is supplied at 115,000 Volts and over." [901] Schedule T applies to just six BGE customers, including Amtrak. As indicated in BGE's ECOSS, Rate T customers in aggregate presently contribute over $4.7 million towards BGE's current distribution revenues of nearly $1.17 billion, about 0.4 percent. Specifically, Amtrak receives power from BGE for its Jericho Park account at 230 kilovolts ("kV"), for use on Amtrak's electric traction system, powering the electric locomotives on the Northeast corridor between Washington, DC and New York, NY.[902] Amtrak's annual expenditure for Rate T service at Jericho Park is almost $690,000, including customer charges, delivery service charges (distribution energy charge), and other riders applicable to Rate T. The portion of Amtrak's annual spend that is exclusive of the riders and is distribution-related is about $357,000, providing about 7.5 percent of Rate T distribution-related revenue to BGE.[903]

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[899] Fiery Rebuttal at 8-9.
[900] Faryniarz Direct at 4.
[901] *Id*. at 5.
[902] *Id*. at 6.
[903] *Id*.

449. Mr. Faryniarz analyzed BGE's relative rates of return from 2010 to 2014 and found that on average Schedule T customers were contributing close to 7 percent more than the systemwide average rate of return.[904] However, in the 2019 BGE ECOSS, the Company's proposed relative rate of return for Schedule T is 11.95 percent, which is even greater than the five year average from 2010 to 2014. Consequently, Mr. Faryniarz recommended that the Commission "correct this chronic inequity by ordering BGE to redesign all of its rates to bring Rate T RROR within the bandwidth of +/- 10% around the system average, that is, to within a 0.9 – 1.1 RROR bandwidth over the three-year rate horizon contemplated in this proceeding."[905]

450. To move Schedule T toward the system average, Mr. Faryniarz proposed to first allocate any reductions to the revenues sought by BGE in this case and approved by the Commission, to Rate T, so that this class contributes at an RROR of no greater than 1.66 by no later than the third year of the BGE 3-year rate plan.[906] If no revenue reductions below the revenues sought by BGE are approved, or if they are insufficient to lessen the RROR for Rate T to no greater than 1.66, Mr. Faryniariz argued the Commission should order BGE to implement minor increases to Rate Schedule R to ensure not only that the Rate T class is left contributing at an RROR no greater than 1.66, but that Rate R is brought marginally closer to parity with the BGE system average rate of return by no later than the third year of BGE's three-year rate plan.[907]

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[904] *Id*. at 14.
[905] *Id*. at 17.
[906] *Id*. at 18.
[907] *Id*.

BGE Rebuttal

451. In her Rebuttal Testimony, Ms. Fiery states that BGE "would not oppose a revenue decrease for Schedule T customers."[908] In fact, she points out that BGE has been supportive of, and proposed, revenue decreases for Schedule T in the past as this class has been significantly over-earning for several years.[909] She also noted that Mr. Faryniarz's proposal would result in "an increase of 0.02 cents/kWh to a residential customer's distribution rate, resulting in an increase to the average residential customer's bill of $0.16/month."[910]

Walmart

452. Walmart witness Alex J. Kronauer stated that "Walmart does not oppose the Company's proposed revenue allocation."[911] However, he recommended that should the Commission approve a revenue requirement less than that proposed by BGE, the reduction should be applied in a manner that moves classes toward system average.

BGE Rebuttal

453. In her Rebuttal Testimony, Ms. Fiery supported moving classes to where costs are borne by appropriate customers but indicated that if there is a reduction in BGE's proposed revenue requirement, the Company proposes that Step Two still allocate the remaining deficiency to all classes based on each class's proportion of revenue after Step One.[912]

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[908] Fiery Rebuttal at 10.
[909] *Id.*
[910] *Id.*
[911] Kronauer Direct at 22.
[912] Fiery Rebuttal at 7.

Commission Decision

454. All parties with the exception of Amtrak endorse a two-step revenue allocation method. BGE proposes using a two-step revenue allocation approach that apportions the proposed revenue increase in 2023 Rate Year 3, such that it moves each customer classes' rate of return toward or within a reasonable band (+/-10 percent) around the system average rate of return (or 1.00). BGE's Step One adjustment moves the residential class (Schedule R) 50 percent of the way to a relative rate of return of 0.90; and its Step Two adjustment allocates the remaining revenue increase in proportion to base distribution revenues, after Step One. However, BGE is not proposing any revenue change for over-earning rate classes PL and T; neither is it proposing a revenue increase for Schedule EVP.

455. OPC supports and uses BGE's proposed revenue allocation. DOD also supports BGE's revenue allocation approach with one modification - allow Step One to move Schedule R fully to 0.90 of the relative rate of return; and its Step Two adjustment is similar to BGE's Step Two. Alternatively, Staff proposes a two-step approach that adjusts Step One by a specific percentage (15 percent) of the proposed revenue increase, and its Step Two adjustment allocates the remaining revenue increase in proportion to base distribution revenues, after Step One. Staff's proposal also excludes Schedules PL, T, and EVP for the same reasons as BGE.

456. Amtrak, unlike the other parties, recommends that the Commission direct BGE to redesign all of its rates to bring Schedule T within the relative rate of return to around + /-

10 percent of the system average over the period of the MRP, or at least to an RROR of 1.66.

457. The Commission has historically accepted the proposed two step approach and approved a specific percentage of the total revenue as the Step One adjustment to all under-earning classes, instead of a fixed dollar amount or the banded method.[913] The Commission finds that setting a specific percentage continues to be appropriate for a Step One adjustment for all classes under a UROR of 1.0 each year and finds 20 percent of the revenue increase of each year of the MRP to be allocated in Step One for under-earning classes (here, Schedule R) is appropriate. This would result in the relative rate of return for the residential class Schedule R to gradually move closer to the system average relative rate of return of 1.00.

458. The Commission will set rates for the MRP period for the next three years based on the following revenue requirements by year.

Table 2

Revenue Requirement for Multi-Year Rate Plan 2021-2023

	Electric
2021	$59,334,000
2022	$38,696,000
2023	$41,879,000

[913] *Id*. at 5. See also Table 1. Historical Rate Case RRORs in the Rebuttal Testimony of Lynn Fiery at 4 showing historical rate case Step One percentage of revenue increase ranging from 15 percent to 50 percent.

459. Additionally, as discussed in the Cost of Service section, the Commission adopts Staff's ECOSS to allocate revenues and a Step One adjustment allocating 20 percent of the revenue increase each year to each class under a UROR of 1.0 after adjusting net operating income each year for the incremental revenue increase. As a result, the relative rate of Schedule R gradually moves closer to the system average rate of return 1.00 over the MRP period starting with 0.68 in the historic test year, 2020, and ending with approximately a 0.78 relative rate of return in 2023 as proposed by BGE. The resulting allocation of revenue per class is presented in the chart below.

Table 3 –
Estimated Relative Rate of Return By Year with a Step One Allocating 20% in Step One to classes under a UROR of 1.0

	R	RL	G	GS	GL	P	SL	P	T	EVP
HTY	0.68	1.04	0.98	1.68	1.61	1.06	1.47	4.11	12.61	(0.88)
2021	0.73	1.01	1.03	1.59	1.51	1.03	1.36	3.50	10.00	(0.75)
2022	0.76	0.99	1.03	1.54	1.45	1.01	1.31	3.20	9.12	(0.69)
2023	0.79	1.00	1.02	1.50	1.41	0.99	1.26	2.92	8.34	(0.63)

Table 4
Revenue Allocated to Each Class by Year with a Step One Allocation of 20% of the Proposed Revenue Increase To classes under a UROR of 1.0

	2021	2022	2023	Total
R	$34,999,386	$24,162,801	$25,679,580	**$84,841,766**
RL	$1,866,906	$1,201,904	$1,858,124	**$4,926,934**
G	$7,223,475	$3,389,644	$3,646,449	**$14,259,569**
GS	$432,174	$278,232	$299,311	**$1,009,717**
GU	$7,231	$3,393	$3,650	**$14,274**
GL	$10,764,592	$6,930,186	$7,455,228	**$25,150,005**
P	$3,221,275	$2,073,839	$2,230,957	**$7,526,071**
T	($200,000)	-	-	**($200,000)**
SL	$1,018,961	$ 656,002	$705,702	**$2,380,665**
Total	**$59,334,000**	**$38,696,000**	**$41,879,000**	**$139,909,000**

460. Amtrak expresses concerns about how BGE's two-step rate design allocation method adheres to the principle of gradualism, but ignores other principles such as interclass inequities and the fundamental principle of cost causation. Amtrak argues that "the record here shows that applying the Commission's 'no decrease if there is an increase' policy universally, with no exceptions, could perpetuate indefinitely the disproportionate RROR for Schedule T."[914] Amtrak proposes the Commission abandon all of the proposed two-step revenue allocation methods proposed by the parties in this case and adopt one that focuses on Schedule T achieving an RROR of 1.66.

461. The Commission acknowledges that Schedule T is significantly over-earning and that the MRP gives the Commission an opportunity to begin to explore measures that would curtail Schedule T's over-contributing to the revenue allocation. Based on the

[914] Amtrak Initial Brief at 4.

record however, the Commission cannot grant a full reduction of Schedule T's RROR to 1.66. A simple review of BGE's ECOSS presented in Exhibit No. SCF-3 of Amtrak witness Faryniarz shows the required reduction in Schedule T's revenue to achieve an RROR of 1.0 is $2.9 million.[915] Schedule T's distribution revenue recovered from base rates which are being set in this proceeding are approximately $2.3 million which means the Commission would have to reduce Schedule T's distribution rates to effectively zero (or negative) to achieve Amtrak's outcome.[916]

462. Although the current record does not support the Commission accepting Amtrak's proposal in full, it does provide strong support for some relief to be granted. Therefore, the Commission directs BGE to remove $200,000 of distribution revenues in Step One from Schedule T and directs BGE to examine what costs, riders, surcharges, or other revenue streams are driving the significant over-earning by Schedule T relative to other schedules. BGE is directed to include the results of its analysis in its 2021 Annual Informational Filing.

Bill Impact Summary

463. Since the Commission has directed a 100 percent offset of revenues in 2021, no rate impact should be different for 2021 than it is for 2020, except adjusted for the BSA forecast. Therefore, under a scenario deferring the rate increase for 2021 only, the Schedule R relative rate of return is 0 percent and the average residential bill increase is $0.00 in 2021. See the charts below.

[915] Subtract lines 37 from line 16.
[916] Fiery Rebuttal at BGE Exhibit LFK-2 Rebuttal Sheet E-11 at 1 – 3.

Resulting Bill Impacts[917]

Average Residential Bill Impact						
	Electric Customer		Gas Customer		Electric & Gas Customer	
	$	%	$	%	$	%
2021	-	0.00%	-	0.00%	-	0.00%
2022	$4.40	9.85%	$4.77	8.96%	$8.24	9.48%
2023	$1.88	3.84%	$0.71	1.16%	$2.07	2.19%

C. Intra-Class Rate Design Issues

1. Customer Charge

<u>BGE</u>

464. BGE witness Fiery proposed a gradual increase to the fixed Customer Charge in Rate Year 3 for four of the eight electric rate classes including residential (Schedule R), general services small (Schedule G), general service large (Schedule GL), and primary voltage (Schedule P).

465. Regarding Schedule R, Ms. Fiery noted the purpose of the proposed customer charge increase is to move the fixed recovery closer to the level supported by BGE's 2019 ECOSS.[918] The current customer charge for Schedules R and RL are $8.00 and $12.00, respectively.[919] Ms. Fiery testified that her proposal aims to reduce the difference in the distribution rates between Schedule R and Schedule RL (non-TOU and TOU). BGE believes that Schedules R and RL should ultimately have the same distribution rates but, adhering to the principles of gradualism, Ms. Fiery proposed to

917 As noted above in the New BGE Offset Rider section, the Commission reserves the right to determine whether to apply additional offsets in 2022 and 2023.
918 Fiery Direct at 18.
919 *Id.*

move towards equivalent distribution rates for the R/RL classes by gradually increasing the customer charge for Schedule R towards the level supported in the 2019 ECOSS for the combined Schedule R/RL class of $17.03.[920] Ms. Fiery stated that since Schedule RL is already significantly closer to ECOSS-supported level of the cost for a combined R/RL class, she proposes no change to its customer charge in this case. Ms. Fiery proposed that a customer charge increase to $9.00 would be appropriate for Schedule R in Rate Year 3 (2023).

466. Regarding Schedule G, Ms. Fiery proposed to increase the customer charge to move it closer to the current level of the customer charge for Schedule GS and the ECOSS supported level to move the G and GS rate closer to alignment on Rate Year 3 of the MRP.[921] The current customer charges for Schedules G and GS are $12.40 and $18.60, respectively. Ms. Fiery proposes that Schedule G customer charge be increased in 2023 to bring it closer to Schedule GS. Therefore, the customer charge for Schedule G, as proposed, will increase from $12.40 to $14.00.[922]

467. Regarding Schedule GL, Ms. Fiery proposed to increase the customer charge from $88.00 to $97.00 and then recover approximately 55 percent of the remaining revenue increase via the Demand Charge, and 45 percent via the Delivery Service Charge for Rate Year 3.[923] Regarding Schedule P, Ms. Fiery proposed to increase the customer charge from $600.00 to $660.00, with the remaining revenue recovered approximately 55

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[920] *Id*.
[921] *Id*. at 24.
[922] *Id*.
[923] *Id*. at 25.

percent via the Demand Charge and 45 percent via the Delivery Service Charge.[924] She noted that "this allocation improves the overall rate design by increasing the demand-related revenue to more closely follow the ECOSS."[925] The table below displays Ms. Fiery's proposals for customer charges by customer class.

Table 5

Rate Year 3 (2023) Customer Charge Proposal for Electric Rate Design

Class	Cost	Current	RY1	RY2	RY3
Schedule R	$17.03	$8.00	$8.00	$8.00	$9.00
Schedule G	$28.57	$12.40	$12.40	$12.40	$14.00
Schedule GL	$117.18	$88.00	$88.00	$88.00	$97.00
Schedule P	$1196.90	$600.00	$600.00	$600.00	$660.00

468. Ms. Fiery described the impact of the proposed increases to the customer charge in these designated rate classes on the average residential electric customer using 839 kWh per month to be economically neutral.[926] "In other words, based upon the proposed revenue increase, a customer would receive the same increase to their bill in RY3 whether my proposed Customer Charge and volumetric Delivery Service Charge rate design is accepted or whether the full RY3 increase is assigned to volumetric Delivery Service Charge."[927] She further argued that "an increase in the Customer Charge has minimal impact on the percentage of the total average residential customer bill that would

[924] *Id*. at 26.
[925] *Id*.
[926] *Id*. at 19.
[927] *Id*.

be recovered through volumetric as opposed to fixed charges."[928] BGE argued that the fixed customer charge that Ms. Fiery proposed would not have a meaningful impact on the price signals encouraging energy conservation received by residential customers.[929]

Staff

469. Staff witness Thompson proposed a residential class customer charge of $8.26 (the current customer charge is $8.00). Consequently, Staff opposed BGE's proposed residential class customer charge of $9.00. Ms. Thompson argued that BGE witness Fiery's 12.5 percent increase to the residential class customer charge "does not align with past precedent nor with gradualism."[930] Ms. Thompson points out that the Commission has not approved a residential customer charge increase greater than 5.33 percent in the past six rate cases.[931]

470. In evaluating an appropriate residential class customer charge increase, Ms. Thompson stated she "sought to balance three factors: Commission precedent, gradualism, and policy goals."[932] She opined that "[o]ver the past six rate cases, Commission precedent shows that the Commission has approved two increases to the Residential customer charge: an increase of 5.33 percent in Case No. 9406 and an increase of 1.27 percent in Case No. 9610."[933] She also pointed out that in Case No. 9424 the Public Utility Law Judge approved a 19.5 percent increase in the residential customer charge; which was deemed excessive by the Commission, and rejected by the

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928 *Id*. at 20.
929 *Id*. at 21.
930 Thompson Direct at 28.
931 *Id*.
932 *Id*.
933 *Id*. at 28-29.

Commission, which instead granted a 2.84 percent increase to the residential customer charge.[934] Additionally, Ms. Thompson noted that in the past two rate cases, Case No. 9406 and Case No. 9610, BGE requested customer charge increases of 60 percent and 27 percent, and the Commission granted increases of 5.33 percent and 1.27 percent, respectively.[935] Regarding Commission policies, Ms. Thompson stated that "in Order No. 88033, the Commission notes that 'relatively low customer charges provide customers with greater control over their electricity bills by increasing the value of volumetric charges.'"[936] Based on these factors, Ms. Thompson proposed that the customer charge should be computed taking the average of the customer charge increases from the past six cases where the increase was approved, which equals 3.30 percent.[937] She recommended that "a residential customer charge increase of 3.30 percent incorporates and balances the factors of Commission precedent, gradualism, and Commission Policy."[938]

471. Regarding moving Schedule R customer charge closer to Schedule RL, Ms. Thompson agreed with BGE's proposal to not increase Schedule RL's customer charge.[939]

472. Ms. Thompson's approach for determining the customer charge for Schedule G is the same as for Schedule R where she averaged the customer charge for the past six cases where an increase was approved. The average of the two increases is 3.85 percent, which

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[934] *Id*. at 29.
[935] *Id*.
[936] *Id*.
[937] *Id*. at 30.
[938] *Id*.
[939] *Id*. at 32.

Ms. Thompson proposed to use as the customer charge percent increase for Schedule G and Schedule G Primary.[940] Staff therefore recommended that the customer charge for Schedule G and Schedule G Primary would increase from $12.40 to $12.88.[941]

473. Staff proposed no increase to the customer charge for Schedule GU and Schedule GS.[942]

474. Ms. Thompson acknowledged that it is not customary to allow rate increases of the magnitude being proposed in the present rate case.[943] It would have been expected for an MRP to have the rate increase spread over the multi-year period in order to avoid rate shock in the final year. However, due to the current COVID-19 pandemic, BGE does not propose rate increases in the first two years of the MRP in the present case in order to alleviate the difficulty customers may have during this time to pay utility bills. Ms. Thompson agreed that spreading the revenue requirement over the three years will result in lower rate increases each year, but customers' bills would increase in Year 1 and Year 2 when customers would be experiencing the most economic hardship. In Year 3, Staff anticipates that the economic effects of the COVID-19 pandemic will have subsided and therefore Staff recommended that it would be appropriate to consider increases only in Year 3 of the MRP.[944]

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[940] *Id*. at 35.
[941] *Id*.
[942] *Id*. at 33.
[943] *Id*. at 41.
[944] *Id*.

BGE Rebuttal

475. Overall, BGE witness Fiery disagreed with Ms. Thompson's proposed customer charge increases for Schedules R and G.[945] Ms. Fiery asserted that the proposed increases are too small and argued that "[i]f Staff Witness Thompson is using past precedent as its guide in proposing Customer Charge increases, she should use the highest percentage increase in prior cases not an average. Eliminating the percent increases from Case No. 9610 from Staff's analysis results in one remaining increase of 5.33% for Schedule R and 5.22% for Schedule G from Case No. 9406."[946] Additionally, Ms. Fiery stated that she would recommend the resulting customer charge be rounded to the nearest dime consistent with BGE's current and historical customer charges.[947]

476. Staff witness Thompson continued to support her position on Schedule R and Schedule G claiming her proposal balances past rate increases that customers have experienced with gradualism, while also honoring the Commission's goals of incentivizing greater consumer rationing and increased customer control of bills through larger volumetric increases.[948]

OPC

477. Mr. Mierzwa asserted that "[o]nly the direct costs associated with adding or removing a customer to BGE electric or gas distribution system should be recovered through the fixed monthly customer charge. For electric customers, this would include the investment and expenses associated with line transformers, service lines, metering,

[945] Fiery Rebuttal at 12.
[946] *Id*.
[947] *Id*.
[948] Thompson Surrebuttal at 6 – 7.

billing, and collecting. For gas customers, this would include the investment and expenses associated with service lines, metering, billing, and collecting."[949]

478. Mr. Mierzwa opposed BGE's proposal to increase the Schedule R monthly customer charge and deemed it unreasonable.[950] He claimed the proposed increase is inconsistent with Commission policy,[951] highlighting Commission precedent and policy to minimize customer charge increases.[952] Mr. Mierzwa estimated the direct customer-related costs associated with serving a customer under Schedule R is $7.36, which is less than the current monthly charge of $8.00. OPC argued, therefore, that the Schedule R monthly customer charge should not be increased.[953] In her Rebuttal, BGE witness Fiery disagreed with OPC's position.[954]

Commission Decision (Customer Charge)[955]

479. In addition to changes in the distribution rates, BGE proposes to increase customer charges in four rate classes – Schedules R, G, GL and P – in Rate Year 3. Staff proposes smaller increases in the same four rate classes as BGE beginning in Rate Year 3. OPC proposes no increase in the residential class and makes no recommendation on the other rate classes. The chart below summarizes the proposed customer charge increase in Rate Year 3.

[949] Mierzwa Direct at 24.
[950] *Id*. at 26.
[951] *Id*.
[952] *Id*. at 23.
[953] *Id*. at 26.
[954] Fiery Rebuttal at 15.
[955] Commissioner Richard filed a dissenting statement on this issue.

Table 6 Proposed Customer Charge Increase in Rate Year 3				
Rate Class	**Current Customer Charge**	**BGE Proposed Customer Charge**	**Staff Proposed Customer Charge**	**OPC Proposed Customer Charge**
Schedule R	$8.00	$9.00	$8.26	$8.00
Schedule G	$12.40	$14.00	$12.88	
Schedule GL	$88.00	$97.00	$92.84	
Schedule P	$600.00	$660.00	$634.80	

480. In considering increases to customer charges, the Commission is mindful of public policy goals that are intended to encourage energy conservation, and give customers more control over their bills by increasing the volumetric charge. BGE witness Fiery's Rebuttal Testimony shows a chart[956] of the historical changes in BGE's customer charge since 2011. The chart shows that customer charges have moved very slightly since 2011.[957] Some of the rate classes have only had two increases over the past nine years. Based on the record in this case, the Commission finds that BGE's proposed Schedule R increase is reasonable. This decision appropriately balances cost causation against the principle of gradualism, while continuing to provide an incentive for customers to conserve and have more control over their bills. The Commission notes these proposed increases are still below the customer costs from BGE's ECOSS. Accordingly, the Commission directs BGE to set the new customer charges to become effective January 1, 2022 since the Commission is offsetting all changes in rates with the new rider in 2021.

[956] Fiery Rebuttal at 13, referring to Table 2 Historical Customer Charges.
[957] *Id*.

481. Moreover, as demonstrated in Table 7 of BGE witness Fiery' Direct Testimony, the proposed increase in customer charge "has minimal impact on the percentage of the total average residential customer bill that would be recovered through volumetric as opposed to fixed charges."[958]

Table 6-1

Summary of Exhibit LFK-1[959]

Comparison of Bills for Average Electric Schedule R Customers	**Bill at Current Rates**	**Proposed Bill with increased Customer Charge**	**Proposed Bill without increased Customer Charge**
Total Charges	$107.07	$113.35	$113.35
% of Fixed Total Charges	8%	8%	7%
% of Variable Total Charges	92%	92%	93%

482. The table shows and the Commission finds that there is virtually no difference in a customer's bill with the increase in customer charge for the average residential customer. Therefore it will have no impact on energy conservation or state incentives to reduce energy use.

483. For the non-residential classes proposed increases (Schedules G, GL and P), the Commission also accepts BGE's proposed customer charge increases for all classes and notes that none of the industry parties objected to the proposed customer charges for the non-residential classes. The Commission directs that BGE set the new customer charges

[958] *Id*. at 20.
[959] This table is adapted from Table 7 in BGE witness Fiery's Direct Testimony at 20.

to become effective January 1, 2022 since the Commission is offsetting all changes in rates with the new rider in 2021.

2. Schedule GL and Schedule P

BGE

484. For rate schedules with demand charges, BGE witness Fiery proposed, after increasing the customer charges, to "recover 55 percent of the remaining revenue increase via the Demand Charge."[960] Ms. Fiery did this for both Schedule GL and Schedule P, arguing that her proposal "improves the overall rate design by gradually increasing the demand-related and customer-related revenue to more closely follow the ECOSS."[961] Ms. Fiery's changes in demand charges for Schedules GL and P result in an 18.1 percent increase in the Schedule GL Secondary Demand Charge, a 19 percent increase in the Schedule GL Primary Demand Charge, and a 12.1 percent increase in the Schedule P Demand Charge.[962]

485. Schedule GL has both a primary and a secondary service. Ms. Fiery explains that the rates charged for the primary service have historically been set at 96 percent of the secondary service; her proposal is expected to reflect the same relationship in Rate Year 3.[963]

Staff

486. For classes with demand charges, Schedule GL and Schedule P, Staff witness Thompson proposed to "increase the Customer Charge, Demand Charge and Distribution

[960] *Id*. at 25.
[961] *Id*. at 25 – 26.
[962] Thompson Direct at 19.
[963] *Id*. at 18.

charge for each class in such a way that each charge continues to recover the same percentage of the class's revenue requirement as it currently does."[964]

487. Ms. Fiery testified that she did not agree with Staff's position on maintaining the same proportion of revenues be collected from the Customer Charge as compared to the Delivery Service Charge and Demand Charge as in the test year, because it "will result in no impact in moving the proportion of revenues recovered from the Customer Charge towards the levels supported in the ECOSS."[965] Ms. Fiery presented an analysis to show that the proposed allocation for demand charges does not result in "drastic changes in bill impact across the class."[966]

488. Staff witness Thompson, after considering Ms. Fiery's Rebuttal Testimony agreed to adopt the revenue allocation between demand and volumetric charges and also agreed to adopt the percentage split between primary and secondary rates for Schedule GL.[967] Staff did not change its position regarding customer charges.[968]

Walmart

489. Walmart witness Kronauer expressed concerns that BGE's proposed Schedule GL rate design does not reflect the underlying cost of service and shifts responsibility within the rate class by charging customers for higher-demand related costs through energy charges.[969] Mr. Kronauer argued that BGE's proposal violates cost causation principles. Specifically, he explained that "two customers can have the same level of demand and

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[964] *Id*. at 36.
[965] Fiery Rebuttal at 13.
[966] *Id*. at 20 – 21.
[967] Thompson Surrebuttal at 11.
[968] *Id*.
[969] Kronauer Direct at 24.

cause the utility to incur the same amount of fixed cost, but because one customer uses more kWh than the other, that customer will pay more of the demand costs than the customer that uses fewer kWh." Mr. Kronauer contends "higher load factor customers are paying for a portion of the demand-related costs that are incurred to serve lower factor customers simply because of the manner in which the Company collects those costs in rates."[970]

490. Walmart recommended the Commission accept BGE's proposed customer charge for Schedule GL and allocate the remaining revenue increase to the demand charge. Witness Kronauer testified that for Schedule GL Secondary "this would result in a demand charge of $5.08/kW versus the Company's proposed demand charge of $4.50/kW, and for Schedule GL Primary this would result in a demand charge of $4.58/kW."[971] In the alternative, Walmart recommended that if the Commission approves a lower revenue requirement for Schedule GL than that proposed by BGE, then the Commission should set the customer and demand changes equal to the levels proposed by Walmart at BGE's proposed revenue requirement.[972] BGE Witness Fiery disagreed with this approach because "it is not gradual enough."[973]

491. In his Rebuttal Testimony, Mr. Kronauer recommended that the Commission reject Staff's proposal for Schedule GL, which maintains the existing GL rate structure and spreads the revenue requirement increase such that each charge continues to recover

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[970] *Id*. at 24-25.
[971] *Id*. at 27.
[972] *Id*. at 28.
[973] Fiery Rebuttal at 19.

the same percentage of the class's revenue requirement as before.[974] Specifically, Mr. Kronauer noted that Staff proposes a 5.50 percent increase to customer charges, a 4.93 percent increase to demand charges. and a 4.92 percent increase to distribution charges.[975]

<u>Commission Decision (Schedules GL & P)</u>

492. BGE proposes, after increasing the Customer Charge, to allocate 55 percent of the remaining revenue increase via the Demand Charge, and 45 percent via the Delivery Service Charge for Rate Year 3 for both Schedule GL and Schedule P.[976] Initially, Staff opposed BGE's proposal and argued to maintain the same relationship between the Customer Charge, Demand Charge and Delivery Service Charge as currently exists[977] that is each charge continues to recover the same percentage of the class's revenue requirement as it currently does.[978] However, in Surrebuttal Testimony, Staff witness Thompson stated that, after having reviewed cases cited by BGE supporting its proposal, she updated Staff's allocation position for the Demand Charge and Delivery Service Charge for Schedule GL and Schedule P to be the same as BGE.[979] Walmart also recommended that BGE's proposed customer charge for Schedule GL be accepted but wanted to allocate all of the remaining revenue after the customer charge to the demand

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[974] Kronauer Rebuttal at 3.
[975] *Id*.
[976] Fiery Rebuttal at 18.
[977] *Id*. at 19.
[978] Thompson Direct at 36.
[979] Thompson Surrebuttal at 11.

charge between Schedule GL Primary with a Demand Charge of $4.58/kW and Schedule GL Secondary with a Demand Charge of $5.08.[980]

493. The Commission supports increasing the demand charges to better align with cost causation. Walmart's proposal is not gradual enough and BGE's proposal, which is supported by Staff, did not go far enough to properly align cost causation. Therefore, the Commission directs that BGE allocate the incremental revenue after the customer charge, giving 70 percent to demand and 30 percent to delivery each year. The Commission finds that this strikes the proper balance and is consistent with Case No. 9326, where BGE witness Cloyd recommended "recovering 70 percent of the remaining revenue requirement through demand charge and 30 percent through delivery charge for [Schedule GL and Schedule P]," which was adopted by the Commission in Order No 86060.[981]

3. Schedule SL

BGE

494. For Schedule SL, BGE proposed to allocate 85 percent of the revenue increase to the Delivery Service Charge and 15 percent to the facilities charges (cable, lamp fixtures and poles) and maintenance changes in Rate Year 3.[982] BGE noted out that in recent cases the Schedule SL Delivery Service Charge has received some reductions causing current rates to recover only 3 percent in Delivery Service Charge. BGE's proposal will

[980] Kronauer Direct at 27.
[981] Order No. 86060 at 101, 104-105
[982] Fiery Direct at 27.

cause the Delivery Service Charge to recover 12 percent of Schedule SL revenues in RY3.[983]

Staff

495. Staff witness Thompson opposed BGE's proposal, stating that she is following the precedent of Case No. 9610 and proposes that 27 percent of the revenue allocation is assigned to the Delivery Service Charge so that it results in a $/lamp-watt rate increase of about 35.8 percent.[984]

Commission Decision

496. As Staff points out in its Reply Brief, for the Schedule SL class, BGE recommends an increase of 276.34 percent over current rates, which were established in Case No. 9610.[985] While BGE's position implies that the current rates which grew out of the Settlement agreement is not an appropriate starting point, the Commission finds these are the rates that have been in effect since the settlement and are a good basis to derive future rates. Therefore, the Commission accepts Staff's proposal as it adheres more closely to the principle of gradualism.

4. Tariffs and Riders

a. Rider 16

497. BGE's proposed new Rider 16 (previously reserved for future use) for any potential MRP adjustments that may be ordered by the Commission. As proposed, Rider 16 states that BGE shall file Annual Information Filings and a Final Reconciliation

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983 *Id*.

984 Thompson Direct at 37-38.

985 Staff Reply Brief at 30.

following the conclusion of the MRP pilot rate effective period, as required by Order No. 89482.[986]

> "These filings shall provide imbalances between the Commission approved future test year revenue requirements and actual rate base and operating income. In accordance with Order No. 89482, Rider 16 states that if an Annual Filing imbalance represents an amount owed to customers the Commission may utilize Rider 16 to return an imbalance to customers. Additionally, as proposed, Rider 16 states that the rider can be used to return or recover imbalances from the Final Reconciliation and that all imbalances shall be placed into a regulatory asset or liability, with carrying costs only for amounts owed to customers consistent with Order No. 89482. Finally, the proposed rider language states that the rider rate will be determined for each rate class by allocating the imbalance in a manner determined appropriate by the Commission in proportion to each class's distribution revenues in the final year of the [MRP] and then added to rates based on estimated billing determinants, as approved by the Commission."[987]

498. Staff witness Thompson is concerned that there is a potential internal inconsistency between stating that the Commission will determine the allocation method and that imbalances will be allocated in proportion to distribution revenue in the final year of the MRP.[988] Additionally, the language may prejudge how to allocate any imbalance, which the Commission clearly states in paragraph 79 of Order No. 89482 will be determined on a case-by-case basis.[989] Ms. Thompson therefore recommended that the first sentence in the subsection Calculation of Rate be edited to remove the phrase "in

[986] Thompson Direct at 23.
[987] *Id*. at 24.
[988] *Id*.
[989] *Id*.

proportion to each Schedule's amount of base distribution revenues in the final year of the [MRP]."[990]

Commission Decision (Tariffs & Riders)

499. The Commission accepts Staff's proposed tariff language to Rider 16. Specifically, the first sentence in the subsection Calculation of Rate shall be edited to remove the phrase 'in proportion to each Schedule's amount of base distribution revenues in the final year of the MRP.'[991] The Commission agrees with Staff that the language could be interpreted to prejudge the allocation of an imbalance and declines to adopt BGE's tariff language because it is inconsistent with the intent and language of Order No. 89482.

500. Regarding Rider 25, Staff noted that BGE's proposed changes are consistent with the existing monthly Rider 25 filings, adjusted to account for the fact that future rate years are set based on forecast bill determinants.[992] The Commission accepts BGE's proposed changes to future monthly billing and finds them consistent with the current Rider 25 monthly filing. However, as suggested by Staff, the Commission will review the issue in the future, in the event Rider 25 mechanism is impacted in unforeseen ways by using forecasted billing determinant.[993]

501. Regarding Rider 32, BGE states that recent changes to COMAR 20.62 require additional changes to Rider 32, which the Company will file separately with the

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[990] *Id*. at 42.
[991] *Id*.
[992] *Id*.
[993] *Id*.

Commission.[994] The Commission also accepts BGE's withdrawal of the proposed tariff changes on Tariff Page 53b where the Company is adding section 3B Maintenance (Reactive Only) in this MRP filing and expects the Company to file these proposed tariff revisions in a separate tariff filing process.[995]

VI. Gas Rate Design

A. New BGE Offset Rider Proposal (New Rider)

502. The Commission adopts the same position for the creation of a new Offset Rider as discussed in the Electric Rate Design Section.

B. Revenue Allocation

BGE

503. BGE witness Fiery stated that "Similar to the electric revenue allocation, she proposes to apportion the revenue increase in [Rate Year 3] such that each customer class' rate of return moves toward or within a reasonable band (+/-10% around the system average rate of return."[996] She also proposed the use of the two-step approach described above in the Electric Rate Design section.

504. In Step One, Ms. Fiery proposes to move the RROR for classes that are under-earning with a RROR below 0.90 closer to the system average. [997] Ms. Fiery identified Schedule IS as the only class below the 10 percent band around the system average with a RROR of 0.81; therefore, she recommended a Step One adjustment that moves it to a RROR of 0.90. Although Schedules EG and PLG are over earning by more than 10

[994] *Id*. at 43.
[995] *Id*. at 42-43.
[996] Fiery Direct at 29.
[997] *Id*.

percent of system average, BGE does not propose Step One revenue reductions for those classes in order to be consistent with the Commission's general precedent to not decrease gas revenues allocated to an individual customer class when the overall total revenue requirement is increasing.[998]

505. In Step Two, Ms. Fiery recommended that the remaining proposed revenue increase be allocated to the customer classes in proportion to the adjusted historical year base distribution revenues, with two exceptions.[999] As Schedule PLG is closed to new customers and continues to significantly over-earn at eight times the system average, Ms. Fiery proposed that none of the revenue increase be allocated to that schedule. She also proposed to exclude Schedule EG from receiving a revenue increase in this case since Schedule EG customers are also significantly over-earning at about four-and-a-half times the system average.[1000]

506. The results of applying Ms. Fiery's two step revenue allocation approach to BGE's proposed 2019 GCOSS is displayed below.

Table 7[1001]
2023 Gas Distribution Revenue Increase by Customer Class

Class	Step 1	Step 2	Total	% of Total
D	- -	$63.8	$63.8	67.23%
C	- -	$25.3	$25.3	26.62%
IS	$1.0	$4.4	$5.4	5.73%
ISS	- -	$0.4	$0.4	0.42%
EG	- -	- -	- -	- -
PLG	- -	- -	- -	- -
Total	**$1.0**	**$93.9**	**$94.9**	**100%**

[998] *Id*.
[999] *Id*.
[1000] *Id*.
[1001] *Id*. at 30.

507. Although BGE is not proposing a rate increase in RY1 or RY2, rate changes will occur each year to account for the effective delivery rate as a result of Rider 8 (Monthly Rate Adjustment) and Rider 12 (Gas Administrative Charge) adjustments.[1002] Specifically, Rider 12 recovers certain commodity-related costs that were included in the base distribution revenue requirement ultimately determined in BGE's most recent gas rate case, Case No. 9610, and will recover similar commodity-related costs included in the revenue requirement calculated in this case.[1003] In addition, Rider 8 target revenues that were reduced by the amount recalculated under Rider 12 based upon the Case No. 9610 test year data. The result is a decrease in Rider 8 target revenue and an increase in gas commodity rates.[1004]

Staff

508. Staff witness Afton Hauer proposed a Step One revenue allocation of 15 percent to all under-earning classes which are Schedule C and Schedule IS.[1005] The goal of Staff's recommended rate design proposal is to gradually move all customer classes toward a UROR of 1.0. Since Schedules PLG and EG are greatly over-earning, Ms. Hauer excluded these classes from additional allocation and proposed they not receive any additional revenue.[1006] Additionally, "since Schedule ISS is just above the optimum UROR of 1.0 and has a low Revenue to Rate Base ratio," Ms. Hauer "chose to allocate an

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[1002] *Id*. at 31.
[1003] *Id*.
[1004] *Id*.
[1005] Hauer Direct at 15.
[1006] *Id*. at 15.

additional $50,000 to Schedule ISS in Step Two to prevent the class's UROR from dropping below 1.0."[1007]

OPC

509. OPC witness Mierzwa, using the results of his GCOSS and BGE's proposed revenue requirement, agreed with BGE witness Fiery's two-step revenue allocation methodology and has used the same approach, recommending in Step One to move Schedule IS 90 percent toward the system average return, and in Step Two allocating the revenue to all classes in proportion to the base rate revenues after the Step One increase, excluding EG and PLG.[1008]

DOD

510. DOD witness Gorman proposed to allocate the gas revenue increase using a two-step approach but recommended a revenue allocation that is more in line with his adjusted gas cost of service study.[1009] Under his revenue allocation, he proposed that Schedules D and C receive a first step increase to move their RRORs to 0.90.[1010] He also proposed, in the first step, to reduce Schedule EG's revenues by 10 percent of their revenue at current rates. Mr. Gorman -- in Step Two – allocated the remaining revenue requirement to Schedules D, C, PLG, and ISS using each class's revenues after the Step One allocation.[1011] Schedules IS and EG are excluded from a Step Two increase under Mr. Gorman's proposal.[1012]

[1007] *Id*.
[1008] Mierzwa Direct at 21; Fiery Rebuttal at 25.
[1009] Fiery Rebuttal at 25.
[1010] *Id*.
[1011] *Id*.
[1012] *Id*.

511. Mr. Gorman also stated that BGE's proposed increase for Schedule IS not in line with what BGE proposed for electric rate schedules, specifically Schedule R, which is even further from the system average but received a lower increase relative to the system average increase required in BGE's cost of service study to move the class to parity as compared to Schedule IS.[1013]

512. In her Rebuttal Testimony, Ms. Fiery stated that BGE does not oppose DOD's proposal to provide a Step One decrease of 10 percent of revenue at current rates (or $609,009) to Schedule EG as this class is over-earning with an RROR of 4.62 based on BGE witness Manuel's GCOSS. However, BGE opposed Mr. Gorman's overall revenue allocation methodology because it uses the results of his adjusted GCOSS for the basis of the proposed allocations which is rejected by BGE witness Manuel in his Rebuttal Testimony. Consequently, Ms. Fiery stated that she could not support making rate design decisions based on those results at either BGE's proposed revenue requirement or any other revenue requirement awarded by the Commission.[1014]

<u>Commission Decision (Revenue Allocation)</u>

513. All parties use a two-step revenue allocation method. BGE proposes using a two-step revenue allocation approach that apportions the proposed revenue increase in Rate Year 3 such that it moves each customer class' rate of return toward or within a reasonable band (+/-10 percent) around the system average rate of return (or 1.00). BGE's banded approach results in the Company identifying only one rate class, Schedule IS, as being eligible for a Step One increase and Step Two allocates the remaining

[1013] *Id*. at 25-26.
[1014] *Id*. at 26.

revenue increase in proportion to base distribution revenues after Step One except for excluded classes.

514. Staff's approach identifies both Schedule C and IS as falling below the system wide relative rate of return and eligible for a Step One increase for which Staff uses a specific percentage (15 percent) of the proposed revenue increase and its Step Two adjustment allocates the remaining revenue increase in proportion to base distribution revenues, after Step One.

515. The Commission will set rates for the MRP period for the next three years based on the following revenue requirements for gas.

Table 8

Revenue Requirement for Multi-Year Rate Plan 2021-2023

	Gas
2021	$53,246,000
2022	$10,769,000
2023	$9,872,000

516. The Commission finds that setting a specific percentage continues to be appropriate for a Step One adjustment and finds 15 percent of the revenue increase of each year of the MRP to be allocated in Step One for under-earning classes (here, Schedule C and Schedule IS) is appropriate. This will result in movement of the relative rate of return for Schedule C and Schedule IS closer to the system average relative rate of return of 1.00. The chart below shows the RROR for each rate class for the MRP after applying Staff's Step One allocation.

Table 8.1 Relative Rate of Return By Year with a Step One Allocating 15% of the Proposed Revenue Increase To Schedules C and IS						
	D	**C**	**PLG**	**IS**	**ISS**	**EG**
HTY	1.03	0.88	8.31	0.92	1.03	4.53
2021	1.00	0.95	6.49	0.96	0.96	3.54
2022	1.00	0.96	6.22	0.96	0.97	3.39
2023	1.00	0.97	5.98	0.97	0.97	3.27

Table 9 Revenue Allocated to Each Class by Year with a Step One Allocation of 15% of the Proposed Revenue Increase To Class Under a UROR of 1.0				
	2021	**2022**	**2023**	**Total**
D	$31,033,188	$6,195,592	$5,664,985	**$42,893,765**
C	$18,583,747	$ 3,809,229	$3,504,057	**$25,897,033**
PLG	-	-	-	**-**
IS	$3,433,227	$703,730	$647,352	**$4,784,310**
ISS	$195,838	$60,449	$55,606	**$311,892**
EG	-	-	-	**-**
Total	**$53,246,000**	**$10,769,000**	**$ 9,872,000**	**$73,887,000**

C. Customer Charge

BGE

517. BGE witness Fiery proposed an increase to the fixed customer charge in Rate Year 3 for the Schedule D, Schedule C, and Schedule ISS gas rate classes, in order to move the fixed cost recovery for these classes closer to the level supported by the 2019 GCOSS.[1015] Ms. Fiery testified that the customer charges for these classes were all increased slightly in Case No. 9610, but there continues to be a gap between the current

[1015] Fiery Direct at 32.

customer charge and the level supported by the 2019 GCOSS as shown in the table below.

Table 10[1016] **BGE Customer Charge Proposal**					
Customer Class	**Cost**	**Current**	**RY1**	**RY2**	**RY3**
D	$24.73	$14.25	$14.25	$14.25	$15.25
C	$105.15	$14.25	$14.25	$14.25	$38.00
ISS	$704.90	$363.50	$363.50	$363.50	$375.00

518. Ms. Fiery testified that the proposed increase in customer charge would not have much impact on an average Schedule D customer using 56 therms per month.[1017] She explained that "based upon the proposed revenue increase, a customer using 56 therms per month would essentially receive the same increase to their bill in RY3 whether [BGE's] proposed Customer Charge and volumetric Delivery Price rate design is accepted or whether the full RY3 increase is assigned to the volumetric Delivery Price."[1018]

519. She stated that "79% of the total average gas residential customer bill would be recovered through volumetric rates as opposed to a fixed charge."[1019] So "an increase in the Customer Charge has a minimal impact on the percentage of the total average residential customer bill that would be recovered through volumetric as opposed to fixed

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[1016] Table 2 adapted from Table 15 in Fiery Direct at 33.
[1017] Fiery Direct at 34.
[1018] *Id.*
[1019] *Id.*

charges."[1020] Ms. Fiery contended, therefore, that "[t]he fixed Customer Charge increases I am proposing, therefore, would not have a meaningful impact on the price signals encouraging energy conservation received by residential customers."[1021] Regarding the overall bill impact in Rate Year 3 of the proposed revenue increase, Ms. Fiery stated that for the average Schedule D customer using 56 therms the change in the monthly bill will be $8.04 and the percentage change in monthly bill will be 10.73 percent.[1022]

520. Ms. Fiery proposed to increase the customer charge from $14.25 to $15.25 for Schedule D customers in Rate Year 3, accounting for $7.9 million of the $63.8 million total proposed revenue increase for this schedule. The remaining revenue increase she proposes to recover through the Delivery Price of $0.7154 per therm, which is an increase from the 2023 effective rate of $0.5898 per therm.[1023] Next, she proposed to increase the customer charge for Schedule C customers from $36.30 to $38.00, accounting for $0.9 million of the $25.3 million total proposed revenue increase for this schedule.[1024] In its Initial Brief, BGE noted that "BGE's current and proposed residential gas Customer Charges are not outliers when compared to other Maryland gas utilities as the residential customer charge for Columbia Gas of Maryland [is] $15.40."[1025]

[1020] *Id*. at 35.
[1021] *Id*.
[1022] *Id*. at 36.
[1023] *Id*. at 37.
[1024] *Id*.
[1025] BGE Initial Brief at 73.

521. For Schedule IS – Interruptible Large Volume Service, Ms. Fiery proposed a Demand Price of $1.1314 per therm in RY3, an increase from $0.8323 per therm.[1026] She also proposes a Delivery Price of $0.0808 per therm in RY3, an increase from $0.0712 per therm.[1027]

522. For Schedule ISS – Interruptible Small Volume Service, Ms. Fiery proposed to increase the customer charge from $363.50 to $375.00 in Rate Year 3. She proposed a Demand Price of $1.2513 per therm in RY3, an increase from $1.0538 per therm. She also proposed a Delivery Price of $0.1405 per therm in Rate Year 3, an increase from $0.1190 per therm.[1028]

Staff

523. Staff witness Hauer disagreed with BGE's proposed customer charge, which she says represents a 7.02 percent increase.[1029] Ms. Hauer argued that a 7.02 percent increase does not follow the principle of gradualism and is substantially higher than the average increase the Commission has approved in previous BGE rate cases and settlement agreements.[1030] In her Direct Testimony, Ms. Hauer presented a table showing the current customer charges, Company-proposed customer charges, approved customer charges, and percent change in customer charges for BGE's previous rate cases and settlement agreements for the past 10 years.[1031]

[1026] Fiery Direct at 38.
[1027] *Id*.
[1028] *Id*.
[1029] Hauer Direct at 17.
[1030] *Id*.
[1031] *Id*.

524. Ms. Hauer proposed instead to increase the residential fixed rate to $14.70, which represents a 3.16 percent increase.[1032] She stated that this proposed increase represents the average percent increase from the three most recent rate cases and settlement agreements. Also, Ms. Hauer argued that the proposed 3.16 percent increase in the residential fixed costs "balances the recovery of fixed costs through fixed charge with the principle of gradualism, while ultimately serving to alleviate intra-class subsidies."[1033]

525. Ms. Hauer also opposed BGE's proposed customer charge increase for its Commercial and Small Interruptible customers. She argued that the magnitude of the proposed increases is too large and not consistent with gradualism.[1034] Instead, Ms. Hauer proposed that for the remaining customer classes a more gradual increase of 1.24 percent to Schedule C and 1.28 percent to Schedule ISS.[1035] She based her proposal on the average increase of BGE's three most recent rate cases and settlement agreements.[1036]

<u>OPC</u>

526. OPC Witness Mierzwa disagreed with BGE's customer charge increase for Schedule D. He argued that the proposed increase is inconsistent with Commission policy and that "BGE's current Schedule D is already significantly higher than applicable Residential monthly customer charge of WGL…"[1037] Mr. Mierzwa estimated that the direct customer-related costs associated with serving a customer under Schedule D is

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[1032] *Id*. at 18.
[1033] *Id*.
[1034] *Id*. at 19-20.
[1035] *Id*. at 20.
[1036] *Id*.
[1037] Mierzwa Direct at 26.

$10.86, which is less than the current monthly charge of $14.75. OPC therefore recommended that the Schedule D monthly customer charge should not be increased.[1038]

Commission Decision

527. In addition to changes in the distribution rates, BGE proposes to increase customer charges in three rate classes – Schedules D, C, and ISS – in Rate Year 3. Staff proposes smaller increases in the same rate classes as BGE beginning in Rate Year 3. OPC proposes no increase in the residential class and makes no recommendation on the other rate classes. The chart below summarizes the proposed customer charge increase in RY3.

Table 11

Proposed Customer Charge Increase in Rate Year 3

Customer Class	Current	BGE Proposal	Staff Proposal	OPC Proposal
D	$14.25	$15.25	$14.70	$14.25
C	$36.30	$38.00	$36.75	--
ISS	$363.50	$375.00	$368.15	--

528. Moreover, as demonstrated in Table 16 of BGE witness Fiery' Direct Testimony, the proposed increase in customer charge "has minimal impact on the percentage of the total average residential customer bill that would be recovered through volumetric as opposed to fixed charges."[1039]

[1038] *Id*. at 27.
[1039] Fiery Direct at 35.

Table 11-1 Summary of Exhibit LFK-1[1040]			
Comparison of Bills for Average Gas Schedule D Customers	**Bill at Current Rates**	**Proposed Bill with increased Customer Charge**	**Proposed Bill without increased Customer Charge**
Total Charges	$74.97	$83.00	$82.99
% of Fixed Total Charges	22%	21%	20%
% of Variable Total Charges	78%	79%	80%

529. The table shows and the Commission finds that there is virtually no difference in a customer's bill with the increase in customer charge for the average residential customer. Therefore it will have no impact on energy conservation or state incentives to reduce energy use.

530. In considering increases to customer charges, the Commission is mindful of public policy goals that are intended to encourage energy conservation and give customers more control over their bills by increasing the volumetric charge. Upon review of BGE's proposed increases in Schedules D, C and ISS, the Commission finds them to be reasonable. This decision strikes a balance between the ratemaking principles of cost causation and gradualism, while continuing to provide an incentive for customers to conserve energy usage and have control over their bills. Accordingly, the Commission directs BGE to set the new customer charges to become effective January 1, 2022 since the Commission is offsetting all changes in rates with the new rider in 2021.

[1040] This table is adapted from Table 16 in BGE witness Fiery's Direct Testimony at 35.

Bill Impact Summary

531. As discussed in the BGE Offset Rider Proposal section below, the Commission has directed a 100 percent offset of revenues in 2021--no charge should be different for 2021 than it is for 2020, except adjusted for the BSA forecast. Therefore, by deferring the rate increase for 2021 only, the Schedule D relative rate of return is 0 percent, and the average residential bill increase is $0.00 in 2021. See chart below.

Resulting Bill Impacts[1041]

Average Residential Bill Impact						
	Electric Customer		**Gas Customer**		**Electric & Gas Customer**	
	$	**%**	**$**	**%**	**$**	**%**
2021	-	0.00%	-	0.00%	-	0.00%
2022	$4.40	9.85%	$4.77	8.96%	$8.24	9.48%
2023	$1.88	3.84%	$0.71	1.16%	$2.07	2.19%

D. Rider 15

532. Staff witness Hauer expressed concerns that BGE's proposed language regarding how any imbalance is allocated may be internally inconsistent and prejudge the allocation method. She made a similar recommendation as Staff witness Thompson with regard to Rider 16 concerning removing the phrase "in proportion to each Schedule's amount of base distribution revenues in the final year of the [MRP]."[1042]

[1041] As noted above in the New BGE Offset Rider section, the Commission reserves the right to determine whether to apply additional offsets in 2022 and 2023.

[1042] Hauer at 32 – 33.

Commission Decision

533. The Commission accepts Staff's proposed tariff language to Rider 15. Specifically, the first sentence in the subsection Calculation of Rate shall be edited to remove the phrase "in proportion to each Schedule's amount of base distribution revenues in the final year of the MRP."[1043] The Commission also directs BGE to update Gas Rider 15 to replace references to "per kilowatt-hour" with "per therm."

VII. Conclusions Regarding the MRP Pilot

534. In Order No. 89226, the Commission found that the record developed in Public Conference 51 supported the use of an MRP as an alternative to traditional ratemaking methods, and determined that a properly constructed MRP could result in just and reasonable rates and yield several benefits over time. Specifically, the Commission found that MRPs could shorten the cost recovery period and provide more predictable revenues for utilities, provide more predictable rates for customers and spread changes in rates over a multi-year period, and decrease administrative burdens on regulators by staggering filings over several years.[1044] The Commission finds that this Order will generally achieve those goals.

535. However, BGE's pilot MRP Application has also produced a number of challenges that the Commission and stakeholders will need to address in this proceeding and in future MRPs. Most importantly, access to information by all parties is vital to an effective and fair MRP. As the Commission stated in its MRP Pilot Order: "In any rate case, stakeholders must have access to the data and methods relied on by a utility to

[1043] Thompson Direct at 42.
[1044] Order No. 89226 at 54.

develop and support its case."[1045] In an MRP, access to information becomes even more vital. Yet, as discussed at length in this proceeding, asymmetries of information impeded the parties' ability to fully evaluate and respond to BGE's proposal.[1046] In future MRPs, utilities will need to find better methods of cost-effectively and securely sharing information to level the field for stakeholders to fairly respond to and critique the evidence presented in support of the utility's case. In this proceeding, the Commission will hold BGE to its commitment to improve sharing of information, including at the initial stages of an MRP.[1047]

536. With regard to forecasting, the Commission stated in the MRP Pilot Order that it would not require the Pilot Utility to use a particular method of forecasting, but it did require that the method be utilized consistently throughout the MRP filing.[1048] The Commission also emphasized that "it is imperative that the utility have strong incentives to develop accurate forecasts."[1049] In this case, although BGE shared data and conclusions about its forecasting in its Application, it did not initially produce a witness on the subject. Eventually, BGE witness Zhang submitted supplemental testimony, but the delay impeded the ability of stakeholders to respond to the information.[1050] Because forecasting is fundamental to a properly structured MRP, understanding the utility's methodology—and not just its conclusions—is equally critical. Therefore, utilities filing MRPs are encouraged going forward to provide comprehensive stochastic forecasting

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[1045] MRP Pilot Order at 17.
[1046] Hr'g Tr. at 728 (Alvarez).
[1047] *Id*. at 460 (Vahos).
[1048] MRP Pilot Order at 21.
[1049] *Id*.
[1050] *See* Staff Reply Brief at 31.

information as part of the utility's direct case. In future MRP filings, utilities should also provide witness testimony regarding discrete forecasting generally and as it relates to capital projects in particular.

537. Regarding capital spending, the Commission held that: "Providing sufficient data on planned capital spending at the filing stage of an MRP is essential to allowing transparency into the utility planning process, which the Commission identified as a key benefit of an MRP."[1051] The MRP Pilot Order required project-level data for the first year of the Pilot's rate effective period, program-level data for each additional year of the MRP, and project-level data for large capital expenditures regardless of the year. In the present case, the parties expressed frustration at the lack of detail provided by BGE regarding a number of projects and programs in its capital spending plan. OPC, for example, complained of proposed capital spending consisting of "placeholders—in other words, dollars for projects that are not defined and do not exist" and multiple instances where "historical budgets were doubled or tripled or more without explanation."[1052] In future MRPs, the Commission encourages utilities to provide robust project-level detail, which is a necessary element of allowing stakeholders and the Commission transparency into the utility's planning process. Utilities should also provide a weighing of the importance of proposed capital projects, rather than a simple wish list untethered from ratepayer impact.

538. Transparency is paramount in an MRP, as discussed throughout this Order. Utilities filing future MRPs should endeavor to maximize transparency in the planning

[1051] MRP Pilot Order at 23.
[1052] OPC Initial Brief at 4.

process, including by harmonizing inconsistent forecasting methodologies. A successful MRP process requires that stakeholders have sufficient information to make informed recommendations and adjustments in their respective direct testimonies, with transparency continuing throughout the discovery and adjudicative stages of the proceeding.

539. With respect to customer benefits, MRPs are designed to make rates more predictable for customers, with rate increases spread gradually over multiple years. In this case, however, the exigency of the unprecedented COVID-19 pandemic led the Commission to approve a pilot MRP that prevents customer bills from increasing for the first year of the MRP, but which will also lead to steeper rate increases in subsequent years. Future MRPs should provide opportunities for smoother transitions in rates from year to year.

540. Going forward, BGE, the stakeholders, and the Commission have an opportunity to continue to improve the MRP process. In this proceeding, BGE will make annual informational filings, which will provide the Commission with an opportunity to make mid-cycle MRP adjustments where warranted. Additionally, there will be a reconciliation process and prudency review at the conclusion of the MRP, where the difference between forecasted and actual amounts will be evaluated, and any amounts owed to customers will be refunded with carrying charges.

IT IS THEREFORE, this 16th day of December, in the year Two Thousand Twenty, by the Public Service Commission of Maryland,

ORDERED (1) That the Application of Baltimore Gas and Electric Company, filed on May 15, 2020 (as supplemented by the Company over the course of this proceeding), seeking a multi-year plan requesting gas and electric rates to be effective January 1, 2021, January 1, 2022, and January 1, 2023, and claiming electric revenue deficiencies of $109.0 million, $156.1 million and $203.8 million in 2021, 2022 and 2023, respectively; and gas revenue deficiencies of $65.9 million, $76.2 million and $109.7 million in 2021, 2022 and 2023, respectively, is hereby denied;

(2) That BGE is hereby authorized to increase its Maryland electric and gas distribution rates by no more than the amounts provided in the chart below:

Electric – Incremental Revenue Requirement	**Authorized**
2021	$59,334,000
2022	$38,696,000
2023	$41,879,000

Gas – Incremental Revenue Requirement	**Authorized**
2021	$53,246,000
2022	$10,769,000
2023	$9,872,000

(3) That BGE is directed to accelerate the return of certain customer monies to ensure that there is no bill impact to customers during 2021, but that it will not use accelerated offsets to prevent a bill increase in 2022, absent further direction from the Commission;

(4) That BGE 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 "BGE Federal Tax Credit;"

(5) That BGE's proposals to put some or all of its STRIDE investments into MRP rates is denied; however, the Commission approves BGE's proposal to place into MRP rates all STRIDE investments through December 31, 2020, subject to review;

(6) That BGE is directed to extend the spending timeframe or budgeted increases of certain work plan budgets from three years to five years to reduce financial impacts on customers, as discussed in the body of this Order;

(7) That BGE is directed to make a filing within 60 days of this Order related to the Company's proposed work plans that either: (i) accepts the reduced revenue requirement as presented in this Order; or (ii) proposes to prioritize the reduced revenue requirement on a revised set of work plans;

(8) That OPC's Request for Stakeholder-Engaged Distribution Planning and Capital Budgeting Process is denied at this time;

(9) That BGE's request that electric vehicle costs be moved into rates is granted, subject to a prudency review that will take place at the conclusion of the three-year MRP rate-effective period;

(10) That the PC44 Electric Vehicle Work Group shall develop and propose for Commission consideration a consensus benefit-cost approach and methodology by December 1, 2021;

(11) That the directive contained in Order No. 88997 to include within any future rate case a benefit-cost analysis on electric vehicle programs is temporarily stayed pending future Commission order;

(12) That BGE is directed to file tariffs in compliance with this Order with the effective dates prescribed herein, subject to acceptance by the Commission; and

(13) That all motions or requests not granted herein are denied.

/s/ Jason M. Stanek

/s/ Michael T. Richard

/s/ Anthony J. O'Donnell

/s/ Odogwu Obi Linton

/s/ Mindy L. Herman

Commissioners

Dissenting and Concurring Statements of Michael T. Richard
BGE Customer Charges

1. I dissent in part from the Commission's Order on BGE's MRP, in regard to increases in Company's residential gas and electric Customer Charges. I am concerned that the Majority's decision to increase these charges may have the unintended consequence of frustrating state environmental and renewable energy goals and these additional charges may also have a disparate impact on renters and low-income customers. Numerous studies, by various authoritative sources, have all raised concerns about the fairness and adverse impacts of fixed customer charges.[1] Rather than again increasing customer charges, as this Order does, I would vote to freeze customer charges at current levels and conduct a Statewide Maryland-specific study to determine how rate design can cost-effectively contribute to the State's environmental, energy efficiency and renewable energy goals.

2. A Maryland-focused study would inform the Commission on both the positive and negative outcomes of rate-design decisions when setting utility rates. It's important that the Commission fully understand the connection between setting utility rates and cost-effectively achieving legislatively mandated goals. Achieving energy efficiency, carbon reduction and other policy objectives require us to properly account for rate-design elements that may work to undermine these initiatives.

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[1] *See e.g.*, Brendon Baatz, *Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency,* American Council for an Energy-Efficient Economy (March 2017); Jim Lazar, *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs,* The Regulatory Assistance Project (2014); Celia Kuperszmid Lehrman with Shannon Baker-Branstetter, *The fees That Raise Your Electric Bill Even When You Use Less Energy,* Consumer Reports (Mar. 7, 2016); Caroline Golin with The Greenlink Group, *A Troubling Trend in Rate Design: Proposed Alternatives to Harmful Fixed Charges,* The Southern Environmental Law Center (Dec. 2015); and Melissa Whited, Jim Woolf and Joseph Daniel, *Caught in a Fix: The Problem with Fixed Charges for Electricity*--Prepared for Consumers Union--by Synapse Energy Economics, Inc. (Feb. 9, 2016).

3. In this case, a study could determine what specific impacts result from increasing a utility customer's fixed charge and thereby identify how such impacts reduce a customer's ability to control their bill—effectively increasing the time it takes to "pay off" energy reducing measures. Conversely, fixed charges reduce volumetric charges, making the use of electricity less expensive on the margin—thus diminishing the incentive to reduce energy consumption.

4. Equally important, the Commission should also assess the disparate and potentially unfair impacts residential fixed charges have on Maryland low-income customers—and customers who also may be low-volume consumers—of electric and gas service, such as apartment dwellers and those living in high-density urban centers. These are concerns raised by a number of consumer organizations and low-income advocates, including in several of the reports cited here. Maryland has a suite of programs intended to help financially-distressed citizens maintain essential utility services, and calls to address energy burdens on low-income households is of growing importance to policymakers. The Commission should be careful to not exacerbate low-income energy burdens without fully exploring rate-design impacts on different socio-economic groups and customer usage profiles.

5. In brief, there are many State policy objectives that may be adversely impacted by fixed-utility charges, and I believe it would be wise for the Commission to suspend any further increases while taking the time to assess whether higher customer charges are consistent with Maryland policies.

6. Over the coming years it will become more challenging to cost effectively meet EmPOWER energy reduction targets, achieve greenhouse gas reductions, and

Maryland's increasing renewable goals. Rate design may be an area ripe for the development of new energy efficiency measures and to otherwise incent beneficial customer behaviors. It is also important to consider how customer responses to rate-design changes interact with efficiency goals, adoption of renewables and other utility programs. Maryland decoupling policies already provide utilities with stable revenues. If a utility also chooses to increase residential fixed charges, through higher customer charges, then some trade-off for any negative impacts on State policies should be reconciled with the utility's legislative mandates.

7. For these reasons I partially dissent in this Order and would not increase the residential customer charge without a full understanding of the impacts of fixed charges on important State policies, and of the disparate impacts on low-income and low-volume energy users.

STRIDE

8. I support the decision in this Order to place all STRIDE investments through December 31, 2020 into MRP rates, thus allowing the surcharge cap to zero out and be reset. This would largely mitigate the financial impacts of the Commission's finding that placing STRIDE projects into base rates somehow circumvents the intent of the General Assembly. However, I agree with the Company that the General Assembly enacted the STRIDE statute to prioritize gas safety investments at a time when the Commission primarily set utility rates based on historic test years.

9. With the use of a forecasted test year, the Company's high-priority projects can now be made part of the BGE's capital investment plan, and no longer require an accelerated recovery mechanism. I further agree that there is nothing in the STRIDE

statute that restricts the Commission's authority in any way from moving STRIDE projects – which have already been subjected to rigorous review – into the Company's capital investment plan, nor can I imagine that the General Assembly intended that these high-priority safety projects would be placed in a worse position than any other capital investment program that the Commission would otherwise be approving in an MRP.

10. For the following reasons – and only these – I concur with this part of the Commission's decision: (1) this case is a pilot MRP and does not set precedent; (2) adverse financial impacts on customers are mitigated; and (3) the Company is allowed to recover most of its STRIDE project expenses.

/s/ Michael T. Richard
Commissioner

Concurring Statement of
Commissioners Mindy L. Herman and Anthony J. O'Donnell

1. As discussed below, we do not find that BGE, in this proceeding, provided sufficient detail and explanation of the prudency of the costs associated with the gas meter relocation and protection program as directed by the Commission in Order No. 88975 in Case No. 9484.[1] Rather than allowing the cost of this program in its entirety, we would have disallowed a portion of those costs based on the lack of evidence provided by the Company.

2. In Case No. 9484, the Commission allowed recovery of the gas meter relocation and protection program costs requested by BGE in that case; however, the Commission specifically stated that future costs were at risk – pending the prudency review in a subsequent rate case:[2]

> [T]he Commission grants BGE's requests to recover the Gas Meter Relocation and Protection Program expenses included in the instant case. However, BGE is directed to create a regulatory asset for the remaining costs of the Gas Meter Relocation and Protection Program and *when that program is complete and BGE seeks to move those costs into rates, the Company shall demonstrate that such costs were prudently incurred*.

In our view, BGE failed to demonstrate—in this proceeding—that its gas meter relocation and protection costs were prudent.

3. When questioned about the evidence the Commission needs to make that determination, BGE witness Olivier stated that the entirety of the evidence regarding

[1] In some instances, in order to minimize the risk of vehicular strikes, gas meters are relocated. In other instances, where feasible, bollards are installed in order to protect the meter when the meter cannot be relocated.
[2] Order No 88975 at 45 (emphasis added).

prudency was contained in her rebuttal testimony.[3] However, that testimony merely states conclusions – that the program is a safety program that the Commission Engineering Division agrees is appropriate, and that the Commission previously allowed recovery of all program costs incurred to date in Case No. 9484.[4] Ms. Olivier elaborated that the program was prudent because it was done efficiently and under budget, but admitted that there were no exhibits or testimony supporting the costs or the efficiency of those costs.[5]

4. As discussed above, in Order No. 88975, the Commission specifically did not approve meter relocation program costs beyond the costs allowed in Case No. 9484, and thus BGE's reliance on Order No. 88975 to demonstrate prudence in this proceeding is misplaced. Nor did BGE sufficiently demonstrate the prudency of continuing the program, either on cross examination or in its brief.

5. Based on the lack of record evidence to support a finding that the additional meter relocation program costs were prudently incurred, we cannot make a prudence determination, or determine the level of disallowance that is warranted, if any.

6. While some, or perhaps most, of the costs, and most of the meter relocation and bollard protection efforts were appropriate, BGE did not address an open conflict in the Company's positions. If the meter relocation program is mandatory in order for BGE to be in compliance with Pipeline and Hazardous Material Safety Administration ("PHMSA") regulations, as Staff asserted in Case No. 9484, then BGE should have demonstrated why it had not already relocated the meters as part of the

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[3] H'rg Tr. at 221-224, referring to BGE Ex. 11 (Olivier Rebuttal) at 2.
[4] *See*, BGE Ex. 11 (Olivier Rebuttal) at 2, lines 12-15.
[5] Hr'g Tr. at 224-25.

ordinary course of its operations. If that were the case, then BGE should have shown the extent to which its meter relocations and bollard installations were prudent, in order to comply with federal regulations. Alternatively, if BGE always was in compliance with the PHMSA regulations as it contends, then the Company should have explained why the relocation of meters and relocation of bollards under a program that was already compliant with federal regulations was still nonetheless prudent. Had BGE established that these costs were prudently incurred, the Company would have been warranted in requesting cost recovery from customers.

7. Ultimately, BGE bears the burden of proof in the case, and based on the above, we do not find that BGE has met the burden for full recovery of the meter relocation program costs at issue in this proceeding.

8. For this reason, we concur in part and dissent in part on the recovery of costs associated with the meter relocation and protection program. In the absence of demonstrating prudency with respect to this program, and being unable to determine the appropriate level of disallowance, we would continue the costs of this program in a regulatory asset account until evidence of prudency can be established.

9. Any return on the regulatory asset, however, should be adjusted to account for the timing gap between this case and when – in the future – prudency of the program costs are firmly established.

/s/ Anthony J. O'Donnell

/s/ Mindy L. Herman
Commissioners

Case No. 9645
Baltimore Gas and Electric Company (Electric)
Multi Year Rate Plan 2021, 2022 and 2023

Development of Awarded Revenue Requirement
($ Thousands)

	2021	2022	2023
Adjusted Rate Base	$3,888,159	$4,121,072	$4,315,215
Rate of Return	6.75%	6.75%	6.75%
Required Operating Income	$ 262,451	$ 278,172	$ 291,277
Adjusted Operating Incomce	$ 220,551	$ 208,946	$ 192,477
Operating Income Deficiency	$ 41,900	$ 69,226	$ 98,800
Conversion Factor	1.41608	1.41608	1.41608
Revenue Requirement	$ 59,333	$ 98,030	$ 139,909
Rate Base			
Per Book Unadjusted Rate Base	$4,097,791	$4,341,094	$4,549,313
Uncontested Adjustments	(12,660)	(4,731)	(2,502)
Total Before Contested Adjustments	$4,085,131	$4,336,363	$4,546,811
Contested Adjustments:			
COVID-19 Regulatory Asset Amortization	$ 2,363	$ 1,838	$ 1,313
Remove CWIP & AFUDC	(174,222)	(149,581)	(132,844)
Adjust Capital Additions	(16,757)	(47,577)	(73,440)
Deny Suspension of Smart Grid	(8,355)	(16,580)	(16,450)
Deny Extension of Smart Grid		(3,391)	(10,174)
Contested Adjustments	$ (196,971)	$ (215,291)	$ (231,595)
Total Rate Base	$3,888,160	$4,121,072	$4,315,216

Operating Income			
Per Book Unadjusted Operating Income	$ 212,884	$ 198,966	$ 180,950
Uncontested Adjustments	33,650	18,585	18,512
Adjusted Income Before Contested Adjustments	$ 246,534	$ 217,551	$ 199,462
Contested Adjustments:			
COVID-19 Regulatory Asset Amortization	$ (1,281)	$ (1,281)	$ (1,281)
Interest Synchronization	(1,515)	(1,307)	(2,176)
Remove CWIP & AFUDC	(10,224)	(8,821)	(8,691)
Adjust Contingencies	770	453	136
Adjust Depreciation Expense	8,137	10,697	12,811
Deny Suspension of Smart Grid	(22,449)	266	65
Deny Extension of Smart Grid		(9,859)	(9,859)
Adjust Property Tax Expense	578	1,245	2,008
Total Contested Adjustments	$ (25,984)	$ (8,607)	$ (6,987)
Net Operating Income	$ 220,550	$ 208,944	$ 192,475

Case No. 9645
Baltimore Gas and Electric Company (Gas)
Multi Year Rate Plan 2021, 2022 and 2023

Development of Awarded Revenue Requirement
($ Thousands)

	2021	2022	2023
Adjusted Rate Base	$2,267,231	$2,357,799	$2,443,182
Rate of Return	6.83%	6.83%	6.83%
Required Operating Income	$ 154,852	$ 161,038	$ 166,869
Adjusted Operating Incomce	$ 117,332	$ 115,930	$ 114,804
Operating Income Deficiency	$ 37,520	$ 45,108	$ 52,065
Conversion Factor	1.41913	1.41913	1.41913
Revenue Requirement	$ 53,246	$ 64,014	$ 73,887
Rate Base			
Per Book Unadjusted Rate Base	$2,404,168	$2,645,166	$2,878,127
Uncontested Adjustments	(11,122)	(9,162)	(7,480)
Total Before Contested Adjustments	$2,393,046	$2,636,004	$2,870,647
Contested Adjustments:			
Remove CWIP	$ (64,032)	$ (87,340)	$ (105,093)
Amortization of COVID-19 Costs	1,325	1,030	473
Remove Plant Net - Non-STRIDE	(416)	(5,713)	(17,778)
Remove Plant Net - STRIDE	(59,942)	(179,529)	(296,050)
Deny Suspension of Smart Grid	(2,750)	(5,444)	(5,389)
Deny Extension of Smart Grid		(1,209)	(3,628)
Contested Adjustments	$ (125,815)	$ (278,205)	$ (427,465)
Total Rate Base	$2,267,231	$2,357,799	$2,443,182

<u>Operating Income</u>			
Per Book Unadjusted Operating Income	$ 122,209	$ 132,755	$ 124,773
Uncontested Adjustments	9,273	5,240	5,447
Adjusted Income Before Contested Adjustments	$ 131,482	$ 137,995	$ 130,220
Contested Adjustments:			
Remove CWIP	$ (4,333)	$ (7,105)	$ (5,764)
Amortization of COVID-19 Costs	(526)	(526)	(526)
Adjust Amort of Gas Meter Relocation		(810)	
STRIDE Revenue Impact	(5,285)	(16,348)	(16,489)
Interest Synchronization	(28)	(28)	(663)
Remove Contingencies	389	229	69
Deny Suspension of Smart Grid 2021	(6,511)	146	26
Deny Extension of Smart Grid Amortization		(2,922)	(2,922)
Adjust Depreciation - Plant Additions	36	(298)	638
Adjust Depreciation - STRIDE	1,833	5,006	9,262
Adjust Property Tax Expense	275	591	954
Total Contested Adjustments	$ (14,150)	$ (22,065)	$ (15,415)
Net Operating Income	$ 117,332	$ 115,930	$ 114,805

Appendix B
Staff Comparison Chart

Case No. 9645
Baltimore Gas and Electric Company (Electric)
2021
Revenue Requirement Comparison
(Thousands of Dollars)

			BGE (Rebuttal)				**Staff (Surrebuttal)**				**OPC (Surrebuttal)**				**DOD (Surrebuttal) ***			
Conversion			1.41608				1.41608				1.41608				1.41608			
ROR			7.09%	Rate Base	Operating Income	Revenue Requirement	6.70%	Rate Base	Operating Income	Revenue Requirement	6.39%	Rate Base	Operating Income	Revenue Requirement	6.68%	Rate Base	Operating Income	Revenue Requirement
		Unadjusted																
		Plant		7,861,965														
		Accumulated Depreciation and Amortization		(2,850,917)														
		Materials and Supplies		26,935														
		Cash Working Capital		32,100														
		Accumulated Deferred Income Taxes		(693,685)														
		Prepaid Pension/OPEB Liab.		50,753														
		Customer Advances & Deposits		(89,984)														
		Regulatory Assets & Liabilities		(239,376)														
		Total Unadjusted		4,097,791	212,884	$ 109,958		4,097,791	212,884	$ 87,327		4,097,791	212,884	$ 69,524		4,097,791	212,884	$ 86,004
		Uncontested Adjustments		(12,660)	33,650	$ (48,922)		(12,660)	33,650	$ (48,852)		(12,660)	33,650	$ (48,797)		(12,660)	33,650	$ (48,848)
OIA	RBA	**Contested / Adjusted Adjustments**																
38	14	Accelerated Tax Benefits		22,604	45,208	$ (61,749)		14,731	29,463	$ (40,324)		22,604	45,208	$ (61,972)		7,598	15,194	$ (20,797)
41	17	COVID-19 Regulatory Asset Amortization		6,403		$ 643		2,363	(1,281)	$ 2,038		6,403		$ 580		6,403	-	$ 605
43		Interest Synchronization			(50)	$ 71			(1,316)	$ 1,864			(1,393)	$ 1,973			(50)	$ 71
		Remove CWIP & AFUDC				$ -		(174,222)	(10,224)	$ (2,052)				$ -				$ -
		Adjust Capital Additions				$ -				$ -		(230,122)		$ (20,834)				$ -
		Remove Prepaid Pension/OPEB Liab.				$ -				$ -				$ -		(123,100)		$ (11,640)
		Revenue Excess Regulatory Liability				$ -				$ -		(34,753)		$ (3,146)				$ -
		Adjust Operating Revenues - Customers				$ -				$ -			3,967	$ (5,618)				$ -
		Adjust Non-Labor O&M Inflation				$ -				$ -			(520)	$ 737			870	$ (1,232)
		Adjust Minor Storm Damage				$ -				$ -			4,554	$ (6,448)				$ -
		Adjust Contingencies				$ -				$ -			770	$ (1,090)				$ -
		Adjust Depreciation Expense				$ -				$ -			13,853	$ (19,617)				$ -
		Adjust Property Tax Expense				$ -				$ -			3,502	$ (4,960)				$ -
		Total		$ 4,114,137	$ 291,692	$ -		$ 3,928,002	$ 263,176	$ -		$ 3,849,263	$ 316,475	$ (99,668)		$ 3,976,032	$ 262,548	$ 4,163

Capital Structure	BGE Ratio	BGE Cost	BGE Wt'd Return	Staff Ratio	Staff Cost	Staff Wt'd Return	OPC Ratio	OPC Cost	OPC Wt'd Return	DOD Ratio	DOD Cost	DOD Wt'd Return
Long-Term Debt	48.00%	3.83%	1.84%	48.00%	3.78%	1.81%	48.00%	3.84%	1.84%	48.00%	3.89%	1.87%
Common Equity	52.00%	10.10%	5.25%	52.00%	9.40%	4.89%	52.00%	8.75%	4.55%	52.00%	9.25%	4.81%
Rate of Return	100.00%		7.09%	100.00%		6.70%	100.00%		6.39%	100.00%		6.68%

*Accelerated Tax Benefits adjustment amounts have not been updated to reflect BGE's rebuttal

Case No. 9645
Baltimore Gas and Electric Company (Electric)
2022
Revenue Requirement Comparison
(Thousands of Dollars)

			BGE (Rebuttal)				Staff (Surrebuttal)				OPC (Surrebuttal)				DOD (Surrebuttal) *			
Conversion			1.41608				1.41608				1.41608				1.41608			
ROR			7.10%	Rate Base	Operating Income	Revenue Requirement	6.71%	Rate Base	Operating Income	Revenue Requirement	6.39%	Rate Base	Operating Income	Revenue Requirement	6.68%	Rate Base	Operating Income	Revenue Requirement
		Unadjusted																
		Plant		8,281,844														
		Accumulated Depreciation and Amortization		(3,016,471)														
		Materials and Supplies		27,631														
		Cash Working Capital		34,457														
		Accumulated Deferred Income Taxes		(728,360)														
		Prepaid Pension/OPEB Liab.		52,965														
		Customer Advances & Deposits		(92,854)														
		Regulatory Assets & Liabilities		(218,117)														
		Total Unadjusted		4,341,094	198,966	$ 154,709		4,341,094	198,966	$ 130,734		4,341,094	198,966	$ 111,260		4,341,094	198,966	$ 128,718
		Uncontested Adjustments		(4,731)	18,585	$ (26,794)		(4,731)	18,585	$ (26,767)		(4,731)	18,585	$ (26,746)		(4,731)	18,585	$ (26,765)
OIA	RBA	**Contested / Adjusted Adjustments**																
38	14	Accelerated Tax Benefits		93,545	96,673	$ (127,492)		68,830	78,735	$ (104,955)		93,545	96,673	$ (128,428)		46,315	62,238	$ (83,755)
41	17	COVID-19 Regulatory Asset Amortization		6,403		$ 644		1,838	(1,281)	$ 1,989		6,403	-	$ 580		6,403	-	$ 605
43		Interest Synchronization			752	$ (1,065)			(510)	$ 722			(1,472)	$ 2,084			752	$ (1,065)
		Remove CWIP & AFUDC				$ -		(149,581)	(8,821)	$ (1,722)				$ -				$ -
		Adjust Capital Additions				$ -				$ -		(337,944)		$ (30,595)				$ -
		Remove Prepaid Pension/OPEB Liab.				$ -				$ -				$ -		(123,100)		$ (11,640)
		Revenue Excess Regulatory Liability				$ -				$ -		(100,460)		$ (9,095)				$ -
		Adjust Operating Revenues - Customers				$ -				$ -			4,628	$ (6,554)				$ -
		Adjust Non-Labor O&M Inflation				$ -				$ -			(533)	$ 755			870	$ (1,232)
		Adjust Minor Storm Damage				$ -				$ -			4,971	$ (7,040)				$ -
		Adjust Contingencies				$ -				$ -			453	$ (641)				$ -
		Adjust Depreciation Expense				$ -				$ -			18,569	$ (26,296)				$ -
		Adjust Property Tax Expense				$ -				$ -			6,616	$ (9,368)				$ -
		Total		$ 4,436,310	$ 314,978	$ -		$ 4,257,450	$ 285,675	$ -		$ 3,997,907	$ 347,459	$ (130,087)		$ 4,265,981	$ 281,411	$ 4,867

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	48.00%	3.85%	1.85%	48.00%	3.79%	1.82%	48.00%	3.84%	1.84%	48.00%	3.89%	1.87%
Common Equity	52.00%	10.10%	5.25%	52.00%	9.40%	4.89%	52.00%	8.75%	4.55%	52.00%	9.25%	4.81%
Rate of Return	100.00%		7.10%	100.00%		6.71%	100.00%		6.39%	100.00%		6.68%

*Accelerated Tax Benefits adjustment amounts have not been updated to reflect BGE's rebuttal

Case No. 9645
Baltimore Gas and Electric Company (Electric)
2023
Revenue Requirement Comparison
(Thousands of Dollars)

			BGE (Rebuttal)				Staff (Surrebuttal)				OPC (Surrebuttal)				DOD (Surrebuttal) *			
Conversion			1.41608				1.41608				1.41608				1.41608			
ROR			7.09%	Rate Base	Operating Income	Revenue Requirement	6.70%	Rate Base	Operating Income	Revenue Requirement	6.39%	Rate Base	Operating Income	Revenue Requirement	6.68%	Rate Base	Operating Income	Revenue Requirement
		Unadjusted																
		Plant		8,687,504														
		Accumulated Depreciation and Amortization		(3,199,513)														
		Materials and Supplies		28,344														
		Cash Working Capital		36,809														
		Accumulated Deferred Income Taxes		(760,018)														
		Prepaid Pension/OPEB Liab.		52,758														
		Customer Advances & Deposits		(95,695)														
		Regulatory Assets & Liabilities		(200,876)														
		Total Unadjusted		4,549,313	180,950	$ 200,512		4,549,313	180,950	$ 175,387		4,549,313	180,950	$ 155,622		4,549,313	180,950	$ 173,918
		Uncontested Adjustments		(2,502)	18,512	$ (26,466)		(2,502)	18,512	$ (26,452)		(2,502)	18,512	$ (26,441)		(2,502)	18,512	$ (26,451)
OIA	RBA	**Contested / Adjusted Adjustments**																
38	14	Accelerated Tax Benefits		161,433	39,103	$ (39,165)		144,591	72,787	$ (89,354)		161,433	39,103	$ (40,758)		129,209	103,551	$ (134,419)
41	17	COVID-19 Regulatory Asset Amortization		5,762	(1,281)	$ 2,393		1,313	(1,281)	$ 1,939		5,762	(1,281)	$ 2,336		5,762	(1,281)	$ 2,359
43		Interest Synchronization			200	$ (283)			(957)	$ 1,355			(2,724)	$ 3,857			200	$ (283)
		Remove CWIP & AFUDC				$ -		(132,844)	(8,691)	$ (297)				$ -				$ -
		Adjust Capital Additions				$ -				$ -		(442,146)		$ (40,029)				$ -
		Remove Prepaid Pension/OPEB Liab.				$ -				$ -				$ -		(120,800)		$ (11,422)
		Revenue Excess Regulatory Liability				$ -				$ -		(134,369)		$ (12,165)				$ -
		Adjust Operating Revenues - Customers				$ -				$ -			4,817	$ (6,822)				$ -
		Adjust Non-Labor O&M Inflation				$ -				$ -			732	$ (1,037)			870	$ (1,232)
		Adjust Minor Storm Damage				$ -				$ -			5,226	$ (7,400)				$ -
		Adjust Contingencies				$ -				$ -			136	$ (192)				$ -
		Adjust Depreciation Expense				$ -				$ -			23,067	$ (32,665)				$ -
		Adjust Property Tax Expense				$ -				$ -			10,015	$ (14,183)				$ -
		Total		$ 4,714,006	$ 237,485	$ 136,989		$ 4,559,870	$ 261,321	$ 62,577		$ 4,137,491	$ 278,555	$ (19,876)		$ 4,560,982	$ 302,802	$ 2,470

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	48.00%	3.84%	1.84%	48.00%	3.78%	1.81%	48.00%	3.84%	1.84%	48.00%	3.89%	1.87%
Common Equity	52.00%	10.10%	5.25%	52.00%	9.40%	4.89%	52.00%	8.75%	4.55%	52.00%	9.25%	4.81%
Rate of Return	100.00%		7.09%	100.00%		6.70%	100.00%		6.39%	100.00%		6.68%

*Accelerated Tax Benefits adjustment amounts have not been updated to reflect BGE's rebuttal

Case No. 9645
Baltimore Gas and Electric Company
For Rates to be Assessed in 2021- Yr 1 of MYP
Gas Revenue Requirement Comparison
(Thousands of Dollars)

	BGE			STAFF			OPC			DOD*		
	7.09%	1.41913		6.80%	1.41913		6.39%	1.41913		6.68%	1.41913	
	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement
Unadjusted Results	2,404,168	122,209	68,468	2,404,168	122,209	58,574	2,404,168	122,209	44,694	2,404,168	122,209	54,384
Uncontested Adjustments	(11,122)	9,273	(14,279)	(11,122)	9,273	(14,233)	(11,122)	9,273	(14,169)	(11,122)	10,181	(15,567)
Total Results before Contested Adjustments	2,393,046	131,482	54,189	2,393,046	131,482	44,341	2,393,046	131,482	30,525	2,393,046	132,390	38,817
Contested Adjustments												
Remove CWIP				(64,032)	(4,333)	(30)						
Adjust Mitigation Measures	19,420	38,841	(53,166)	15,608	31,218	(42,796)	19,420	38,841	(53,358)	10,968	21,936	(30,026)
Amortization of COVID-19 Costs	2,632	-	265	1,325	(526)	874	2,632		239			
Adjust Amort of Gas Meter Relocation			-			-		0	-			
STRIDE Impact					145	(206)		(5,285)	7,500			
Interest Synchronization		908	(1,289)		1,539	(2,184)		(260)	369			
Remove Plant Net							(213,397)		(19,361)			
Reg Liability- Excess Revenues							(16,975)		(1,540)			
Additional Revenue from Gas Connections								768	(1,089)			
Non-labor O&M Inflation								(263)	373		435	(617)
Remove Prepaid Pension										(64,700)		(6,510)
Remove Contingencies								389	(552)			
Adjust Depreciation								6,534	(9,273)			
Adjust Property Tax Expense								1,337	(1,897)			
Total Contested Adjustments	22,052	39,749	(54,190)	(47,099)	28,043	(44,342)	(208,320)	42,061	(78,590)	(53,732)	22,371	(37,153)
Total Revenue Requirement	2,415,098	171,231	(1)	2,345,947	159,525	(1)	2,184,725	173,543	(48,065)	2,339,314	154,761	1,664

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	48.00%	3.83%	1.84%	48.00%	3.78%	1.81%	48.00%	3.84%	1.84%	48.00%	3.89%	1.87%
Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity	52.00%	10.10%	5.25%	52.00%	9.60%	4.99%	52.00%	8.75%	4.55%	52.00%	9.25%	4.81%
Rate of Return	100.00%		7.09%	100.00%		6.80%	100.00%		6.3932%	100.00%		6.68%

*Mitigation Adjustment amounts have not been updated to reflect BGE's rebuttal

Case No. 9645
Baltimore Gas and Electric Company
For Rates to be Assessed in 2022- Yr 2 of MYP
Gas Revenue Requirement Comparison
(Thousands of Dollars)

	BGE			STAFF			OPC			DOD*		
	7.10%	1.41914		6.81%	1.41914		6.39%	1.41914		6.68%	1.41914	
	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement
Unadjusted Results	2,645,166	132,755	78,126	2,645,166	132,755	67,240	2,645,166	132,755	51,594	2,404,168	132,755	39,418
Uncontested Adjustments	(9,162)	5,240	(8,359)	(9,162)	5,240	(8,322)	(9,162)	5,240	(8,268)	(9,162)	5,240	(8,359)
Total Results before Adjustments	2,636,004	137,995	69,767	2,636,004	137,995	58,918	2,636,004	137,995	43,326	2,636,004	137,995	31,059
Contested Adjustments:												
Remove CWIP				(87,340)	(7,105)	1,642						
Adjust Mitigation Measures	65,273	52,864	(68,444)	54,049	45,662	(59,577)	65,273	52,864	(69,099)	38,419	32,963	(42,908)
Amortization of COVID-19 Costs	2,632		265	1,030	(526)	846	2,632		239			
Adjust Amort of Gas Meter Relocation		(810)	1,150		(405)	575						
STRIDE Impact					652	(925)		(16,348)	23,200			
Interest Synchronization		1,929	(2,738)		1,042	(1,479)		(167)	237			
Remove Plant Net							(358,948)		(32,567)			
Reg Liability- Excess Revenues							(54,351)		(4,931)			
AdditionaL Revenue from Gas Connections								1,003	(1,423)			
Non-labor O&M Inflation								(269)	382		435	(617)
Remove Prepaid Pension										(64,600)		(6,509)
Remove Contingencies								229	(325)			
Adjust Depreciation								10,638	(15,097)			
Adjust Property Tax Expense								2,678	(3,801)			
Total Contested Adjustments	67,905	53,983	(69,767)	(32,261)	39,320	(58,918)	(345,394)	50,628	(103,185)	(26,181)	33,398	(49,772)
Total Revenue Requirement	2,703,909	191,978	(1)	2,603,743	177,315	-	2,290,610	188,623	(59,859)	2,609,823	171,393	(18,713)

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	48.00%	3.83%	1.84%	48.00%	3.79%	1.82%	48.00%	3.84%	1.84%	48.00%	3.89%	1.87%
Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity	52.00%	10.10%	5.25%	52.00%	9.60%	4.99%	52.00%	8.75%	4.55%	52.00%	9.25%	4.81%
Rate of Return	100.00%		7.09%	100.00%		6.81%	100.00%		6.39%	100.00%		6.68%

*Mitigation Adjustment amounts have not been updated to reflect BGE's rebuttal

Case No. 9645
Baltimore Gas and Electric Company
For Rates to be Assessed in 2023- Yr 3 of MYP
Gas Revenue Requirement Comparison
(Thousands of Dollars)

	BGE			STAFF			OPC			DOD*		
	7.09%	1.41914		6.80%	1.41914		6.39%	1.41914		6.68%	1.41914	
	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement	Rate Base	Operating Income	Revenue Requirement
Unadjusted Results	2,878,127	124,773	112,518	2,878,127	124,773	100,673	2,878,127	124,773	84,058	2,404,168	124,773	50,746
Uncontested Adjustments	(7,480)	5,447	(8,483)	(7,480)	5,447	(8,452)	(7,480)	5,447	(8,409)	466,479	5,447	39,206
Total Results before Adjustments	2,870,647	130,220	104,035	2,870,647	130,220	104,035	2,870,647	130,220	75,649	2,870,647	130,220	104,035
Contested Adjustments:												
Remove CWIP				(105,093)	(5,764)	(1,962)						
Adjust Mitigation Measures	99,026	14,642	(10,815)	91,613	29,467	(32,977)	99,026	14,642	(11,795)	80,624	51,447	(64,898)
Amortization of COVID-19 Costs	2,369	(526)	985	473	(526)	792	2,369	(526)	961			
Adjust Amort of Gas Meter Relocation		-	-		(405)	575			-			
STRIDE Impact					12,322	(17,487)		(16,489)	23,400			
Interest Synchronization		2,217	(3,146)		3,619	(5,136)		(752)	1,067			
Remove Plant Net							(513,221)		(46,564)			
Reg Liability- Excess Revenues							(72,143)		(6,545)			
AdditionaL Revenue from Gas Connections								1,238	(1,757)			
Non-labor O&M Inflation								370	(525)		435	(617)
Remove Prepaid Pension										(63,400)		(6,379)
Remove Contingencies								69	(97)			
Adjust Depreciation								16,211	(23,006)			
Adjust Property Tax Expense								4,030	(5,719)			
Total Contested Adjustments	101,395	16,333	(12,977)	(13,007)	38,713	(56,195)	(483,969)	18,792	(70,579)	17,224	51,882	(72,065)
`												
Total Revenue Requirement	2,972,042	146,553	91,059	2,857,640	168,933	36,027	2,386,678	149,012	5,070	2,887,871	182,102	31,970

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	48.00%	3.83%	1.84%	48.00%	3.78%	1.81%	48.00%	3.84%	1.84%	48.00%	3.89%	1.87%
Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity	52.00%	10.10%	5.25%	52.00%	9.60%	4.99%	52.00%	8.75%	4.55%	52.00%	9.25%	4.81%
Rate of Return	100.00%		7.09%	100.00%		6.80%	100.00%		6.39%	100.00%		6.68%

*Mitigation Adjustment amounts have not been updated to reflect BGE's rebuttal