(Maillog No. 306673)

ORDER NO. 90948

Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan	* * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9692

ORDER ON APPLICATION FOR A MULTI-YEAR RATE PLAN

Before: Frederick H. Hoover, Jr., Chair
Michael T. Richard, Commissioner
Anthony J. O'Donnell, Commissioner
Kumar P. Barve, Commissioner
Bonnie A. Suchman, Commissioner

Issued: December 14, 2023

APPEARANCES

David E. Ralph, Beverly A. Sikora, Daniel W. Hurson, Brent Bolea, and Joel Michel for Baltimore Gas and Electric Company.

David S. Lapp, William F. Fields, Juliana Bell, Gary L. Alexander, Mark Szybist, Michael Sammartino, Mollie S. Woods, and Ryan Hsu for the Maryland Office of People's Counsel.

Annette B. Garofalo, Katherine Moriarty, Peter Woolson, and Michael A. Dean for the Maryland Public Service Commission Staff.

Brian R. Greene and Eric J. Wallace for Interstate Gas Supply, Inc., d/b/a IGS Energy; WGL Energy Services, Inc.; NRG Energy, Inc.; and Vistra Corp (Supplier Coalition).

Barry A. Naum, Steven W. Lee, and Don C.A. Parker for Walmart.

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

Lisa Brennan and Jim Ogorzalek for Montgomery County, Maryland.

James McGee for Prince George's County, Maryland

Nicholas J. Enoch for IBEW Local 410

David Shapiro, Joyce Lombardi, Michele Honick, Sondra S. McLemore, and Steven M. Talson for Maryland Energy Administration

Matthew Graham and Robert A. Weishaar, Jr. for National Railroad Passenger Corporation (Amtrak)

Arlus J. Stephens, for Philadelphia-Baltimore-Washington Laborer's District Council

Susan S. Miller for the Sierra Club

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INTRODUCTION AND EXECUTIVE SUMMARY

On February 17, 2023, Baltimore Gas and Electric ("BGE") filed an Application with the Commission seeking approval of distribution rates under a multi-rear rate plan ("MYP")[1]. That Application requested gas and electric rates to be effective January 1, 2024, January 1, 2025, and January 1, 2026.

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 MYP, with offsets as described in this order, as provided in the chart below. Originally BGE requested an increase of $602 million through 2026, the Commission authorizes BGE to increase electric and gas rates by $408 million through 2026.

Table 1

Incremental Impact to Ratepayers by Year	Electric	Gas	Total
2024	$ 92,845	$ 147,462	$ 240,307
2025	$ 60,949	$ 40,681	$ 101,630
2026	$ 25,291	$ 40,555	$ 65,846
Total Impact	$ 179,085	$ 228,698	$ 407,783

[1] The Commission has historically used the acronym "MRP" to refer to a multi-year rate plan, including in Order No. 89226, (Order on Alternative Forms of Rate Regulation), Order No. 89482 (Order Establishing Multi-Year Rate Plan Pilot); and Order No. 89678 (Order on Pilot Application for a Multi-Year Rate Plan). As it did in Case No. 9645, BGE has once again used the term MYP to describe its multi-year rate plan. To avoid confusion, the Commission will use the acronym MYP throughout this Order, except for quotations where parties, or the Commission in previous orders, have used the term MRP. Nevertheless, the acronyms MYP and MRP should be considered interchangeable.

Table 2

Average Residential Bill Impact[2]						
	Electric		Gas		Electric and Gas	
	$	**%**	**$**	**%**	**$**	**%**
2024	$ 4.08	3.01%	$ 10.43	11.54%	$ 14.51	6.42%
2025	$ 1.22	0.87%	$ 2.96	2.94%	$ 4.18	1.74%
2026	$ 0.34	0.24%	$ 2.80	2.70%	$ 3.14	1.29%

In order to cushion the rate increases in year 1, the Commission is accelerating the return of certain customer monies held by BGE to reduce the bill impact to customers during 2024. This is reflected in the approved rate design and the incremental total residential bill impact above. The Commission in approving these overall budgets is not making a prudency finding nor a carte blanche authorization to spend all of these funds.[3] BGE is expected to control costs and minimize impacts to ratepayers while providing safe and reliable service. The Commission expects strong scrutiny from parties when these costs are reviewed for prudency in the future, especially when cost variances are high.

[2] The Bill Impacts presented are inclusive of current energy rates and applicable gas charges.

[3] In approving expenditures for any particular work plan or project for the MYP 2 period, the Commission is not making an advanced determination of prudency. To the contrary, prudency issues such as whether particular projects will ultimately benefit ratepayers, whether actual project costs were excessive, and whether the programs were executed effectively and efficiently will become ripe for prudency review during the reconciliation process. *See* Order No. 89678 at 96, stating "the Commission is not preapproving any particular work plan or project for purposes of prudency in this Order."

BACKGROUND

The Application was submitted by BGE under terms of the MRP Pilot Order.[4] The Application was supported by the filing requirements[5] approved by the Commission in the MRP Pilot Order and the Direct Testimonies and Exhibits of BGE witnesses.

The Commission docketed BGE's Application as Case No. 9692 and issued Order No. 90513, which suspended the proposed new rates pursuant to Public Utilities Article ("PUA"), *Annotated Code of Maryland*, § 4-204(b)(2) for 270 days from their original effective date.[6] That Order also set a deadline for the filing of petitions for intervention and scheduled a virtual prehearing conference.

A prehearing conference was conducted on March 15, 2023, at which the Commission granted the Petitions to Intervene of the following Parties: United States Department of Defense ("DOD"); IBEW Local 410 ("IBEW"); the Baltimore Washington Construction and Public Employees Laborers' District Council ("BWLDC"); Sierra Club; Interstate Gas Supply, Inc. d/b/a IGS Energy, NRG Energy, Inc., Vistra Corp., and WGL Energy, Inc. (the "Coalition"); Montgomery County, Maryland; Prince George's County, Maryland; and Walmart, Inc. On April 20, 2023, the Commission granted the petition to intervene of the National Railroad Passenger Corporation ("Amtrak"). Also participating

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[4] Order No. 89482 in Case No. 9618.

[5] The MYP 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 MYP); (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 MYP adjustments; and (vi) contain adequate reporting requirements. The Commission finds that BGE's MYP meets the minimum requirements for filing a multi-year rate plan pursuant to the MYP Pilot Order.

[6] Case No. 9692, *Baltimore Gas and Electric Company's Application for an Electric and Gas Multi-Year Plan*, Order No. 90513 (Feb. 21, 2023).

were the Maryland Office of People's Counsel ("OPC") and the Maryland Energy Administration ("MEA").

Order No 90544, issued March 15, 2023, set a procedural schedule for filing of testimony, hearings for cross-examination of witnesses, filing of briefs and reply briefs.[7] It also set forth procedures for discovery and directed the Parties to arrange hearings for receipt of public comment.

Hearings for the purpose of soliciting comments from the public were held on August 9, 2023, August 23, 2023, and September 20, 2023. Written comments were also solicited from the public.

Additional testimonies and Exhibits by BGE and other parties were filed on April 11, April 14, June 19, June 20, July 25, July 27, July 31, August 1, August 18, August 23, August 24, August 25, August 28, August 31, September 1, September 7, and September 12, 2023.

A trial-type evidentiary hearing was held on August 30 and 31, and September 5, 6, 7, and 8, 2023, during which the Commission received oral testimony and admitted pre-filed Testimonies and Exhibits as listed in Appendix C.

[7] Case No. 9692, *Baltimore Gas and Electric Company's Application for an Electric and Gas Multi-Year Plan*, Order No. 90544 (March 15, 2023).

DISCUSSION AND FINDINGS

I. Preliminary Matters

A. OPC Request to Terminate the MYP

OPC requests that the Commission reject BGE's MYP and terminate the MYP pilot.[8] OPC observes that PUA § 7-505(c) authorizes the Commission to adopt an alternative form of regulation only if it (i) protects consumers; (ii) ensures service quality, availability, and reliability; and (iii) is in the public interest, including shareholder interests. OPC argues that the results so far of the MYP rate construct demonstrate that the MYP fails to protect consumers and does not serve the public interest beyond benefiting utility shareholders. *See* OPC witnesses Alvarez-Stephens, asserting: "the MYP pilot has fared abysmally for customers; extremely well for utilities; and added significant litigation and administrative burdens for Staff, OPC, and other stakeholders. By any measure, the utilities win, and customers lose under [the MYP.]"[9]

OPC witnesses Alvarez-Stephens argue that the MYP structure encourages unnecessary utility capital spending by shifting the risks of overspending to customers.[10] In particular, they argue that in a traditional rate case, utilities face a significant risk of cost disallowance for imprudence when they over invest; however, in an MYP, there is no consequence to proposing grid investments that might be cost ineffective, deferrable, or inappropriate. Alvarez-Stephens argued that work plan pre-approval shields utilities from the risk of prudence disallowance and it encourages utilities to propose high-cost, capital-

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[8] OPC Initial Brief at 7-8.
[9] Alvarez-Stephens Direct at 16.
[10] *Id*. at 40-41. *See also* Alvarez-Stephens Direct, Exhibit PJA-3 – Paul Alvarez, Dennis Stephens *et. al., Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers.*

intensive projects. Alvarez-Stephens stated: "A utility has nothing to lose, and everything to gain, by proposing investments in an MYP that they would not make under standard ratemaking. Moral hazard in plan development, combined with a lack of cost disallowance risk and information asymmetry mitigation, inflates the capital spending the utilities are proposing in MYPs."[11]

Alvarez-Stephens argued that approval of forecasted utility work plans results in capital investments that are almost impossible to challenge as imprudent.[12] They claimed that a utility would respond to any challenge by arguing that its plan was presented in advance, and that any opposition to the investments proposed in its plan should have been challenged by stakeholders before the capital was spent. They further argued that a regulator would be unlikely to disallow recovery of excess spending because it would face arguments by the utility that the disallowance would harm customers by increasing a utility's cost of capital. Alvarez-Stephens also claimed that the reconciliation process of an MYP eliminates utility incentives to reduce spending.[13] They argue that under an MYP, utilities possess the opportunity to recover overspending through the adjustment rider, which discourages cost reductions. In contrast, traditional ratemaking encourages cost-containment by rewarding utilities for lowering operating costs and penalizing utilities for overspending.

Alvarez-Stephens further contended that MYPs present significant challenges for regulators and stakeholders who must invest substantial time and resources to effectively evaluate utility capital investments and identify imprudent proposals. They argued that the

[11] Alvarez-Stephens Direct at 41.
[12] *Id*. at 37.
[13] *Id*. at 20-21.

required analysis of the utility's grid operations, technologies employed, and approach to system planning and asset management cannot be done effectively during an 18-week MYP discovery period.[14] Alvarez-Stephens further argued that the MYP format incentives the utility to propose more expansive and excessive capital work plans, which will challenge the capacity of stakeholders and the Commission to effectively assess the utility's proposals.[15]

Regarding the public interest standard, OPC argues that the MYP does not provide any unique public interest benefits.[16] OPC contends that MYPs do not in themselves advance State policies, and any improved transparency available through the present MYP, such as distribution system planning, should be available in a traditional rate case as well. Moreover, OPC claims that MYPs do not support rate gradualism or predictability; to the contrary, the weaker cost-containment inherent in MYPs "all but ensures precipitous rate increases over an MYP period."[17]

Given that BGE's current MYP rates expire on December 31, 2023, OPC witness Effron developed a non-MYP revenue requirement for 2024.[18] OPC argues that this non-MYP revenue requirement would ensure just and reasonable rates and allows for a transition away from MYPs. However, if the Commission does not reject the MYP format for this rate case, OPC asserts that the Commission should complete the lessons learned process before approving another MYP.

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[14] *Id*. at 39.
[15] *Id*. at 36-37.
[16] OPC Initial Brief at 12.
[17] *Id*. at 13.
[18] Effron Direct at 4-5; Exhibit DJE-1; Exhibit DJE-2.

BGE opposes OPC's request to terminate the MYP. The Company asserts that MYPs are good for customers by adding transparency. BGE states that MYPs afford stakeholders the opportunity to review and challenge utility work plans and to ensure that ultimately there is alignment between the Commission and the utility as to the work that will be performed.[19] In contrast, BGE asserts that traditional historical rate cases are backward-looking and do not provide transparency or an opportunity for review of work plans prior to the utility investments being made. BGE further asserts that the reconciliation process encourages cost control, because its asymmetrical design keeps risks of forecasting error on the utility.[20] Specifically BGE witness Frain argued that the reconciliation process protects customers because they will never pay more than actual utility costs, and customers are held harmless in the event that a utility underspends, as customers are provided carrying costs at the utility's authorized rate of return.[21] Given the magnitude of rising costs BGE has experienced, Mr. Frain testified that without an MYP, BGE would be required to file a rate case with the Commission case annually or more frequently.[22] Additionally, he asserted that MYPs provide the Commission with the opportunity to set more gradual and predictable rates.

BGE witness Frain further argued that the MYP is an important tool for the Commission, utilities, stakeholders, and customers to continue moving forward with the State's energy policies and the transition to a more resilient and clean energy future for Maryland. BGE witness Case asserted that BGE has included targeted initiatives in its

[19] BGE Initial Brief at 16.
[20] *Id*., citing *Re Delmarva Power and Light Co*., Case No. 9681, Order No. 90445 (Dec. 14, 2022) at 24-25.
[21] Frain Rebuttal at 46.
[22] Hr'g. Tr. at 884 (Frain).

MYPs that were specifically designed to advance State policy goals for electrification, safety, reliability, and resiliency, which would have been difficult or impossible for BGE to make under a traditional ratemaking framework.[23]

Mr. Case also asserted that the Commission held a lessons-learned process following the Case No. 9645 proceeding and considered the actual experiences to date in Case No. 9645 and Case No. 9692.[24] Mr. Case stated that BGE has been and continues to be willing to make improvements to the MYP process so that all stakeholders may continue to realize the benefits of MYPs.

BGE witnesses Frain and Case opposed OPC's request to terminate BGE's current MYP proceeding. To the extent the Commission wanted to address OPC's issues going forward, Mr. Frain argued that OPC's request to terminate the MYP should be considered through a broad proceeding that includes all stakeholders who participated in the proceeding to determine the original MYP structure, and allows for a thoughtful and measured consideration of any changes.[25] He argued it would be unfair to adopt OPC's recommendation in the context of an individual utility MYP proceeding.

Commission Decision

The Commission declines OPC's request to terminate the instant MYP proceeding and convert it into a traditional rate case. The Commission finds that it would contravene BGE's due process rights to transition the rate case at this time, after Commission notices established this proceeding as an MYP and the parties largely proceeded on that basis. Additionally, the Commission agrees with BGE that a general proceeding, open to all

[23] Case Rebuttal at 5.
[24] *Id*. at 4-5.
[25] Frain Rebuttal at 46.

stakeholders, is the appropriate venue to consider the Statewide evaluation of MYPs, including potential modifications or termination. The Commission finds that it would not be appropriate to terminate MYPs in the confines of a particular utility's rate case.

Nevertheless, the Commission finds that OPC has raised important issues regarding MYPs and whether they are in the best interest of ratepayers and other stakeholders, and whether they are in the public interest in general, consistent with PUA § 7-505(c). For example, OPC witnesses Alvarez-Stephens raised a fundamental question regarding whether the MYP structure encourages unnecessary utility capital spending by shifting the risks of overspending to customers.[26] Without the discipline of cost disallowance for imprudent overinvestment inherent in a traditional rate case, OPC fairly questions whether the utility in an MYP proceeding has an incentive to inflate grid investment proposals.[27] Additionally, OPC raised important questions regarding the resources of regulators and stakeholders to properly evaluate utility MYP proposals, given the need to delve deeply into a utility's grid operations, technologies employed, and system planning and asset management, and whether modifications, such as through extended discovery, could mitigate this issue.

BGE correctly points out that the Commission has already undertaken a limited-lessons learned proceeding. Specifically, after the Commission issued Order No. 89678 in December 2020, Staff commenced a lessons learned process in 2021, which led to the filing of a Lessons Learned Report filed with the Commission by Staff, BGE, OPC, and

[26] Alvarez-Stephens Direct at 40-41. See also Alvarez-Stephens Direct, Exhibit PJA-3 – Paul Alvarez, Dennis Stephens et. al., Alternative Ratemaking in the US: A Prerequisite for Grid Modernization or an Unwarranted Shift of Risk to Customers.

[27] Staff witness Valcarenghi echoed this concern, stating: "There's no cost controls with respect to the specific budget components within the budget that's reflected in rates." Hr'g. Tr. at 1616 (Valcarenghi).

Montgomery County.[28] The Lessons Learned Report included several consensus recommendations to improve the multi-year plan process and enhance benefits such as transparency, including revisions to MYP filing requirements, which the Commission approved for BGE's current Case No. 9692 MYP in Order No. 90401[29] and Order No. 90480.[30]

Notwithstanding BGE's observation, the Commission has not concluded the lessons-learned process. Instead, in approving BGE as the Pilot Utility, the Commission intended that a full lessons-learned proceeding would follow the completion of the Company's first MYP—which does not occur until December 31, 2023. In the Commission's Order Establishing a Multi-Year Rate Plan Pilot, Order No. 89482, the Commission observed that the purpose of the Pilot is to "gain additional experience and lessons learned regarding MRP filings…"[31] After conducting a lessons-learned proceeding following the expiration of the Pilot Utility's first MYP, the Commission stated that it would proceed with the adoption of regulations, if appropriate. Accordingly, the Commission grants OPC's request to commence a lessons-learned process to evaluate the effectiveness of MYPs in Maryland and to consider whether they are in the public interest. BGE does not oppose that inquiry. BGE witness Case stated that BGE has been and

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[28] Case No. 9645, Baltimore Gas and Electric Company's Application for an Electric and Gas Multi-Year Plan, Order No. 89678 (Dec. 16, 2020).
[29] Case No. 9645, Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan, Order No. 90401 (Oct. 28, 2022).
[30] Case No. 9645, Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan, Order No. 90480 (Jan. 23, 2023).
[31] Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for An Electric Company or a Gas Company, Order No. 89482 (Feb. 4, 2020) at 1, n. 2.

continues to be willing to make improvements to the MYP process through a lessons-learned proceeding.[32]

The remainder of this Order therefore addresses BGE's rate request as an MYP, with the understanding that a lessons-learned process will follow the completion of BGE's first MYP. Nevertheless, the Commission observes that Order No. 89482 contains specific provisions for an off-ramp process, which would warrant the Commission's intervention to modify or terminate the MYP.[33] In that order, the Commission held that the off-ramp provision was a necessary counterpart to the Pilot Utility's three-year stay-out provision, and that the off-ramp would become applicable in the event of extraordinary circumstances that call into question whether the existing rates are just and reasonable.[34] Based on the results of the lessons-learned proceeding, as well as the Future of Gas proceeding, the Commission may consider invocation of the off-ramp provision.

B. Conditioning Approval on Compliance with Maryland's Utility Prevailing Wage Law

The Philadelphia-Baltimore-Washington Laborers' District Council ("PBWLDC") argues that the Commission should condition approval of BGE's MYP application on a demonstration by BGE of compliance with PUA § 5-305 (the "Utility Prevailing Wage Law). Specifically, PBWLDC requests that any approval of a rate increase and any subsequent reconciliation in this proceeding be contingent on the submission by BGE of evidence that its contractors and subcontractors employed on projects covered by the Utility Prevailing Wage Law are compliant with the law's requirement to pay its employees

[32] Case Rebuttal at 4-5.
[33] Order No. 89482 at 3.
[34] *Id*. at 30.

no less than the prevailing wage and fringe benefit contribution rate in the locality where the work is being performed.[35] PBWLDC further asserts that BGE should provide documentation that includes: (i) a list of capital projects and O&M activities that are subject to the law; (ii) the prevailing wage determination for covered occupations; and (iii) evidence that the contractor is aware of the lawful rates, and is compliant with the law.

PBWLDC witness Lanning asserted that contracting expenditures are a significant driver of BGE's capital spending and O&M costs over the MYP period. He argued that BGE is reliant on outside contractors to perform vital safety and reliability services on its system, including underground cable replacements, pipeline installation and maintenance, vegetation management, leak remediation, new business and gas residential relocates, and substation performance.[36] He contended that expenditures paid by BGE to outside contractors comprise a significant portion of BGE's forecasted O&M and capital expenditures in this proceeding. Specifically, he estimated that BGE's MYP includes contractor expenditures totaling approximately $3.3 billion.[37]

Mr. Lanning testified that not all contractors and subcontractors of BGE covered projects are paying their employees the prevailing wage.[38] Mr. Lanning asserted that in response to data requests, BGE stated that it was not aware of any change orders submitted by BGE contractors to cover any additional costs related to prevailing wage implementation.[39] Mr. Lanning concluded that the absence of change orders since the law went into effect indicates that contractors have not increased the wages for workers on

[35] PBWLDC Initial Brief at 1.
[36] Lanning Direct at 5.
[37] *Id*. at 4.
[38] *Id*. at 6.
[39] *Id*. at 7-8.

covered projects. Mr. Lanning stated that surveys of workers at BGE construction sites found 86% were not being paid their lawful wages.[40] He also argued that BGE has not performed any audits to verify contractor compliance with the Utility Prevailing Wage Law.[41]

BGE witness Dickens argued that the Commission should reject PBWLDC's proposal to link BGE's request for rate relief to its compliance with the Utility Prevailing Wage Law.[42] He observed that the Utility Prevailing Wage Law was amended to explain that the prevailing wages to be paid pursuant to the law would be determined solely by the Commissioner of Labor and Industry, and that the Maryland Department of Labor would be responsible for enforcement of the law.[43] Accordingly, he argued that PBWLDC should direct any claims of non-compliance to the Maryland Department of Labor.

Mr. Dickens argued that BGE has demonstrated that it requires its contractors to comply with the Utility Prevailing Wage Law.[44] He stated that the Commission denied an earlier request of the PBWLDC to require that utilities covered by PUA § 5-305 be subject to a reporting requirement involving the submission of wage data by its contractors and subcontractors. He noted that in lieu of granting PBWLDC's request, the Commission determined that "addressing the prevailing wage requirements of PUA § 5-305 through contractual terms between the utilities and their contractors and subcontractors is an appropriate mechanism" of demonstrating compliance, and it directed each utility in Maryland to submit an affidavit acknowledging its obligation under the Utility Prevailing

[40] Lanning Surrebuttal at 4.
[41] *Id*. at 7.
[42] Dickens Rebuttal at 33-34.
[43] *Id*. at 29-30.
[44] *Id*. at 30.

Wage Law and explain how it will comply with this law.[45] BGE filed the required affidavit on March 1, 2023.[46] Mr. Dickens asserted that, in accordance with the information provided in that affidavit, BGE complies with the Utility Prevailing Wage Law by requiring all of its contractors and subcontractors to comply with the law.

In his surrebuttal testimony, Mr. Lanning argued that BGE's affidavit does not satisfy the Commission's Order directing utilities to comply with the Utility Prevailing Wage Law.[47] He argued that given the apparent widespread non-compliance with the Utility Prevailing Wage Law, the Commission should find that BGE's standard terms and conditions are not sufficient for demonstrating compliance with the law.[48]

Commission Decision

The Commission denies PBWLDC's request to condition approval of BGE's MYP application on a demonstration by BGE of compliance with the Utility Prevailing Wage Law. PUA § 5-305(b) requires that an investor-owned electric or gas company shall require its contractors or subcontractors on a project involving the company's underground gas or electric infrastructure to pay its employees not less than the prevailing wage rate determined solely by the Commissioner of Labor and Industry. PUA § 5-305(c) provides that the Maryland Department of Labor shall enforce the requirements under subsection (b) for contractors and subcontractors to pay employees not less than the prevailing wage rate. The law went into effect January 5, 2022. Additionally, PUA § 2-113(a)(2)(iii)

[45] Maillog No. 301134.
[46] Maillog No. 301586.
[47] Lanning Surrebuttal at 2.
[48] *Id*. at 3.

provides that in supervising and regulating public service companies, the Commission shall consider the maintenance of fair and stable labor standards for affected workers.

The Commission addressed the requirements of this law in its February 1, 2023, Order, where the PBWLDC requested that the Commission establish a rulemaking to require utilities to take certain compliance measures with respect to PUA § 5-305. In that order, the Commission directed all utilities to file an affidavit acknowledging their obligation under PUA § 5-305, and explain how it will comply with the Utility Prevailing Wage Law.[49] That order found that addressing the prevailing wage requirements of PUA § 5-305 through contractual terms between the utilities and their contractors and subcontractors is an appropriate mechanism to ensure compliance.[50] The Commission stated that to the extent that a contractor or subcontractor fails to pay a prevailing wage to its employees, the contractor or subcontractor would be in breach of its contract with the utility. However, to ensure that all Maryland electric and gas utilities are affirmatively aware of its obligations under PUA § 5-305, the Commission required that each utility is required to file an affidavit acknowledging this obligation and explain how it will comply with the law.

In response, BGE submitted the affidavit of Frank J. Moffa, Vice President of Projects & Contracts, describing actions the Company took. First, the affidavit stated that BGE sent a notice to contractors in December of 2021 regarding the specific requirements of the Utility Prevailing Wage Law. Second, the affidavit stated that "BGE has incorporated into its standard contractual terms and conditions requirements that its

[49] Maillog No. 301134.
[50] *Id*. at 5-6.

contractors and subcontractors comply with applicable laws, which would include paying the prevailing wage to their employees working on covered projects."[51] The Commission finds that BGE is in compliance with its February 1, 2023 order.

The Commission further notes that, pursuant to the provisions of PUA § 5-305(c), compliance responsibilities are within the domain of the Maryland Department of Labor. That statute clearly provides that the Maryland Department of Labor shall enforce the requirements for contractors and subcontractors to pay employees no less than the prevailing wage rate. Additionally, the Commission observes that the Department of Labor has not yet published prevailing wages applicable to covered utility projects.[52] The Commission finds that conditioning MYP approval on BGE submitting the additional compliance information requested by PBWLDC is outside of the scope of this base rate proceeding. The Commission agrees with BGE that a base rate case is not the appropriate forum to address a utility's compliance with the Utility Prevailing Wage Law.[53] Accordingly, the Commission denies the request of PBWLDC to condition approval of the MYP on BGE's submission of additional information to demonstrate compliance with the Utility Prevailing Wage Law.

[51] Maillog No. 301586.
[52] Mr. Dickens testified that it is first necessary for Maryland to establish the prevailing wage for each utility job classification in order for contractors to know if they are already paying prevailing wage for those positions or not. Dickens Rebuttal at 32.
[53] Dickens Rebuttal at 34.

II. Revenue Requirement and Adjustments

A. Contingency Costs

BGE witness Vahos testified that contingency costs represent funding included in a project budget to cover exposure to risk.[54] He stated that BGE takes a conservative approach to developing contingency budgets and does not include contingencies for every project. He further claimed that BGE only includes contingency costs when the Company "identifies specific, quantifiable risks regarding the execution of work and reasonably believes that the base forecasted spend does include all likely costs."[55] BGE also only includes contingencies for highly complex, risky projects. Mr. Vahos argued that including contingencies in the MYP will reduce variances that would otherwise need to be addressed through the reconciliation process, which in turn would reduce rate volatility experienced by customers. Finally, Mr. Vahos asserted that rejecting contingency costs penalizes BGE by forcing it to wait until the reconciliation process to recover forecasted and anticipated expenditures.[56]

Staff and OPC argued against inclusion of contingency costs. Staff witness Smith argued that removal of contingency amounts is consistent with the Commission's Order No. 89678 in BGE Case No. 9645.[57] OPC witnesses Alvarez/Stephens asserted that including contingency dollars in MYP capital budgets for a utility with capital bias "does not discourage that utility from spending the contingency; indeed, it encourages such

[54] Vahos Rebuttal at 39.
[55] *Id*. at 40.
[56] *Id*. at 42.
[57] Smith Direct at 17.

utilities to spend all the contingency, and further encourages them to maximize the size of contingencies added to all project capital budgets."[58]

Commission Decision

In BGE's first MYP, the Commission removed budgeted contingencies from the approved electric and gas work plans and budgets. The Commission found that "it would be inappropriate to impose on ratepayers the additional costs of funding a cushion above BGE's best estimate."[59]

In the current case, BGE expresses disagreement with the Commission's previous holding, arguing that the Commission's decision "was based on the common misconception that contingencies are 'a cushion *above* BGE's best estimate,'" when in fact "project costs *inclusive* of the identified contingency is BGE's *best estimate* because contingencies are added when specific, quantifiable risks to the execution of work are identified."[60]

The Commission declines to include contingencies in BGE's approved electric and gas work plans and budgets. As the Commission stated in Order No. 89678, the MYP 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. There are significant information, resource, and expertise asymmetries inherent in the MYP process, which place BGE in the best position among the parties to forecast accurately. BGE's claim that contingencies are part of its estimate is a clever semantic argument; but ultimately, the Commission finds it is in the best interest of ratepayers to base future rates

[58] Alvarez-Stephens Direct at 92.
[59] Order No. 89678 at 43.
[60] BGE Initial Brief at 58. (Emphasis in original).

on the utility's best estimate of quantifiable costs, without the addition of a perceived risk of cost overruns or other contingencies. Moreover, the Commission finds it is appropriate to wait until the reconciliation stage to address potential cost overruns. Consistent with Order No. 89678, the Commission finds 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. Finally, the Commission finds that it would be inappropriate to require customers to pay for overrun costs upfront prior to a prudency review.

B. Inclusion of MYP Reconciliation Regulatory Asset

In Rate Base Adjustment 3, BGE witness Frain proposed that the under-recovered amounts from BGE's first MYP in Case No. 9645, once approved in the current rate case, be included in rate base until such time as they are fully recovered.[61] Specifically, through this adjustment, BGE is requesting recovery of the electric ($10.7 million) and gas ($7.1 million) under-recovered reconciliation for 2021 through the electric Rider 16 and gas Rider 15 Multi-Year Plan Adjustment Riders.[62] In his supplemental direct testimony, Mr. Frain provided his calculations for reconciliation under-recovery for 2022, which he proposed be recovered through the MYP Adjustment Riders. Based upon 2022 actual results, Mr. Frain testified that BGE under-recovered its approved electric distribution revenue requirement by approximately $43.9 million and its gas distribution revenue requirement by approximately $14.8 million.[63]

[61] Frain Direct at 42-43; Frain Exhibit JCF-7.
[62] *Id*. *See also* Direct Testimony of BGE witness Fiery at 3-4 and 56.
[63] Frain Supplemental at 7.

Staff witnesses Smith and Valcarenghi proposed that the Case No. 9645 Reconciliation regulatory asset be removed from rate base, arguing that the inclusion of under-recoveries in forward rate base is contrary to previous Commission orders establishing an MYP Pilot. In particular, Mr. Valcarenghi stated that Order No. 89482 in Case No. 9618 provides that carrying costs shall apply to over-collections only.[64]

In his rebuttal testimony, Mr. Frain argued that there is a distinction between accruing a return in *advance* of authorized cost recovery and putting the under-recovered balance into rate base once the amount has been determined to be prudent and built into rates.[65] He claimed that BGE was not proposing to accrue a return, because "accruing a return entails accreting a balance to include carrying costs before any recovery has been authorized."[66]

<u>Commission Decision</u>

The Commission's holding regarding MYP reconciliation under- or over-recovery was provided in Order No. 89482 in Case No. 9618—the order that established the Pilot MYP.[67] There, the Commission approved an annual informational filing, a consolidated reconciliation in a rate case to be filed in a subsequent rate case, and a final reconciliation after the conclusion of the MYP rate-effective period.[68] Order No. 89482 provided that the Commission will conduct a consolidated reconciliation and prudency review of utility spending during the authorized duration of the effective MYP through the end of the

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[64] See Smith Direct at 29-31, citing Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or a Gas Company, Order No. 89482 (Feb. 4, 2020).
[65] Frain Rebuttal at 31.
[66] Id.
[67] Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or a Gas Company, Order No. 89482 (Feb. 4, 2020).
[68] Baltimore Gas and Electric Company's Application for an Electric and Gas Multi-Year Plan, Case No. 9618, Order No. 89482, at 37-38 (February 4, 2020).

historic test year as part of the rate case. The filing is required to address differences between the forecasted costs and the actual costs of rate base components, at a project level for plant, and operating income components. The Pilot utility is also required to file a final reconciliation and prudency case within 120 days after the final year of the MYP. The prudency review and reconciliation will include costs in the MYP period not previously reviewed. The filing should detail differences between the forecasted costs and the actual costs of rate base components, at a project level for plant, and operating income components.

In Order No. 89482, the Commission adopted an asymmetrical method for the recovery of over- and under-collection of prudent expenditures during the Pilot MYP, providing for carrying costs only in the situation of over-collection, and concluding that no carrying costs would be paid for under-collection. The Commission justified the asymmetry by holding that "the Pilot Utility should bear the risk of forecasting errors."[69] The Commission explained that the utility has far greater information than other stakeholders as well as greater control over its own costs, and found "it is imperative that the utility have strong incentives to develop accurate forecasts and then plan appropriately to stay within the authorized revenue requirement while also not under-investing to the detriment of safe and reliable utility service."[70] The Commission concluded that: "No carrying costs will be paid in cases of under-collection."[71]

In accordance with the requirements of Order No. 89482, the Commission rejects BGE Rate Base Adjustment 3. Given BGE's far greater access to information, it should

[69] Order No. 89482 at 21.
[70] *Id*. at 21-22.
[71] *Id*. at 39.

have a strong incentive to develop accurate forecasts, that neither under- nor over-invest. The Commission does not find Mr. Frain's distinction regarding the timing of the return to be compelling.

C. Amortize COVID-19 Regulatory Asset

BGE witness Frain proposed Operating Income Adjustment 11 and Rate Base Adjustment 4, which provide for the recovery of a second tranche of incremental COVID-19 costs incurred from July 2020 through December 2023 over a five-year period beginning in 2024.[72] Mr. Frain testified that BGE expects this tranche will be the last tranche of incremental cost deferrals for this regulatory asset.

Staff witness Smith proposed to disallow the portion of incremental COVID-19 costs that include incremental uncollectible write-off expenses.[73] Mr. Smith testified that the portion of unamortized costs to be included in rate base to earn a return should be limited to "actual direct COVID-19 related costs, such as personal protection equipment and cleaning costs."[74] Mr. Smith further argued that his adjustment is in line with the Commission's treatment of unamortized costs in Case No. 9645, Order No. 89678; Pepco Case No. 9655, Order No. 89868;[75] and DPL Case No. 9670, Order No. 90098.[76] Mr. Smith testified that in each of those proceedings, the Commission directed that lost revenues and savings should not be included in rate base. Additionally, Mr. Smith testified that in Order No. 89856, the Commission distributed approximately $49.7 million of funds related to the

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[72] Frain Direct at 44. The first tranche of COVID-19 costs were recovered through July 2020 in BGE's first MYP, Case No. 9645.
[73] Smith Direct at 26.
[74] Id.
[75] Case No. 9655, Potomac Electric Power Company's Application for an Electric Multi-Year Rate Plan, Order No. 89868 (June 28, 2021).
[76] Case No. 9670, The Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy, Order No. 90098 (Feb. 15, 2022).

Recovery for the Economy, Livelihoods, Industries, Entrepreneurs, and Families Act ("RELIEF Act") to BGE to reduce or eliminate customer arrearages.[77]

Staff witness Valcarenghi also proposed to remove the COVID-19 incremental uncollectible write-offs, but for a different reason. Mr. Valcarenghi proposed to remove estimated incremental write-off costs from rate base since they are estimated and not actual.[78] He asserted that this treatment of costs is consistent with the Commission's decision in Case No. 9645, Order No. 89678, where the Commission agreed with Staff's proposal to eliminate estimated amounts related to lost revenues.[79]

In his rebuttal testimony, BGE witness Frain opposed Staff's position, arguing that the incremental uncollectible write-offs are appropriately included in the COVID-19 regulatory asset and should earn a return because they represent the real costs of accounts written off, and are not comparable to lost revenues or savings.[80] He stated that: "[S]ince the incremental write-offs are indeed real costs, it is appropriate to apply the same treatment as is applied to all other direct costs and include these costs in rate base."[81] Mr. Frain further asserted that RELIEF Act funds were applied to accounts receivable to reduce the level of uncollectible write-offs, thereby making the incremental uncollectible write-offs deferred in the COVID-19 regulatory asset lower than they otherwise would have been absent RELIEF Act funds. Finally, Mr. Frain stated that if the Commission chooses to exclude the unamortized balance of incremental COVID-19 write-offs from rate base and not allow BGE to recover the related financing costs, then BGE should be authorized to recover those

[77] Public Conference ("PC") No. 53, *Impacts of COVID-19 Pandemic on Maryland's Gas and Electric Utility Operations and Customer Experiences*, Order No. 89856 (June 15, 2021).
[78] Valcarenghi Direct at 31.
[79] *Id*. at 32, citing Case No. 9645, Order No. 89678 at 20.
[80] Frain Rebuttal at 27-28.
[81] *Id*. at 29.

deferred amounts as O&M expense, which would increase the revenue requirement in this rate case proceeding.[82]

Commission Decision

In response to the significant financial implications that utilities were anticipated to face in complying with emergency orders related to COVID-19, the Commission authorized Maryland 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.[83] The Commission found that deferral of such costs was appropriate because the COVID-19 health emergency was outside the control of the utilities and was a non-recurring event. In Order No. 89678, the Commission granted authority for 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.[84] The Commission further directed that "lost revenues and savings not be included in rate base."[85]

The Commission finds that Staff's position is more consistent with the Commission's intent in Order No. 89678 to exclude lost revenues and savings from rate base, than is BGE's position. Accordingly, the Commission accepts Staff's proposal to disallow the portion of incremental COVID-19 costs that include incremental uncollectible write off expenses.

[82] *Id*. at 30.
[83] Case No. 9639, *State of Emergency and Public Health Emergency in the State of Maryland Due to COVID-19*, Order No. 89542 at 2.
[84] Order No. 89678 at 20.
[85] *Id*.

This removal is in accordance with the Commission direction in Case No. 9645 "that lost revenues and savings not be included in rate base." Nevertheless, the Commission accepts Mr. Frain's compromise position that, if the Commission excludes the unamortized balance of incremental COVID-19 write-offs from rate base, as it is doing in this Order, then BGE should be authorized to recover those deferred amounts as O&M expenses. BGE is so authorized.

D. Accelerated Tax Benefits (TCJA)

Through Operating Income Adjustment 20 and Rate Base Adjustment 13, BGE has proposed to provide customers with accelerated tax benefits associated with the Tax Cuts and Jobs Act of 2017 ("TCJA") excess deferred income taxes regulatory liability for unprotected property and non-property over 2024 and 2025.[86] BGE witness Frain testified that these adjustments would result in a more gradual increase over the MYP period by reducing, but not fully mitigating, the initial MYP rate increases starting when the new rates become effective in January 2024 and January 2025.[87] Mr. Frain further stated that the adjustments would provide the remaining gas TCJA benefits to customers in 2024 and the remaining electric TCJA benefits to customers in 2024 and 2025. In total, Mr. Frain testified that $69.7 million of electric and gas tax benefits would be accelerated for customers in 2024 and $32.1 million of electric tax benefits would be accelerated for

[86] The TCJA tax benefits relate to the annual amortization of the regulatory liability arising from changes in BGE's accumulated deferred income tax ("ADIT") balances that were approved by the Commission in its Letter Order issued on January 31, 2018. The ADIT balances were previously recorded at the higher 35% federal income tax rate. As a result of the TCJA, the ADIT balances are now reflected at the lower 21% tax rate. The difference between the ADIT balances at the 35% rate and the 21% rate is referred to as the "excess deferred income tax" regulatory liability.
[87] Frain Direct at 9.

customers in 2025.[88] BGE witness Frain also indicated that the 2024 values would be included within its current offset rider.[89]

Staff witness Smith did not oppose BGE's adjustment.[90] He observed that customers have previously paid for the related taxes and that the adjustment would provide customers with a refund in a more accelerated fashion. Mr. Smith stated that customers would experience a benefit in years 1 and 2 by reducing rate impacts, but that acceleration would result in future customers paying higher rates. Even with the acceleration; however, Mr. Smith stated that approximately $182 million would remain in BGE's electric TCJA excess deferred income taxes regulatory liability at the end of 2026, because the protected property portion of the TCJA regulatory liability would continue to be amortized over approximately 34 years.

Similarly, OPC witness Effron testified that it would be reasonable to accelerate recognition of the tax benefits of the TCJA to mitigate the magnitude of the rate increases in 2024 and to smooth the path of required revenue increases over the term of the MYP.[91] However, Mr. Effron also stated that to the extent other adjustments are made to lower BGE's revenue requirement, such as through reducing BGE's proposed ROE, the accelerated recognition of tax benefits necessary to smooth the year to-year rate increases "can be pared back."[92] Mr. Effron acknowledged; however, that if tax benefits are accelerated, customers in future years will be required to pay higher rates to make up for the benefits conferred on customers in 2024 and 2025.[93] As an alternative to BGE's

[88] *Id*. at 11.
[89] *Id*. at 31.
[90] Smith Direct at 28-29.
[91] Effron Direct at 15.
[92] *Id*. at 17.
[93] *Id*.

approach, Mr. Effron proposed that the amortization of tax benefits could be accelerated by $14.0 million in 2024 and $8.5 million in 2025.[94]

Commission Decision

As Staff witness Smith observed, customers have already paid for the related taxes that have been held by BGE in a regulatory liability.[95] The TCJA was passed on December 22, 2017, and it provides for a significant reduction of the federal corporate income tax rate, from 35 percent to 21 percent. As a result of the passage of the TCJA, BGE's Accumulated Deferred Income Taxes ("ADIT") balances, previously recorded at the higher 35 percent federal income tax rate, were reflected at the lower 21 percent tax rate. BGE placed the difference between those rates into the "excess deferred income tax" regulatory liability for eventual return to customers.[96] In the adjustments proposed in this case, BGE will accelerate the return of those ratepayer funds that were collected at the higher rate. Neither Staff nor OPC objected to BGE's proposal, with both parties acknowledging that the acceleration will mitigate the magnitude of the rate increases in 2024 and smooth the path of required revenue increases over the term of the MYP.[97] Additionally, the faster return of the over-collected money to ratepayers will mitigate intergenerational concerns that would have existed over a multi-decade return of TCJA funds.

The Commission modifies BGE's Operating Income Adjustment 20 and Rate Base Adjustment 13, which provide customers with accelerated tax benefits associated with the TCJA. The Commission will offset BGE's revenue requirement in the same manner as it

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[94] *Id*. at 18-19.
[95] Smith Direct at 28-29.
[96] Order No. 89678 at 28.
[97] Effron Direct at 15; Smith Direct at 28-29. Although OPC witness Effron offered an alternative accelerated TCJA refund schedule, the Commission finds BGE's original proposal most appropriate.

did in Case No. 9645, where a set amount of tax benefits will be utilized to offset the distribution rates through BGE's existing tariffs in 2024 and then the additional use of offsets will be considered annually, if needed. Any revenue impacts from accelerated tax benefits used in 2025 or 2026 will be considered in subsequent reconciliation filings. The amount of offsets will be discussed in the Cost Allocation section below.

E. Establish and Amortize Non-Major Outage Restoration Event Regulatory Asset

BGE witness Frain proposed a change to the treatment of O&M costs incurred for non-major outage events.[98] Specifically, as a result of the volatility of non-major outage events, Mr. Frain proposed that BGE be allowed to establish a regulatory asset for actual non-major outage event O&M costs, to be reflected in forecasted base rates beginning in 2024 with recovery over a five-year period. Mr. Frain proposed these adjustments through Operating Income Adjustments 17 and 18, and Rate Base Adjustments 11 and 12.

Mr. Frain stated that the budgeted unadjusted operating income for the MYP 2 years of 2024-2026 includes \$45.4 million, \$47.7 million, and \$48.4 million of forecasted non-major outage event expenses in each year, respectively, based on the most currently available historical five-year weighted average.[99] Operating Income Adjustment 17 and Rate Base Adjustment 11 remove from O&M the amounts described above and establish a regulatory asset in rate base. Mr. Frain argued that these adjustments would make the recovery of non-major outage events more known and certain and provide for less volatility in the costs reflected in customer rates.

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[98] Frain Direct at 17-19.
[99] *Id*. at 18.

Staff witness Smith opposed BGE's proposal to defer non-major outage event expenses into a regulatory asset.[100] He argued that costs deferred into a regulatory asset are generally costs that are unusual in nature, non-recurring, or extraordinary. Non-major outage events, in contrast, occur regularly on an annual basis, according to Mr. Smith. He therefore asserted that such costs should be included in O&M expenses in the year in which the costs are incurred. Mr. Smith further recommended that BGE use a simple five-year average to calculate non-major outage event costs, rather than a weighted five-year average. Mr. Smith provided these adjustments in Exhibit JAS-22, Exhibit JAS-23, Exhibit JAS-24, and Exhibit JAS-25.

Staff witnesses Lytangia Bunch and Mikhail Shpigelman ("Bunch-Shpigelman") testified that they calculated the average O&M cost related to non-major outage events from 2010 through 2022 to be approximately $25.5 million, and that the cost of storms over the most recent five years (2018-2022) was $37,974,331.[101] In either case, Bunch-Shpigelman testified that the amount BGE has requested to be deferred to a regulatory asset each year is considerably higher than the averages Staff calculated. Additionally, Bunch-Shpigelman asserted that the establishment of a regulatory asset should only be considered in situations where annual costs vary significantly from year to year, which has not been demonstrated by BGE in this case. Bunch-Shpigelman calculated the average variance in O&M costs for non-major outage events from 2018-2022, and determined that the variance was not sufficient to demonstrate the need to establish a regulatory asset to smooth out rate recovery.[102] Accordingly, Bunch-Shpigelman recommended that the Commission disallow

[100] Smith Direct at 25.
[101] Bunch-Shpigelman Direct at 15-16.
[102] *Id*. at 17.

BGE's proposal to move non-major events into a regulatory asset, and that instead, the Company use the five-year average of all non-major events from 2018-2022 and apply that figure to cover the costs of non-major events for each year of this MYP.[103]

In his rebuttal testimony, BGE witness Frain asserted that contrary to Staff's arguments, non-major outage event frequency and severity do vary significantly from year to year.[104] Although he acknowledged that non-major outage events occur annually, Mr. Frain asserted that these costs are volatile in both frequency and severity. Mr. Frain further stated that there is Commission precedent for allowing regulatory asset treatment for non-major outage events. He stated that in Case No. 9336, Order No. 86441, the Commission authorized Potomac Electric Power Company to defer certain prudently incurred 2013 outage event costs in a regulatory asset to be amortized and recovered over a five-year period.[105] Finally, Mr. Frain testified that if the Commission rejects BGE's adjustments, these costs would need to be reflected in the 2024-2026 MYP base rates as O&M, resulting in required revenue increases of $40.4 million, $30.4 million, and $18.9 million for 2024, 2025, and 2026, respectively, compared to the Company-proposed customer rates.[106]

Commission Decision

The Commission agrees with Staff that the O&M costs of non-major outage events do not vary significantly enough to justify establishing a regulatory asset in this case. The costs are not unusual in nature, non-recurring, or extraordinary. BGE's proposal to

[103] *Id*.
[104] Frain Rebuttal at 7-8.
[105] *Id*. at 9-10, citing Case No. 9336, In the Matter of the Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for the Distribution of Electric Energy, Order No. 86441 at 37. Mr. Frain also cited Case No. 9230, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in Its Electric and Gas Base Rates*, Order No. 83907.
[106] *Id*. at 10.

establish a regulatory asset for non-major outage event O&M costs with recovery over a five-year period is therefore denied. Instead, BGE is directed to use the five-year average of all non-major outage events from 2018-2022 and apply that figure to cover the costs of non-major outage events for each year of this MYP.[107]

F. Amortize Rate Case Expenses

BGE witness Frain proposed Operating Income Adjustment 9, which reduces operating income to reflect the amortization of rate case expenses associated with the current MYP proceeding. Mr. Frain testified that the adjustment is consistent with Commission precedent allowing for recovery of rate case expenses over a three-year period.[108]

Staff witness Smith observed that Staff recommended removing BGE's electrification program from consideration in this MYP, arguing that the program did not properly fit within the contours of a base rate case, but would be better addressed in the EmPOWER MD proceeding.[109] Consistent with that recommendation, Mr. Smith testified that rate case expenses associated with a study performed in support of System Hardening and Resiliency Enhancement ("SHARE") should also be removed, because the costs

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[107] Another issue related to storm costs was Staff witness Dererie's review of Major Outage Event reconciliation costs for 2022. Ms. Dererie could not conclude if the costs BGE incurred on a per customer basis were reasonable due to insufficient information. Ms. Dererie recommends BGE produce a cost benchmarking evaluation for these costs to see how BGE compares to its peers. Ms. Dererie intends to either use this information to recommend an adjustment for 2022 storm costs during the reconciliation review in 2024 or to identify opportunities to reduce costs (Dererie Surrebuttal at 15-16). BGE opposed this raising issues with the use of such benchmarking and also argued that the prudency review of 2022 major outage event costs should happen in the instant case (BGE Initial Brief at 49-50). The Commission agrees that such a benchmarking analysis should be produced going forward when significant outage event costs similar to 2022 occur and directs BGE to produce the analysis requested by Staff in the current case. If Staff later attempts to make a disallowance for 2022 costs outside of the current case, the Commission will consider the grounds for such an adjustment then.
[108] Frain Direct at 43, citing Case Nos. 9326, 9406, 9484, 9610, and 9645.
[109] Smith Direct at 23.

support BGE's electrification proposals.[110] Those SHARE expenses amount to $338,500. Staff witness Valcarenghi also recommended removing rate case expenses related to the SHARE study from BGE's proposed Operating Income Adjustment 9.[111]

BGE witness Frain opposed Staff's recommendation. Mr. Frain asserted that the SHARE study did not support the BGE's customer electrification program, but instead directly supported the resiliency efforts addressed in the direct testimony of BGE witness Wright.[112] In particular, Mr. Frain argued that the SHARE study leveraged a storm resilience model that evaluates individual hardening projects across the BGE system to develop a plan to harden the system and reduce the magnitude and/or duration of disruptive storm events. Mr. Frain further argued that BGE should not be punished for incurring costs associated with the development of innovative proposals to enhance the safety, reliability, and resilience of its system.[113] Accordingly, he asserted that SHARE costs should be considered an appropriate rate case expense.

In her rebuttal testimony, BGE witness Wright testified that BGE did not apply for Infrastructure Investment and Jobs Act ("IIJA") funding support for the SHARE project because that project focused on benefits to overall BGE customers and not solely to disadvantaged communities or other underserved populations. Instead, BGE applied for a Grid Resilience and Innovation Partnerships ("GRIP") Program grant, which does focus on disadvantaged and underserved communities.[114]

[110] *Id*.
[111] Valcarenghi Direct at 36; Exhibit DLV-12.
[112] Frain Rebuttal at 25.
[113] Hr'g. Tr. at 874-75 (Frain).
[114] Wright Rebuttal at 16.

In his rebuttal testimony, Staff witness Smith stated that Staff mistakenly identified SHARE costs as electrification program related rate case expenses in his direct testimony.[115] Nevertheless, Mr. Smith continued to support removal of SHARE rate case expenses, stating that Staff witness Austin proposed removing approximately $109 million of capital project spend related to BGE's Resilience Investment Plan (described below). Staff witness Valcarenghi continued to recommend disallowance of these rate case expenses as they were solely for electric operations.[116]

Staff witness Austin provided several criticisms of BGE's Resilience Investment Plan, including that BGE is beginning to experience diminished returns on reliability investments.[117] Additionally, he faulted BGE for failing to submit its Resilience Investment Plan as a candidate for IIJA funding under the U.S. Department of Energy's ("DOE") $10.5 billion GRIP Program.[118] He also argued that there are no agreed upon resiliency standards and objectives and no agreed upon metrics by which to measure a utility's success in meeting those standards and objectives. Finally, Mr. Austin criticized BGE's choice of consultant in developing its Resilience Investment Plan. Mr. Austin testified that BGE's consultant—1898 & Co.—is a subsidiary of Burns & McDonnell which is an engineering, procurement and construction firm with significant interests in the planning, analysis, design and construction of electrical distribution system infrastructure.[119]

Staff witness Austin recommended that the Commission "shelve" BGE's Resilience Investment Plan and establish an administrative docket to consider issues related

[115] Smith Surrebuttal at 11.
[116] Valcarenghi Surrebuttal at 18.
[117] Austin Direct at 4 and 43-44; Staff Engineering Division Review of Proposed System-Wide Reliability Standards for 2024 – 2027, at 13-14.
[118] Austin Direct at 48 and 85-86.
[119] *Id*. at 87.

to resiliency, such as the implementation of resiliency standards, objectives, and metrics by which to measure the effectiveness of resiliency investments. He also recommended that the administrative proceeding address resiliency reporting requirements and penalties for failure to meet agreed upon resiliency standards and objectives.[120] Given Mr. Austin's testimony, Mr. Smith testified that Staff's position is that SHARE costs should be removed from BGE's rate case expense.

Finally, Staff witness Valcarenghi testified in his surrebuttal testimony that nothing in BGE's responses to Staff data requests indicates that any of the SHARE expenses relate to BGE's gas operations, but instead indicate that the costs pertain solely to BGE's electric operations.[121] Accordingly, Mr. Valcarenghi recommended removal of SHARE costs that are included in gas rates.

<u>Commission Decision</u>

The Commission accepts Staff's adjustment to remove from BGE Operating Income Adjustment 9 those rate case expenses associated with the SHARE study. As more fully discussed below, the Commission agrees with Staff that removal of BGE's Resilience Investment Plan is appropriate. The Commission will also establish an administrative docket to consider issues related to resiliency, including the implementation of resiliency standards, objectives, and metrics by which to measure the effectiveness of resiliency investments. The removal of rate case expenses associated with the study performed in support of SHARE is therefore appropriate. This adjustment results in expenses in the amount of $338,500 being removed from BGE's Operating Income Adjustment 9.

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[120] *Id*. at 87-88.
[121] Valcarenghi Surrebuttal at 18.

G. Supplier Consolidated Billing

BGE witness Frain testified that BGE has begun incurring costs related to supplier consolidated billing ("SCB") that are reflected in its revenue requirement.[122] BGE witness Vahos also submitted testimony in support of including these costs.[123] Mr. Frain asserted that SCB costs were authorized by the Commission in Order No. 90046, and that BGE has been working to offer SCB by the December 2023 deadline imposed by that order.[124] Mr. Frain further stated that BGE's electric rate base includes a regulatory asset for certain consultant costs associated with the development of electronic data interchange ("EDI") related to the SCB project.[125] Mr. Frain noted that at the time of filing his direct testimony, the Commission had not yet determined how supplier consolidated billing costs should be recovered or from whom they should be recovered.

Staff witness Jiang challenged BGE's testimony regarding SCB costs. Mr. Jiang argued that BGE's costs for internal labor associated with SCB are inconsistent within its own tracking system.[126] He further asserted that there appears to be inconsistency between BGE's internal systems, resulting in ambiguity over the accuracy of SCB costs included in BGE's revenue requirement. Based on BGE's purported lack of adequate response to Staff discovery requests, Mr. Jiang argued BGE has not demonstrated that it can provide documentation showing how the costs of SCB were tracked and procured. In particular, Mr. Jiang stated that he was unable to verify how BGE's contract labor costs were incurred,

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[122] Frain Direct at 25.
[123] *See* Vahos Direct at DMV-6.
[124] Case No. 9461, *In the Matter of the Petition of NRG Energy, Inc., Interstate Gas Supply, Inc., Just Energy Group, Inc., Direct Energy Services, LLC, and ENGIE Resources, LLC for Implementation of Supplier Consolidated Billing for Electricity and Natural Gas in Maryland*, Order No. 90046 (Jan. 19, 2022).
[125] Frain Direct at 25-26.
[126] Jiang Direct at 6 and 13.

and therefore could not conclude that the costs were prudent.[127] Finally, Mr. Jiang testified that he could not determine whether BGE's SCB costs were incremental or part of BGE's embedded costs.[128] Accordingly, Mr. Jiang recommended that the Commission remove SCB capital and O&M expenses from BGE's revenue requirement.

In his rebuttal testimony, Mr. Vahos opposed Staff's recommendation, though he acknowledged that BGE "made some inadvertent misstatements" during the discovery process "that created unintended confusion and uncertainty for Staff."[129] Nevertheless, Mr. Vahos stated that BGE provided additional information to Staff in discovery that addressed the concerns regarding employee time tracking and contractors and the SCB procurement process. In response to Mr. Jiang's concern regarding incremental costs, Mr. Vahos testified that none of the costs incurred in the SCB project are reflected elsewhere or recovered from customers through any other BGE project. Additionally, Mr. Vahos stated that the SCB project is a stand-alone enhancement to BGE's existing billing system that solely benefits suppliers choosing to use SCB.

In his surrebuttal testimony, Mr. Jiang asserted that BGE's process for obtaining contractor labor for SCB was not as transparent and competitive as possible to reduce costs, and that an RFP would have been a superior method.[130] Mr. Jiang stated that he still had questions regarding how BGE calculated internal labor costs as they relate to SCB.[131] With regard to BGE's process for procuring contract labor, Mr. Jiang testified that BGE's Park program purported to produce lower costs in a shorter timeframe than using an RFP.

[127] *Id*. at 11.
[128] Mr. Jiang testified that BGE estimated its SCB costs over the course of MYP 2 would be $8,339,557 for electricity and $4,506,111 for natural gas.
[129] Vahos Rebuttal at 19-20.
[130] Jiang Surrebuttal at 7.
[131] *Id*. at 10.

However, Mr. Jiang testified that he could not validate BGE's claims because BGE did not track certain data and it did not provide sufficient information regarding its third-party assessment.[132] Noting that Accenture was awarded the SCB work as part of BGE's Park process, Mr. Jiang asserted that it was not possible to know whether a different vendor could have provided the same contract labor at a lower cost than what Accenture provided, since no other vendors were involved.[133] Finally, given the absence of data provided by BGE, Mr. Jiang testified that he was uncertain whether the number of hours Accenture employees worked is appropriate for the list of work they completed.[134] He therefore recommended that half of the contracting labor costs for both capital and O&M related to SCB in BGE's MYP be removed from the revenue requirement. He also recommended that the approved SCB costs not be recovered until the SCB program begins.[135]

Commission Decision

The implementation of SCB in the Maryland electricity and natural gas markets was authorized by the Commission on May 7, 2019, through Order No. 89116.[136] In that order, the Commission found SCB is consistent with the goals and mandates of the Customer Choice Act and the Natural Gas Act, and that SCB represents the next logical step for Maryland to fully implement the restructuring goals of those statutes.[137] Accordingly, the Commission directed that a workgroup led by Staff be convened that is comprised of representatives of the retail suppliers, the utilities, OPC, MEA, and other

[132] *Id*. at 14.
[133] *Id*. at 16.
[134] *Id*. at 19.
[135] *Id*. at 21.
[136] Case No. 9461, *In the Matter of the Petition of NRG Energy, Inc. et al. for Implementation of Supplier Consolidated Billing for Electricity and Natural Gas in Maryland*, Order No. 89116 (May 7, 2019).
[137] Order No. 89116 at 12, 14, and 16.

interested stakeholders ("the SCB Workgroup") to recommend resolutions to the many implementation details associated with SCB.[138]

On June 27, 2023, the Commission issued Order No. 90696, which addressed the topic of SCB cost recovery.[139] Specifically, the Commission chose Option 5 out of a number of cost allocation possibilities, finding that it best balanced the principles of cost causation, avoidance of barriers to entry, and full and timely recovery of utility costs. That option requires customers to pay SCB implementation costs upfront, which will ensure that utilities are made whole for their investments and will also prevent the imposition of overwhelming costs to a nascent SCB industry. Suppliers, however, will be required to repay customers over time, which will meet the principle of cost causation.[140] Finally, the Commission stated that Order No. 90696 does not address issues of prudency, which are best addressed in the context of a rate case.

Staff witness Jiang has challenged the prudency of BGE's SCB expenditures in this rate case, alleging generally that BGE has not presented sufficient information for Staff to verify that the costs were reasonable and prudently incurred. The Commission finds, however, that BGE has adequately met its burden. During the evidentiary hearing, BGE witness Vahos presented live rejoinder testimony that addressed some of the deficiencies that Staff raised. In particular, Mr. Vahos testified about the scale of SCB costs, stating that to implement SCB, BGE was required to develop completely new functionality for its

[138] *Id*. at 23.
[139] Case No. 9461, *In the Matter of the Petition of NRG Energy, Inc. et al. for Implementation of Supplier Consolidated Billing for Electricity and Natural Gas in Maryland*, Order No. 90696 (June 27, 2023).
[140] Order No. 90696 at 21.

billing system.[141] Regarding the competitive process for procuring BGE's vendor, Mr. Vahos stated that BGE developed a strategic partnership with key vendors who are already familiar with BGE's systems, providing them work in the area of customer billing in exchange for a lower price for customers.[142] He testified that this arrangement enabled BGE to experience a 50% improvement in the time it takes to get from a scope of work to an executed contract. He also stated that BGE used a third-party independent validating firm to assess the competitiveness of each project, which determined that BGE experienced a 10% savings for SCB.[143]

The Commission therefore concludes that BGE has met its burden of demonstrating the prudency of its SCB expenditures in this proceeding. Staff's adjustment is therefore denied. Nevertheless, Staff witness Jiang raised several issues that the Commission will scrutinize in BGE's next rate case. In particular, BGE will be required to demonstrate that contracting labor was procured in a way that is transparent and competitive, and the Company will need to provide information relative to how it calculated internal labor costs. Additionally, BGE will be required to provide sufficient information for Staff and other stakeholders to verify the efficacy of any third-party assessment. All of that information should be provided upfront, in the direct testimony of BGE's next rate case. Parties should not have to wait for rebuttal or live rejoinder testimony to obtain information necessary to formulate their litigation position.

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[141] Hr'g. Tr. at 902 (Vahos). He testified that "modern billing systems are extremely complex [and] highly integrated. It's not a small thing to introduce an entirely new set of functionality without robust testing and multiple environments before you ever put something like that in production because if we make a mistake and put something in production that doesn't work, millions of bills could be wrong [and] calls can't be answered appropriately in the call center." *Id*.
[142] Hr'g. Tr. at 903 (Vahos).
[143] Hr'g. Tr. at 903-905 (Vahos).

H. Depreciation

Depreciation is the method companies use to recover the original cost of their investment as well as any net salvage. Net salvage is the difference between the remaining market value of an asset at retirement and its cost of removal.

BGE witness Ned W. Allis provided an overview and explanation of the depreciation study performed for BGE for its proposed MYP. He noted that BGE's depreciation proposal would result in an overall decrease in depreciation expense of $15.1 million as of December 31, 2021. [144] Mr. Allis testified that he used the Maryland Present Value ("MD Present Value") with a discount rate based on the same credit-adjusted risk-free rate ("CARFR") used for its asset retirement obligations ("ARO").[145] He indicated that Commission precedent and previous Staff positions supported using CARFR (at a 4.86% discount rate), as opposed to the utility's rate of return, as the discount rate to calculate the net salvage portion of depreciation rates.[146] Mr. Allis testified that the proposal used the same methods as in previous depreciation studies for estimating service lives and net salvage, and calculating depreciation for the original cost of plant.[147] He stated that he has concerns that continued use of the Maryland Present Value method will result in inefficient future net salvage recovery, "large regulatory asset balances and intergenerational inequity."[148] However, he believed that BGE's proposed depreciation rates for this MYP, using the Maryland Present Value method, are reasonable and a less contentious issue than

[144] Allis Direct at 4.
[145] *Id.*
[146] *Id.* at 4 and 13.
[147] *Id.*
[148] *Id.* at 5.

in other recent cases, as they were developed in the context of Commission precedent and result in an overall decrease in depreciation expense.[149]

BGE witness Allis explained that he performed the depreciation study using the straight line remaining life method/remaining life technique of depreciation, with the average service life procedure.[150] He used the straight line remaining life method of amortization for certain general plant accounts in electric, gas and common plants, resulting in proposed amortization periods similar to those currently used by BGE.[151] Mr. Allis determined BGE's recommended annual depreciation accrual rates in two phases.[152] The first phase consisted of estimating the service life and net salvage characteristics for each depreciable group, by compiling historical data from BGE plant records as well as other electric and gas utilities.[153] For the second phase, Mr. Allis stated that he calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase, by analyzing BGE's accounting entries that record plant transactions from 1938 through 2021.[154] He testified that he used the retirement rate method to analyze each property group, forming a life table that showed an original survivor curve for each group.[155] Mr. Allis applied the widely-utilized Iowa-type survivor curves—which contain the characteristics that utilities generally experience—to interpret the original survivor curves.[156]

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[149] *Id.*
[150] *Id.* at 14.
[151] *Id.* at 16.
[152] *Id.*
[153] *Id.* at 16-17.
[154] *Id.* at 17.
[155] *Id.* at 18.
[156] *Id.*

Mr. Allis also stated that he estimated the net salvage percentages by incorporating historical data from 1975 through 2021 and considered additional factors including other electric and gas company estimates, similar to past studies performed for BGE.[157]

For the second phase, Mr. Allis explained that he estimated the service life and net salvage characteristics for each depreciable property group, using the straight-line remaining life method, using remaining lives consistent with the average service life procedure, and also calculated depreciation rates based on the MD Present Value Method.[158]

BGE witness Vahos provided details about the calculation of the depreciation and amortization ("D&A") expense. He noted that BGE's projected D&A expense in the MYP comprises the baseline D&A expense on the existing plant in service, as of December 31, 2022, and the D&A expense on forecasted plant additions placed into service, net of projected plant retirements, during the bridge period and the MYP years.[159] Mr. Vahos testified that the D&A expense associated with the forecasted plant additions is calculated by categorizing assets into forecasted depreciation groups, comprising one or more individual plant accounts.[160] Each of the individual plant accounts has an associated depreciation accrual rate, forming the basis for 2.42% composite depreciation rate applied to BGE' forecasted plant additions.[161] He stated that the projected D&A expense associated with the total distribution plant additions is calculated by multiplying the forecasted

[157] *Id.* at 21.
[158] *Id.* at 22.
[159] Vaho Direct at 36.
[160] *Id*. at 37.
[161] *Id.*

monthly balance of plant in service by the associated monthly composite depreciation rate.[162]

According to witness Vahos, BGE's new proposed rates are expected to reduce D&A expense by an average of $17.6 million for the MYP period (averaging $16.5 million in 2024, $17.6 million in 2025, and $18.8 million in 2026), relative to the existing rates approved by the Commission in Case No. 9610.[163]

BGE witness Frain testified that the results of the depreciation study show that Operating Income Adjustment 13 and Rate Base Adjustment 6 apply the study's calculated depreciation rates to the projected 13-month average electric distribution, gas and common plant balances as of December 31 of each year of the MYP, and compare the results to the forecasted levels of depreciation expense.[164] He stated that the two adjustments reflect a projected depreciation decrease for both electric and gas totaling $16.5 million for 2024, $17.6 million for 2025, and $18.8 million for 2026, as well as the accumulated depreciation impact.[165]

Staff witness Garren analyzed BGE's depreciation study and compared it with his own proposed depreciation parameters.[166] He recommended a depreciation expense of $149.1 million for BGE's electric plant, compared to BGE's proposed depreciation expense of $168.9 million, concluding that the Company overstated its depreciation expense by $19.7 million.[167] He did not propose an adjustment to BGE's gas and common

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[162] *Id.* at 38.
[163] *Id.* at 39-40.
[164] Frain Direct at 12.
[165] *Id.* at 12-13.
[166] Garren Direct at 6.
[167] *Id.*

plant.[168] Mr. Garren explained that he adjusted the service lives of seven electric accounts: 361.00–Structures and Improvements; 362.00–Station Equipment; 364.00–Poles, Towers and Fixtures; 365.00–Overhead Conductors and Devices; 367.00–Underground Conductors and Devices; 369.20–Underground Service; and 373.20–Underground Street Lighting and Signal Systems.[169]

Although Mr. Garren expressed concern with BGE's use of a CARFR, which he considered more appropriate for use with legal AROs, which are estimated on a more concrete basis, using specific engineering estimates of the labor hours required to perform the needed removal processes, than non-legal AROs.[170] He stated that non-legal AROs are estimated using an unrefined ratio of net salvage to retirements, producing unreliable results.[171] He stated further that while legal AROs are required to take place, no utility is required to incur much of its non-legal ARO costs.[172] However, he found Mr. Allis' proposed discount rate to be reasonable.[173] Mr. Garren proposed that BGE use the Maryland Present Value cost of removal method, consistent with Commission precedent, but accepted Mr. Allis' proposed 4.86% discount rate, based on its recent bond yield.[174]

OPC witness Garrett provided testimony in response to BGE's depreciation proposal. Mr. Garrett used the straight line method, average life procedure, remaining life technique and the broad group model to analyze BGE's actuarial data, which he referred to as the SL-AL-RL-BG system.[175] This system, witness Garrett explained, conforms to

[168] *Id.*
[169] *Id.*
[170] *Id.* at 34.
[171] *Id.*
[172] *Id.*
[173] *Id.* at 35.
[174] *Id.*
[175] Garrett Direct at 10.

the legal standard of depreciation that "the original cost of plant assets . . . [comprises] the proper basis for calculating depreciation expense," and that the proposed depreciation rates are not excessive.[176]

He noted that depreciation should represent an allocated cost of capital to operate, as opposed to a method of determining loss of value, explaining that a utility should receive a return on invested capital through the allowed rate of return as well as in the form of recovered depreciation expense.[177] Mr. Garrett stated that the cost allocation concept also conformed to fundamental accounting principles.[178]

Mr. Garrett analyzed BGE's depreciable property by reviewing the data BGE used to conduct its depreciation study and technical update, using BGE's plant data to develop his proposed depreciation rates, and applying them to BGE's updated plant balances to finalize his determination of depreciation expense.[179] He used service life and net salvage parameters to analyze BGE's depreciable property.[180] For the service life parameter, Mr. Garrett used the retirement rate method, a common actuarial method, to develop an observed life table ("OLT"), showing the percentage of property that survive at each age interval.[181] In turn, he used this information to develop a survivor curve, which he refined by using an "Iowa Curve."[182]

Mr. Garrett compared BGE's service life proposals to the service life proposals he developed, noting that BGE's proposals for several accounts, which were estimated using

[176] *Id.* at 7-8.
[177] *Id*. at 8.
[178] *Id*.
[179] *Id.* at 9.
[180] *Id.* at 11.
[181] *Id.*
[182] *Id.*

Iowa Curves,[183] were too short to accurately reflect mortality characteristics.[184] He developed service life estimates for seven BGE accounts: (1) Station Equipment; (2) Poles, Towers and Fixtures; (3) Overhead Conductors and Devices; (4) Underground Services; (5) Underground Street Lighting and Signal Systems; (6) Services; and (7) Smart Grid Meters and Modules.

In his analyses, Mr. Garrett compared the Iowa curves used by BGE to the Iowa curves he selected, and he found his selected curves to be a better or closer mathematical fit to the OLT curves, by minimizing the distance between the OLT curves and the Iowa Curves.[185] With regard to the Smart Grid Meters and Modules, Mr. Garrett noted that BGE proposed 10-year average service life spans for its Smart Grid Meters and Smart Grid Meter Modules accounts, and a 15-year service life for its Meter Modules account.[186] He found that, based upon discovery responses from BGE that included recommended service lives for gas accounts, smart meter assets have an estimated service life ranging from 15 to 20 years.[187] While OPC witness Garrett agreed with BGE's conclusion that the assets in question will obtain the longer service lives, he indicated that a 10-year estimated service life was not a more accurate determination.[188] He stated that the data supported a 15-year service life for the BGE accounts.[189] Mr. Garrett stated further that generally, regulators should focus on statistical analyses of a utility's actual retirement data as opposed to a comparable analysis using an industry average; however, he concluded that BGE historical

[183] *Id.*
[184] *Id*. at 14.
[185] *Id.* at 15-27.
[186] *Id.* at 27-28.
[187] *Id*. at 29.
[188] *Id.*
[189] *Id*.

data was insufficient for a statistical analysis, and the Commission should therefore rely more on industry statistics for these accounts.[190]

Mr. Garrett agreed with BGE witness Allis' proposed net salvage rates, calculated under the Maryland present value method, and did not propose any adjustments to Mr. Allis' proposed future net salvage rates.[191] However, Mr. Garrett proposed two adjustments to BGE's calculation of net salvage rates—that the net salvage rates should be calculated on a composite, account-level basis as opposed to the vintage level used by BGE, and that the Commission should use BGE's weighted average rate of return as the discount rate instead of the CARFR.[192] He explained that BGE's calculation of present value net salvage rates on a vintage level increases the annual depreciation accrual by approximately $15 million, compared to his calculations on an account level using the same future net salvage rates and discount rate.[193]

Mr. Garrett proposed that the Commission use BGE's weighted average rate of return as the discount rate in the Maryland present value method.[194] He noted OPC witness Woolridge's proposed rates of return for 2024 to 2026 comprised the discount rate he used in his net salvage rate calculations.[195] He recommended that if the Commission adopted a different weighted rate of return, it should be used as the discount rate under the Maryland Present Value Method.[196] Mr. Garrett mentioned Professor Woolridge's recommended 2024 rate of return of 6.71% should the Commission decide to end BGE's MYP.[197] He

[190] *Id.* at 29-30.
[191] *Id.* at 32.
[192] *Id.*
[193] *Id.* at 33.
[194] *Id.* at 34.
[195] *Id.*
[196] *Id.*
[197] *Id.*

further recommended that regardless of the rate of return used, it should be used as the discount rate.[198]

With regard to the use of the rate of return as the net salvage rate instead of the CARFR, Mr. Garrett explained that an estimated CARFR does not directly impact customer rates, as does the rate of return.[199] He stated that the 4.86% CARFR used by BGE and the 6.71% rate of return (used as the discount rate) he proposed resulted in an $11 million difference in the impact to the annual depreciation accrual, and his proposed use of the rate of return (as a discount rate) could partially offset harmful financial impact to customers.[200]

On rebuttal, BGE witness Allis disagreed with the longer service life estimates rendered by the other witnesses, noting in particular OPC witness Garrett's statements that smart meters typically have 15-20 year service lives, despite the Commission's authorized current 10-year service life estimate.[201] Mr. Allis testified that some utilities have begun replacing smart meters earlier than estimated and company estimates are more pertinent than industry information.[202] Mr. Allis argued that the service life estimates proposed by Staff witness Garren and OPC witness Garrett are unreasonably long for the assets studied and for BGE's current and future operating environment.[203]

Mr. Allis also stated that OPC's proposed longer gas service lives was contradictory to gas industry changes in light of Maryland's Climate Solutions Now Act of 2022 (the

[198] *Id.*
[199] *Id*. at 35.
[200] *Id.*
[201] Allis Rebuttal at 23.
[202] *Id.* at 24.
[203] *Id.* at 11.

"CSNA"), decarbonization efforts, and BGE's current and future operating environment.[204]

He discussed Staff's and BGE's net salvage proposals, using the Maryland Present Value Method with the CARFR based discount rate of 4.86% and calculating net salvage accruals at the vintage level, contrasting it with OPC's use of a higher discount rate, proposed use of the rate of return instead of CARFR, and proposed calculation of net salvage accruals at the composite vintage level.[205] Mr. Allis asserted that OPC witness Garrett's proposal is counter to recent Commission precedent and argued that OPC's concerns about transparency, ease of replication and excessive complexity could have been more reasonably addressed through the traditional straight-line method of net salvage, as used by most regulatory commissions.[206] He noted that Mr. Garrett did not dispute his direct testimony preferring the use of CARFR over the rate of return.[207]

BGE witness Frain objected to Staff and OPC proposals to lengthen the service lives of electric distribution accounts and, pertaining to OPC, the service lives of both gas and electric distribution accounts.[208] He stated that concerns about gas assets being stranded or a decrease in gas throughput were not compatible with depreciation proposals that would increase the service lives of gas distribution assets.[209] He added that similarly, if decarbonization efforts result in the early replacement of electric assets with more powerful infrastructure, then it is not logical to lengthen the service lives of electric

[204] *Id.*
[205] *Id.*
[206] *Id.* at 25.
[207] *Id.* at 29.
[208] Frain Rebuttal at 11-12.
[209] *Id*. at 12.

distribution assets.[210] Mr. Frain asserted that the lengthening of service lives in this context would saddle future customers with costs that current customers should be shouldering instead.[211] Mr. Frain recommended that the Commission reject OPC's discount rate recommendation and authorize BGE's proposed CARFR.[212]

In his surrebuttal testimony, Staff witness Garren focused on Mr. Allis' rebuttal statements regarding what he deemed to be the effects of the CSNA as related to BGE's substation equipment having shorter lives in the future, while Staff and OPC are proposing longer lives.[213] Mr. Garren also pointed to Mr. Allis' rebuttal argument that for the electrification scenario of depreciation proposals, depreciation should be approximately $440 million, and accounts such as substations and overhead conductors should have shorter lives.[214] Mr. Garren questioned the assertions, contending that in his review of the evidence, he saw no mention by Mr. Allis regarding consideration to the CSNA or electrification.[215] Mr. Garren noted that he was not proposing longer service lives or steeper retirement curves, but he was emphasizing that the CSNA impact was more complex than implied in Mr. Allis' rebuttal testimony and should have been a part of a depreciation study.[216]

<u>Commission Decision</u>

The Supreme Court has defined depreciation as "the loss, not restored by current maintenance, which is due to all factors causing the ultimate retirement of the property.

[210] *Id.* at 12-13.
[211] *Id.* at 13.
[212] *Id.* at 14.
[213] Garren Surrebuttal at 3.
[214] *Id.*
[215] *Id.* at 4.
[216] *Id.* at 5.

These factors embrace wear and tear, decay, inadequacy, and obsolescence."[217] The Court further held:

> [T]he company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion.[218]

Historically, net salvage costs were recovered on a straight-line basis in the development of depreciation rates In other words, the depreciation rate would fund the recovery of the asset plus an estimated of necessary retirement costs on an equal basis over the remaining life of the asset.[219] However, in recent years, the Commission has permitted recovery of net salvage costs on a present value basis, such that the utility's depreciation rates reflect the present value of amounts required to fund the retirement of plant investment. In Case No. 9092, for example, the Commission found that "[t]he Present Value Method strikes a balance between the straight line and historical recovery proposals. …[B]ecause future costs are discounted to a 'present value,' today's ratepayers will pay only half their fair share of recovery costs in 'real' dollars rather than the inflated amounts under Straight Line Method." Accordingly, the Commission found that the Present Value Method "strikes an appropriate balance between the interests of current and future ratepayers.[220] The Commission sees no reason to depart from the Present Value Method in the present case.

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[217] *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 167 (1934).
[218] *Id.* at 169.
[219] *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*, Case No. 9481, Order No. 88944 at 62.
[220] *In the Matter of the Application of Potomac Electric Power Company for Authority to Revise Rates and Charges for Electric Service and Certain Rate Design Changes, Case No. 9092,* Order No. 81517 at 31.

The Commission has reviewed the record and finds that the Present Value Method should be adopted for the recovery of removal costs, as it continues to strike an appropriate balance between the interests of current and future ratepayers. Therefore, in this case, the Commission will apply the Present Value Method to BGE's service lives.

The Commission approves a depreciation expense of $149.1 million for BGE's electric plant, as recommended by Staff. The Commission further approves BGE's proposed net salvage rates, calculated under the Maryland Present Value Method, at the proposed 4.86% discount rate, as well as BGE's proposed future net salvage rates.

Additionally, the Commission directs BGE to make the depreciation adjustments to the following accounts: 361–Structures and Improvements – as recommended by BGE; 362–Station Equipment – as recommended by Staff; 364–Poles, Towers and Fixtures – as recommended by Staff; 365–Overhead Conductors and Devices – as recommended by Staff; 367–Underground Conductors and Devices, as recommended by Staff; 369.2–Underground Service – as recommended by Staff; 373.20–Underground Street Lighting and Signal Systems – as recommended by Staff; 380.00–Gas Services – as recommended by BGE; 381.01–Gas Smart Grid Meters — as recommended by BGB; and 381.11–Gas Smart Grid Meters Modules – as recommended by BGE .

I. Electric Specific Adjustments

1. 4kV Conversion

BGE witness Vahos testified that BGE's 4kV conversion program replaces 4kV infrastructure with a more resilient 13kV infrastructure. He asserted that the program supports broader solar and EV adoption, installation of EV chargers, and installation of fiber that supports critical grid communications infrastructure and will provide connectivity for underserved communities.[221] BGE witness Ajit Apte testified that BGE is investing $14 million to $18.2 million in annual capital to retire its legacy 4kV system equipment.[222] He stated that the 4kV conversion project will remove the remaining 4kV islands from BGE's system to improve reliability and increase capacity. He asserted that the substations that are part of the 4kV system are some of the oldest owned by BGE.

Staff witness Austin testified that BGE's 4kV conversion program in MYP 2 is part of a decades-long program by BGE to retire its legacy 4kV system equipment and convert it to modern 13kV standards.[223] He stated that BGE has approximately 40,000 customers remaining on 4kV that it expects to convert to 13kV by December 31, 2029.[224] Mr. Austin testified that when customers on 4kV are converted to the 13kV system, they typically experience a small reliability improvement as a result of having new infrastructure service their homes and businesses. Mr. Austin testified that Staff has supported BGE's 4kV to 13kV conversion program in the past and continues to support the program. Nevertheless, he asserted that Staff does not support the increase in budget that BGE has proposed in this MYP for its 4kV conversion program.[225]

Mr. Austin stated that when BGE presented its System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") proposals in Case No. 9353 in 2022, its proposed expenditures for the projects in its 4kV conversion program for the years 2024-2026 were forecast to be approximately $43.8 million.[226] Nevertheless, Mr. Austin observed that BGE's proposed expenditures for the

[221] Vahos Direct at 19-20.
[222] Apte Direct at 18.
[223] Austin Direct at 46-47.
[224] *Id*. at 47, citing BGE response to Staff DR No. 61-01(a).
[225] Austin Direct at 24.
[226] *Id*. at 47, citing Maillog No. 239395 at 33.

14 4kV conversion projects proposed for the 2024-2026 period of this MYP have risen to approximately $49.3 million.[227] With the addition by BGE of the Monument Street Substation Feeder upgrade project, which was included in BGE's Capacity Expansion category, BGE's expenditures on 4kV conversions rise to $51.7 million for the MYP 2 period. Mr. Austin testified that BGE was not able to demonstrate in its rate application any material reliability benefits for the increased expenditures on its 4kV conversion program in this MYP.[228] Accordingly, Mr. Austin recommended disallowance of the additional $7.9 million BGE has budgeted for the 4kV conversion program since Case No. 9353 in 2022.[229] Mr. Austin further recommended that during the reconciliation period of MYP 2, the Commission make disallowances for any significant variance of expenditures above the proposed costs of $43.8 million that were made in Case No. 9353 in 2022.

OPC witness Stephens asserted that the level of 4kV circuit conversions BGE has proposed within the MYP 2 period is excessive.[230] Mr. Stephens testified that conversion of a 4kV circuit to 13kV can only be justified if the circuit is overloaded or forecasted to be overloaded in the near future, arguing that: "The difference in reliability performance between 4kV circuits and 13kV circuits is simply too small to make 4kV circuit conversions cost-effective."[231] Mr. Stephens argued that the reliability value of a 4kV circuit conversion of $253,000 is eclipsed by the average cost to convert the 4kV circuits in BGE's first MYP of $3.375 million each.[232] Accordingly, Mr. Stephens recommended that the Commission reduce BGE's 4kV conversion capital spending budget by one-half.

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[227] Austin Direct at 47-48, citing BGE witness Apte Direct Testimony, Exhibit AA-1E, at 17-22 and 28-33.
[228] Austin Direct at 47-48.
[229] *Id*. at 49.
[230] Alvarez-Stephens Direct at 78.
[231] *Id*. at 78-79.
[232] *Id*. at 80.

Mr. Stephens calculated that this reduction would allow BGE to complete the remaining 40 4kV circuits and seven 4kV substations within the next twelve years, by 2035, rather than in the next six years.[233]

In her rebuttal testimony, BGE witness Wright testified that aging infrastructure and improved restoration capability, rather than increasing capacity, are the main drivers for 4kV conversion.[234] She asserted that 4kV systems are outdated and lead to poor reliability performance due to age and limited restoration capability.[235] Ms. Wright argued that the conversion of 4kV systems to 13kV systems allows for significantly improved restoration times due to the ability of 13kV systems to incorporate automated sectionalizing and restoration and remote distribution monitoring and sensors.[236] Ms. Wright testified that 4kV system conversions result in substantial reliability improvements—cutting outage frequency and customer interruption durations by more than half.[237] Ms. Wright opposed OPC's recommendation to cut the budget by 50% and lengthen the timeline for conversion. She stated that the average age of the remaining substations to be converted is 68 years, and that delaying the remaining conversion schedule to 12 years would increase the average age of the remaining 4kV equipment and infrastructure, thereby increasing risk exposure for the remaining 4kV customers and further jeopardizing their service reliability.[238]

Ms. Wright testified that the remaining portion of BGE's 4kV system is largely located in Baltimore City. She also stated that Baltimore suffers from historical racial

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[233] *Id*.
[234] Wright Rebuttal at 18.
[235] *Id*. at 18-19.
[236] For example, Ms. Wright testified that when a fault occurs on a 4kV feeder mainline, it will often take out the entire feeder back to the breaker in the substation and require considerable time and resources to restore service. Wright Rebuttal at 19.
[237] Wright Rebuttal at 19-20.
[238] *Id*. at 19.

inequities leading to significant economic disadvantages. She testified that over half of Baltimore residents live below 200% of the federal poverty line, with more than half of those residents living in deep poverty, at or below 50% of the federal poverty line.[239] Ms. Wright estimated that accelerating the modernization of the remaining 4kV electric infrastructure in Baltimore would reduce system incidents by an estimated 50%, benefiting over 14,000 customers in Baltimore City, including eight communities categorized as disadvantaged.[240]

In response to Staff's concerns about increasing budgets, Ms. Wright asserted that BGE's forecasted budgets over the MYP 2024-2026 period were prepared almost a year after those prepared for Case No. 9353. She also cited BGE witness Vahos, who testified that several factors could cause actual spend to diverge from the Company's budgets, including inflation, supply chain realities, efficiencies BGE is able to achieve, changing business needs, new regulations, and field conditions.[241]

In his surrebuttal testimony, Mr. Stephens stated that irrespective of the reliability benefits alleged by Ms. Wright, the 4kV conversion costs outweigh the financial value to customers of reliability improvements by more than 10 to 1.[242] Mr. Stephens further asserted that although failure risk does increase with age, the incremental risk is very small.

Commission Decision

The Commission finds that BGE's program to continue upgrading its existing 4kV infrastructure to 13kV will improve the restoration capability of BGE's distribution system.

[239] *Id*. at 21.
[240] *Id*. at 21-22.
[241] *Id*. at 20, citing Vahos Direct at 20.
[242] Alvarez-Stephens Surrebuttal at 63.

In particular, the program will support the installation of applications such as automated sectionalizing and restoration, remote distribution monitoring and sensors, and advanced capacitor monitoring, which should significantly improve reliability.[243]

BGE's 4kV conversion program will also produce certain O&M savings. For example, 4kV conversions will enable future O&M savings ranging from approximately $25,000 to $85,000 annually per substation, compared to current forecasted O&M.[244] Likewise, BGE stated that removing a 4kV oil switch should result in a savings of approximately $19,000 over eight years. Staff witness Austin testified that there may be additional O&M savings from reduced outages that are not able to be quantified as part of replacing the old 4kV distribution infrastructure with new 13kV distribution infrastructure.

Because the number of customers impacted by BGE's replacement of its remaining 4kV infrastructure is small, the reliability impact of the projects on overall system reliability is not great.[245] Nevertheless, the impact to the customers being upgraded will be more significant. During the evidentiary hearing, BGE witness Wright testified that the remaining portion of BGE's 4kV system is largely located in Baltimore City, which suffers from historical racial inequities leading to significant economic disadvantages.[246] Those disadvantaged communities frequently lack the resources required to cope with prolonged power outages, and should not be left out, or face unnecessary delays with regard to BGE's 4kV conversion program. The Commission finds that OPC's proposal to reduce 4kV conversion spend by 50% would impose excessive delay on the 4kV conversion program,

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[243] *See* Wright Rebuttal at 19-20.
[244] Austin Direct at 49, citing BGE response to Staff DR No. 39-11.
[245] *See* Staff witness Austin, stating that "the reliability impact of these projects on overall system reliability is not material enough to be shown on a SAIFI waterfall chart." Austin Direct at 48, citing BGE's Proposed Reliability Standards for 2024 – 2027, Maillog No. 239395 (March 01, 2022) at 26.
[246] Hr'g. Tr. at 680 (Wright); BGE Initial Brief at 32.

to the detriment of those disadvantaged communities.[247] In contrast, the Commission finds that Staff's proposal to limit 4kV conversion spend to the $43.8 million budget BGE proposed in 2022 in Case No. 9353 strikes an appropriate balance between the need to continue 4kV conversion, and the goal of minimizing burden on ratepayers. Therefore, the Commission approves the budget for the 4kV conversion program as proposed by Staff.

2. Planned Cable Replacement Program

BGE witness Apte testified that planned cable replacement is the primary driver of spend in the category of aging infrastructure for the period 2021-2023, accounting for $10.1 to $15 million of annual spend.[248] Mr. Apte stated that the purpose of the cable replacement program is to improve the customer experience by "strategically and proactively replacing BGE's aging distribution cable, thereby improving the operation and reliability of the underground system while reducing maintenance spending."[249] Mr. Apte asserted that BGE prioritizes cables for replacement based on factors that include the number of historical failures, frequency of failures, and the number of customers affected. Mr. Apte contended that by replacing BGE's most fault-prone cables, the Company will reduce its SAIFI, SAIDI, and CEMI for the benefit of our customers, and avoid costly repeat repairs that would cost customers more in the long run.[250] BGE witness Wright testified that

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[247] BGE stated that it applied for an IIJA grant in support of the Company's "Advancing a Just and Equitable Transformation for a Resilient and Cleaner Grid of the Future in Baltimore" ("JET") Project, which is designed to improve grid reliability for disadvantaged communities, including replacing poor performing 4kV equipment. *See* BGE Initial Brief at 32, n. 135.
[248] Apte Direct at 17.
[249] *Id*.
[250] *Id*. at 17-18.

BGE's proposed budget for 2024 envisions replacing 45-55 miles of cables in 2024 and approximately 75-85 miles per year in 2025 and 2026.[251]

Staff witness Austin testified that BGE currently replaces 47.6 miles annually under its cable replacement program, which is only slightly above the industry average of 47.5 miles.[252] Mr. Austin stated that when BGE presented its SAIFI and SAIDI proposals in 2022, its proposed expenditures under the present planned cable replacement program for the years 2024-2026 were forecast to be approximately $46.2 million per year.[253] However, Mr. Austin asserted that in this MYP, BGE has proposed to ramp up its cable replacement rate to achieve up to 45-55 miles of replacement in 2024 and 75-85 miles per year in 2025 and 2026 at a cost of approximately $84.4 million.[254]

Mr. Austin agreed with BGE witness Apte that BGE's cable replacement program is vital to ensuring that customer reliability continues to be maintained and to ensuring a resilient electric system.[255] Nevertheless, Mr. Austin contended that BGE's proposed acceleration of its planned cable replacement program could have been a candidate for IIJA funding under the DOE GRIP, since the goal of the DOE GRIP is to enhance grid flexibility and improve the resilience of the power system. Based on discovery responses provided by BGE, Mr. Austin testified that there would be no appreciable difference in BGE's SAIFI scores whether BGE continues the current cable replacement schedule, or if it pursues the proposed accelerated cable replacement schedule.[256] Therefore, Mr. Austin advocated

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[251] Wright Supplemental at 4. During the evidentiary hearing, Ms. Wright adopted the Direct Testimony of BGE witness Apte, who moved to another role in BGE. Hr'g. Tr. at 91 and 637 (Wright).
[252] Austin Direct at 50, Apte Direct at 24.
[253] Austin Direct at 50, Maillog No. 239395 at 33.
[254] Austin Direct at 50, Apte Direct at 26.
[255] Austin Direct at 51.
[256] *Id*. at 51-52.

against BGE's proposed accelerated cable replacement schedule and recommended instead that the Commission disallow the $38.2 million that the accelerated schedule would cost.

OPC witness Stephens testified that BGE has proposed to spend $89.6 million replacing underground cable in MYP 2, which is more than double what it spent in its first MYP.[257] He argued that cable life varies widely based on many factors, but that premature replacement imposes a needless cost on ratepayers.[258] Mr. Stephens testified that most utilities use a "three strikes and replace" strategy, where they replace cable that has failed three times. He stated that BGE follows this policy and budgets for cable replacement that has failed at least three times under the category of "corrective maintenance." However, Mr. Stephens stated that pursuant to its cable replacement program, BGE replaces a targeted number of miles of cable regardless of faults, including some segments of cable that have no strikes and may be perfectly sound.[259] In order to limit costs to ratepayers, Mr. Stephens recommended that the cable replacement budget in MYP 2 be limited to the average level of spending in 2021 and 2022, which is $12.25 million, adjusted for inflation.[260]

BGE witness Wright disagreed with OPC witness Stephens' characterization of the cable replacement program as replacing cable that is "perfectly sound."[261] Ms. Wright also denied that BGE has a 'three strikes and replace' policy for cable replacement.[262] Instead,

[257] Alvarez-Stephens Direct at 81.
[258] *Id*. Mr. Stephens stated that variables that affect cable life include installation practices, construction methods, soil types, soil moisture levels, and tree root growth, among others.
[259] Alvarez-Stephens Direct at 81-82.
[260] *Id*. at 84.
[261] Wright Rebuttal at 23, citing Alvarez-Stephens Direct at 81.
[262] Wight Rebuttal at 24. Ms. Wright stated that BGE's Reliability & Maintenance Planning team does track the number of cable faults and BGE makes a replacement decision based on that number and other variables. Wright Rebuttal at 24-25.

Ms. Wright asserted that BGE's program proactively identifies poorer performing cable that is susceptible to higher fault rates, as well as a method of tracking fault rates of cable segments that meet the criteria for replacement.[263] Ms. Wright testified that BGE's electric distribution system contains approximately 1,900 miles of problematic cable that the Company is prioritizing for replacement, composed of six cable types that have a higher failure rate than the industry average.[264]

Ms. Wright further asserted that Staff's analysis of the benefits of the cable replacement program was erroneous because of inadvertently flawed data that BGE sent to Staff in response to a data request.[265] With regard to Staff's concern about IIJA funding, Ms. Wright stated that BGE applied for an IIJA GRIP Program grant with a project focused on greater resiliency and clean energy for disadvantaged communities in Baltimore, including upgrades to the 4kV distribution infrastructure, solar, storage, and EV charging stations. Ms. Wright stated that BGE did not apply for IIJA funding support for the cable replacement project because the work included in it is focused on benefits to overall BGE customers and not focused solely on disadvantaged communities, which is a primary focus of the GRIP Program grant.[266]

Ms. Wright stated that BGE reduced its cable replacement budget during MYP 1 in response to Commission Order No. 89678, but that the Company's reduced cable replacement resulted in "concerning trends in primary faults increasing," which informed BGE's decision to augment the cable replacement program budget in 2023 from $11

[263] Wright Rebuttal at 23.
[264] *Id*. at 25-26. BGE witness Apte asserted that the six cable types with a high rate of failure were largely installed in the 1960s and 1970s and include XLP Non-Jacketed, High Molecular Weight and Paper-Insulated and Lead-Covered cables. Apte Direct at 19.
[265] Wright Rebuttal at 23, referencing BGE response to Staff DR14-01.
[266] *Id*. at 31.

million to $15 million in an effort to curb this upward fault trend.[267] Ms. Wright testified that BGE's cable fault rate of 7.3 faults per 100 miles is significantly higher than the industry average of 5.3 faults per 100 miles, and that BGE must take steps to align itself with the industry average.[268] Ms. Wright testified that BGE would need to replace at least 51 miles per year to avoid increases in total system faults and losing ground relative to the industry average.

In his surrebuttal testimony, Staff witness Austin stated that BGE filed a revised discovery response to a Staff data request that changed Mr. Austin's analysis regarding the efficacy of BGE's cable replacement program. Specifically, he stated that BGE's program would yield SAIFI improvements in this MYP that would be greater than the benefits of the cable replacement program it proposed in Case No. 9353.[269]

Mr. Austin employed a benefit-cost tool developed by the U.S. Department of Energy ("DOE")—the Interruption Cost Estimate ("ICE")—to estimate the overall benefits associated with the proposed reliability improvements. Using the ICE analysis, Mr. Austin determined that BGE's proposed cable replacement program—including the additional $38.4 million it would cost to implement the program it is proposing in this MYP—would provide a favorable reliability benefits to cost ratio of 1.21.[270] Mr. Austin therefore recommended that BGE be authorized to fully recover the approximately $84.6 million that will be required to support this program, subject to future reconciliation where any

[267] *Id*. at 26-28.
[268] *Id*. at 29.
[269] Austin Surrebuttal at 6-7.
[270] *Id*. at 8-9.

significant variance above this proposed amount without satisfactory justification would be disallowed.[271]

In his surrebuttal testimony, OPC witness Stephens argued that the increase in BGE's cable fault rate "is almost imperceptible and may not be statistically significant."[272] Mr. Stephens further stated that BGE has not demonstrated that the value to customers of the reliability improvements secured exceed the incremental costs of the program.

Commission Decision

The Commission authorizes BGE's planned cable replacement program and denies OPC's proposed adjustments as described herein. BGE provided testimony that its planned cable replacement program will improve the operation and reliability of the Company's underground system to help ensure the maintenance of customer reliability and a resilient electric system. BGE's plan to augment its cable replacement rate follows what BGE portrays as concerning trends in primary fault increases. Specifically, BGE witness Wright highlighted BGE's current cable fault rate of 7.3 faults per 100 miles, which is significantly higher than the industry average of 5.3 faults per 100 miles.[273] BGE witness Apte also presented testimony that the program would reduce BGE's SAIFI, SAIDI, and CEMI, and avoid repeat repairs that would cost customers more in the long run.[274]

OPC challenged BGE's program based on the high costs of the program relative to its purported benefits. Mr. Stephens argued that BGE replaces a targeted number of miles of cable regardless of faults, and may therefore replace cable that is perfectly sound and

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[271] *Id*. at 9.
[272] Alvarez-Stephens Surrebuttal at 66.
[273] Wright Rebuttal at 29.
[274] Apte Direct at 17-18.

has remaining useful life.[275] He also asserted that BGE has not demonstrated that the reliability improvements of the program exceed the incremental costs.[276] However, BGE presented evidence that it bases its cable replacement on several factors that target aging distribution cable that has a high likelihood of failure, including the number of historical failures, frequency of failures, and the number of customers affected.[277]

Regarding benefit-cost analysis, Staff witness Austin testified that he employed DOE's ICE analysis to determine that BGE's cable replacement program would provide a favorable reliability benefit to cost ratio of 1.21.[278] He therefore recommended that BGE be authorized to fully recover the approximately $84.6 million that will be required to support this program.

The Commission in its previous decision found that the Company's planned cable replacement program was an important element in BGE's plan to comply with mandatory reliability standards, and based on this record the Commission still believes this is an important part of BGE's reliability programs.[279] Nevertheless, the Commission must balance improving reliability against affordability to ratepayers and is not yet convinced an acceleration in the program is warranted. Therefore, the Commission will reduce the rate of spending to balance financial impacts to ratepayers.[280] The Commission will accomplish this by setting BGE's budget for years 2025 and 2026 based on its projected spend in 2024. BGE witness Wright testified the level of spend in 2024 is required to comply with current reliability requirements and the Commission will accordingly permit

[275] Alvarez-Stephens Direct at 81-82.
[276] Alvarez-Stephens Surrebuttal at 66.
[277] Apte Direct at 17-18.
[278] Austin Surrebuttal at 8-9.
[279] Order No. 89678, Case No. 9645 at 97-98.
[280] *Id*. at 101-102.

this level of spend based on the record.[281] The Company is free to propose acceleration of its cable replacement program in Case No. 9353. As with all of the programs proposed for BGE's MYP period, this authorization is not a prejudgment of prudency. That review will occur during reconciliation.

3. Diverse Routing Program

BGE witness Apte testified that when supply circuits to BGE distribution substations are located within a common right of way, a common failure point is created.[282] He stated that a failure within this common right of way could result in the total loss of substation supply. He further stated that there is a low probability that these types of failure will occur, but—if a failure occurs—it would have a large reliability impact due to the number of customers impacted.[283] Mr. Apte asserted that BGE's diverse routing project evaluates areas on the BGE system with common right of way and plans cost effective solutions to reduce common right of way exposure.

Staff witness Austin testified that when BGE presented its SAIDI and SAIFI proposals in 2022, its proposed expenditures for its diverse routing program was $3.2 million for the years 2024-2026.[284] But in this MYP, Mr. Austin stated that BGE has proposed expenditures for the diverse routing program of approximately $4.1 million. Mr. Austin evaluated the SAIFI improvement that would be realized from this program for the years 2024-2026, and concluded that BGE's ratepayers would see no reliability benefit from the additional $900,000 in spending that BGE proposed for this program in this MYP

[281] Wright Rebuttal at 29-30.
[282] Apte Direct at Exhibit AA-1E, p. 20.
[283] *Id*.
[284] Austin Direct at 56, citing BGE Response to Staff DR 14-02(a).

period, and recommended disallowance of this additional spending.[285] Mr. Austin also recommended that during the reconciliation period of this MYP, any significant variance of expenditures above the $3.2 million proposed in Case No. 9353 in 2022 be considered for disallowance.

BGE witness Wright stated in her rebuttal testimony that BGE's proposed funding for this program is targeted at opportunities to install 34kV overhead reclosers to reconfigure the subtransmission system to restore supply to downstream substations after a single right of way contingency.[286] She asserted that the 2024 and 2025 funding can address one to two at-risk substations per year, but that increased funding in 2026 will allow BGE to address additional substations, to further reduce the 49 at-risk substations in BGE's service territory.[287]

Commission Decision

The Commission accepts Staff witness Austin's adjustment to BGE's diverse routing program. Mr. Austin's analysis demonstrated no additional reliability benefits from BGE's additional proposed expenditures on its diverse routing program.[288] Accordingly, the spending on BGE's program should be limited to the original budget it proposed in 2022 of approximately $3.2 million.

4. Common Trench Enhancement System Program

Staff witness Clementson testified that BGE's Common Trench Enhancement System ("CTES") program is designed to rework its gas and electric infrastructure for

[285] Austin Direct at 57.
[286] Wright Rebuttal at 51.
[287] *Id*. at 51-52.
[288] Austin Direct at 56-57; Austin Surrebuttal at 9-10.

various locations, due to the risk that these common trench facilities may have been installed inappropriately close to one another.[289] Mr. Clementson stated that the CTES program developed as a result of the August 25, 2019 explosion that occurred in an office building at Stanford Boulevard in Columbia, Maryland after a gas leak was detected.

Mr. Clementson testified that the Commission's Engineering Division conducted an investigation of the Stanford Boulevard incident and determined that BGE's electric service to the building had faulted, and that heat generated from the fault caused the gas pipe to melt in several places, allowing gas to escape and migrate up through cracks in the building's parking lot.[290] The investigation further revealed that the gas collected and was ignited from an unknown ignition source, which resulted in the explosion and destruction of the building.[291] Mr. Clementson stated that BGE Projects 68155 (electric) and 68156 (gas) constitute BGE's remediation plan to mitigate the risk of future similar events by ensuring that the physical separation distances between utilities in common trenches is adequate.[292] Mr. Clementson stated that BGE has 253 similar locations that it intends to remediate.[293]

Mr. Clementson observed that as a result of the Engineering Division's findings, the Commission docketed Case No. 9653, and issued Order No. 89685 on January 7, 2021.[294] Among other things, that order accepted BGE's proposed remediation plan, required that BGE track all expenditures related to that plan, and held that the Commission

[289] Clementson Direct at 5.
[290] *Id*. at 5-6.
[291] The explosion occurred early on a Sunday morning when the building was unoccupied, so there were no injuries reported. Clementson Direct at 6.
[292] Clementson Direct at 6.
[293] *Id*. at 9.
[294] Case No. 9653, *Investigation of Baltimore Gas and Electric Company Regarding a Building Explosion and Fire in Columbia, Maryland on August 25, 2019*, Order No. 89685 (Jan. 7, 2021).

would conduct a prudency review regarding all expenditures related to BGE's remediation plan in a future proceeding.[295]

For purposes of this MYP, Mr. Clementson recommended that the Commission disallow BGE recovery of certain expenses related to the CTES program.[296] Specifically, he argued, "I am recommending that BGE not be allowed to recover its expenses related to Project 68156: Common Trench Enhancement Gas for CY2021 and CY2022 because ratepayers should not be held responsible for the expenses incurred by BGE for rework due to the risk that these common trench facilities may not have been correctly installed originally."[297] Additionally, because BGE was not able to provide the percentages of its CTES program work that has been completed on gas and electric services that have exceeded their useful life, Mr. Clementson stated that he is recommending full rather than partial disallowance of actual expenses for CY2021 and CY2022 for Project 68156. Staff witness Dererie recommended disallowance of Project 68155 - Common Trench Enhancement-Electric Distribution Program costs in 2021 and 2022 based on the conclusions reached by Mr. Clementson.[298]

Staff witness Austin testified that BGE forecasts approximately $4.2 million to be spent on Project 68155 (Common Trench Enhancement–Electric) during this MYP period.[299] For the same reasons articulated by Mr. Clementson, Mr. Austin recommended a full disallowance of the $4.2 million that BGE is proposing to spend on the electric side

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[295] The Commission also assessed a civil penalty against BGE in the amount of $437,294. Order No. 89685 at 10-11.
[296] Clementson Direct at 9. Mr. Clementson did not testify regarding the electric portion of BGE's CTES program.
[297] Clementson Direct at 9.
[298] Dererie Direct at 35 and 41.
[299] Austin Direct at 72.

of the CTES program.[300] Staff witness Anyinam also opposed the recovery of Project 68155 (Common Trench Enhancement–Gas), agreeing that ratepayers should not pay for rework of facilities that may not have been installed correctly.[301]

In her rebuttal testimony, BGE witness Wright opposed Staff's recommendation to disallow CTES program costs in the 2024-2026 MYP rates.[302] Ms. Wright argued that Staff mischaracterized the program as enhancements to re-work incorrectly installed equipment. Ms. Wright asserted that Staff previously agreed with BGE's proposed plan to conduct the work in the CTES program, and that BGE performed the work only after the Commission accepted the program in Order No. 89685.[303] Ms. Wright further testified that the work was conducted to bring the common trenches at issue up to BGE's current construction standards, from the older, outmoded 1997 standards that applied when they were originally installed.[304] She stated that the costs were also incurred to add additional, more modern, safety enhancements to these common trenches that were not available when they were first constructed. Ms. Wright therefore disputed any characterization that the common trench facilities were incorrectly installed originally.[305] Finally, Ms. Wright asserted that BGE is not seeking cost recovery of its remediation efforts in connection with the Stanford Boulevard installation.

BGE witness White testified that the Company's plan for the CTES work was supported by Staff, submitted to the Commission, and found to be acceptable, including

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[300] *Id*. at 73.
[301] Anyinam Direct at 30.
[302] Wright Rebuttal at 31 and 35.
[303] *Id*. at 34, citing *Investigation of Baltimore Gas and Electric Co*., Case No. 9653, Order No. 89685 at para. 20 (Md. PSC, Jan. 7, 2021).
[304] Wright Rebuttal at 34.
[305] *Id*. at 35.

the finding that the proposed "safety upgrades should be performed."[306] Ms. White further asserted that the common trench project enhances safety, by bringing gas services in certain common trench installations up to current standards by installing curb valves and/or excess flow valves, but does not replace any gas services. Ms. White argued that Staff's premise that BGE is replacing assets prior to the end of their service life as a result of potential incorrect installations was incorrect.[307] Similarly, BGE witness Dickens argued that although BGE's common trench program relocates lines in certain circumstances, the majority of the work under these projects is adding new infrastructure that will bring the installations up to current standards.[308] Mr. Dickens asserted that the common trench work should not be characterized as a correction or rework as Staff suggested, but rather an upgrade.[309]

In response to Staff's concerns about the documentation of CTES program costs, BGE witness Frain supported Ms. Wright's rebuttal, but provided an alternative value if the Commission believes an adjustment is warranted. These revised values are premised upon the arguments propounded by witnesses Wright and White that Staff's adjustment removed costs unrelated to the principles Staff was trying to enforce. The three groupings of costs that BGE believes are recoverable under Staff's logic are: (1) costs associated with conduit sealing, because this is new work that enhances the safety, reliability, and resilience of the system; (2) costs associated with Common Trench gas work, because the flow valves installed are incremental system additions that also enhance the safety, reliability, and

[306] White Rebuttal at 107-108, citing Order No. 89685, Case No. 9653, at 8.
[307] White Rebuttal at 108.
[308] Dickens Rebuttal at 26.
[309] *Id*. at 27.

resilience of the system; and (3) costs associated with cable relocation if that work is supporting the replacement of existing cable that is nearing or at the end of its useful life.[310] Under these assumptions BGE witness Frain argues that no gas costs should be disallowed and Staff's disallowance for electric costs should be revised as follows.

Table 3
BGE proposed revision to Staff Disallowance ($000,000)

	2021	2022	2023	2024	2025	2026
Electric Project 68155	$7.0	$1.2	$0.3	$0.3	$0.3	$0.3

In his surrebuttal testimony, Mr. Clementson reversed his recommendation that the actual expenses for BGE's Project 68156 for CY 2021 and CY2022 be disallowed.[311] After reviewing Ms. Wright's testimony, he stated that Project 68156 brings gas services in common trench installations up to current construction standards with safety enhancements by installing excess flow valves and curb valves to enhance safety.[312] Mr. Clementson asserted that at the time of the original installation (before 2001), excess flow valves and curb valves were not required. Additionally, Mr. Clementson stated that when he drafted his direct testimony, he was under the misunderstanding that BGE's Project 68156 involved the installation of new gas services. Given that the Company's Common Trench Enhancement Program only involves the installation of excess flow valves and curb valves to enhance safety, and does not relocate or replace gas service assets, Mr. Clementson recommended that the Company be allowed to fully recover its costs related to the gas

[310] Frain Rebuttal at 17-18.
[311] Clementson Surrebuttal at 2.
[312] *Id*. at 2-3.

portion of the Company's Common Trench Enhancement Program. Staff witness Anyinam revised his recommendation for the common trench enhancement program for gas during the MYP period for the reasons articulated in Mr. Clementson's testimony.[313]

Ms. Dererie, in surrebuttal testimony, changed her recommendation to reflect BGE witness Frain's revised estimation of costs in rebuttal testimony to disallow $7 million in 2021 and $1.2 million in 2022.[314]

In his surrebuttal testimony, Mr. Austin also changed his recommendation from his direct testimony. After reviewing Mr. Frain's testimony addressing common trench costs, Mr. Austin stated that he accepted the Company's analysis and rescinded his previous recommendation to fully disallow the $4.2 million BGE proposed to spend on the common trench program in this MYP period.[315] Therefore, Mr. Austin recommended that BGE be disallowed only $900,000 of the $4.2 million it initially proposed to spend on its CTES – Electric program for the MYP 2 period.

Commission Decision

The Commission accepts Staff's revised recommendation to only disallow some costs associated with Electric Project 68155 (Common Trench Enhancement Program - Electric) in reconciliation and in the MYP. The CTES program was conducted to bring the common trenches at issue up to BGE's current construction standards, and to add additional safety enhancements that were not available when they were first constructed. The August 25, 2019, explosion at Stanford Boulevard demonstrated the importance and the urgency of BGE's program to bring the identified common trenches up to BGE's current

[313] Anyinam Surrebuttal at 8.
[314] Dererie Surrebuttal at 4.
[315] Austin Surrebuttal at 11-12.

construction standards. With regard to the Stanford Boulevard incident, the Commission's Engineering Division found that the proximity of BGE electric facilities to its gas pipe caused the gas pipe to melt in multiple locations when the electric service faulted, thereby allowing gas to escape and lead to an explosion. BGE's program to mitigate the risk of future similar events by ensuring an adequate physical separation between electric and gas utilities is vital to public safety.

BGE witness Wright testified that the CTES work was conducted to bring the common trenches up to BGE's current construction standards, from the older, outmoded 1997 standards that applied when they were originally installed.[316] Staff witness Clementson acknowledged that the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") federal pipeline safety regulations governing the installation of excess flow valves and curb valves did not go into effect until December 4, 2009.[317] Therefore, BGE is not incurring the CTES expenses to remedy common trench facilities that were incorrectly installed originally, but rather to add modern safety enhancements to these common trenches that were not available (or required) when they were first constructed. Moreover, Ms. Wright confirmed through her testimony that BGE is not seeking cost recovery of its remediation efforts in connection with the Stanford Boulevard installation. Accordingly, the Commission finds that any disallowance for imprudence would be unwarranted. The Commission finds; however, that some disallowance is appropriate for 2021 and 2022 electric costs as these costs are driven by a need to remediate electrical equipment location due to some previously misinstalled equipment. The

[316] Wright Rebuttal at 34.
[317] Clementson Surrebuttal at 3.

Commission concludes that the revised disallowance developed by BGE witness Frain, and endorsed by Staff witness Dererie, strikes the appropriate balance by focusing disallowance on plant that still has a useful life while allowing BGE to recover costs for new work and replacement of assets near or at the end of their useful life.

Regarding the MYP 2 expenditures, Staff witness Anyinam rescinded his recommendation to disallow any CTES program costs related to BGE's gas system. Regarding the electric system, Staff's remaining concern related to BGE's previous inability to provide the percentages of its CTES program work that has been completed on gas and electric services that have exceeded their useful life. However, BGE witness Frain provided that evidence in his rebuttal testimony—documenting \$3.3 million of expenditures through the MYP 2 period. Given that BGE sought \$4.2 million for the CTES-Electric program, Mr. Austin revised his recommendation to disallow only \$900,000 of the \$4.2 million originally requested for the MYP 2 period. The Commission accepts Staff's recommendation.

Finally, the Commission observes that the CTES program—which requires the reworking of BGE's gas and electric infrastructure to mitigate the risk that common trench electric and gas facilities may have been installed inappropriately close to one another—involves both the electric and gas distribution systems. The Commission finds that it would be inappropriate to allocate these costs to just one type of ratepayer—electric or gas. Accordingly, the Commission directs that BGE allocate these costs evenly between gas and electric customers.

5. Resilience Investment Plan

BGE witness Apte testified that Maryland has passed laws that set some of the most ambitious greenhouse gas ("GHG") reduction goals in the country, which will require taking steps to significantly electrify the State's transportation and building sectors.[318] As a result, Mr. Apte asserted that BGE's customers will become even more reliant on the electric grid as their primary source of energy for heating and cooling their homes and powering their vehicles. Additionally, Mr. Apte stated that climate change is expected to continue increasing the frequency and intensity of storms, but that BGE prepared its resilience investment plan to make its grid more reliable and resilient.

Mr. Apte testified that a resilient electric system is better able to remain operational through natural and man-made stressors, and if service is interrupted, it can be restored more quickly.[319] An additional advantage is that a more resilient grid will minimize customer costs resulting from outages. Mr. Apte asserted that customers have become increasingly dependent on uninterrupted electric service, including for medical equipment, charging telephones, using computers for home, educational and work purposes, and for a growing number of people, charging their electric vehicles.[320]

Mr. Apte stated that BGE hired a consultant, 1898 & Co. ("1898"), the advisory and technology consulting arm of Burns & McDonnell, to evaluate BGE's electric distribution system and make recommendations on how best to enhance resiliency.[321] Mr. Apte stated that 1898 analyzed the BGE system and issued a report that provides a

[318] Apte Direct at 30.
[319] *Id*. at 32.
[320] *Id*. at 33.
[321] *Id*. at 22.

summary of potential projects to improve the resiliency of BGE's system; BGE is evaluating this summary to determine which projects are technically feasible and will provide the best benefits to customers for the 2024-2026 period.[322]

Mr. Apte stated that 1898 provided a summary of the types of projects that it recommends implementing with a proposed $109 million spend across years 2024-2026, and that BGE has evaluated the recommendations and concurs with them.[323] 1898's recommendation for the $109 million initial resilience investment plan prioritizes three major types of projects: (i) distribution feeder hardening; (ii) lateral undergrounding; and (iii) sub-transmission rebuild. With regard to distribution feeder hardening, BGE intends to strengthen infrastructure on main lines through stronger poles and crossarms, overhead installed covered conductors, or undergrounding overhead conductors.[324] For the lateral undergrounding work, BGE plans to convert overhead lateral feeders and infrastructure to underground. For the sub-transmission rebuild, BGE intends to harden the supply to sub-transmission substations where weaknesses have been identified.[325] In this MYP, BGE is proposing to expend $109 million on 47 distribution feeder hardening projects, 59 lateral undergrounding projects and one sub-transmission rebuild project.[326]

Staff witness Austin testified that BGE's resilience investment plan is intended to address "events that may or may not occur or events that have varying probabilities of occurring, and where the benefits may not be immediately obvious to ratepayers."[327] Mr. Austin stated that the major difference between this resilience plan and reliability projects

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[322] *Id*. at 36.
[323] *Id*. at 39.
[324] *Id*. at 40.
[325] *Id*. at 41.
[326] Apte Direct at Exhibit AA-3, p. 11, Table 1-4; Austin Direct at 76.
[327] Austin Direct at 77.

is that reliability projects are built to enhance the normal everyday operation of the electric distribution system and ratepayers almost immediately experience the benefits of those projects.

Mr. Austin's testimony addressed Maryland's history regarding resiliency issues, including Governor Martin O'Malley's 2012 Executive Order 01.01.2012.15, which established the Grid Resiliency Task Force. The Task Force addressed the question of the "level of resiliency[328] improvement that Maryland's electricity consumers are willing to fund through rates, as this should determine the magnitude of the investments that the utilities should be allowed to make in this area."[329] Ultimately, the Task Force did not recommend specific resiliency investments. Mr. Austin noted that the PC 51 workgroup considered resiliency issues, and concluded that resilience-related metrics should be considered in the future. The workgroup noted areas of uncertainty, including insufficient data; a need to define cost/benefit analytics concerns related to paying for projects that are designed to upgrade a particular area; questions as to what the resilience metrics should be; and a need to consider how options, such as non-wires alternatives, can be used to address resiliency.[330] Mr. Austin asserted that metrics by which to determine a resiliency level and the metrics that should be used to evaluate the cost effectiveness and benefits of the alternatives are important prerequisites to establishing any resiliency investments.[331]

[328] The Task Force defined "resilience" as "the ability of the distribution system to absorb stresses without experiencing a sustained outage (i.e., over 5 minutes)." Grid Resiliency Task Force Report on *Weathering the Storm, Report of the Grid Resiliency Task Force*, September 24, 201, at 13.
[329] Austin Direct at 78, citing the Grid Resiliency Task Force Report at 13.
[330] Austin Direct at 80.
[331] *Id*. at 83.

Mr. Austin stated that certain metrics have been used by Staff to help evaluate a utility's resilience, but that they are insufficient.[332] For example, COMAR 20.50.12.06, Service Interruption Standard, focuses on the percentage of customers restored in 50 hours, and Storm Customer Average Interruption Duration Index ("SCAIDI") tracks the average customer restoration time. Mr. Austin observed that in 2021 in Case No. 9353, Staff proposed $SAIDI^{MED}$, which is the SAIDI that a system experiences during major event days. This metric represents the total time customers on average did not have service during major event days in a given year. Additionally, Mr. Austin observed that BGE proposed two metrics in this MYP, including a gray sky day metric, and protection zone customer minutes of interruption ("protection zone CMI"). The protection zone CMI metric would compare historical customer minutes of interruption with customer minutes of interruption after resiliency investments are made within a protection zone. Nevertheless, Mr. Austin asserted that "there is currently no single metric in the industry that is recognized to be the best way to gauge resiliency and I do not think that this MYP is the appropriate forum to determine what resiliency metric or metrics would balance the interests of Maryland utilities and their ratepayers."[333] Mr. Austin argued that given the magnitude of BGE's proposed $109 million resilience investment, and the absence of Commission-approved and standardized metrics to evaluate the benefit/cost and cost effectiveness of utility resilience programs, he could not support BGE's proposal.

Mr. Austin further faulted BGE for not seeking IIJA funding under the DOE GRIP for the resilience investment plan, which he argued "seems to be a perfect fit for the types

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[332] *Id*. at 83-84.
[333] *Id*. at 85.

of projects that would qualify for IIJA funding..."[334] Mr. Austin also criticized BGE's resilience investment plan because it lacked input from State and local emergency management personnel and other stakeholders, which he testified is imperative to establish electric distribution system resiliency objectives that are in sync with the entire emergency management ecosystem.[335] Finally, Mr. Austin questioned the impartiality of BGE's consultant, 1898, noting that 1898 is a subsidiary of Burns & McDonnell—an engineering, procurement and construction firm with significant interests in the planning, analysis, design and construction of electrical distribution system infrastructure.[336] Accordingly, Mr. Austin recommended that the Commission shelve BGE's resilience investment plan and establish an administrative docket to consider the implementation of resiliency standards and objectives, metrics by which to measure the effectiveness of resiliency investments, resiliency reporting requirements, and penalties for failure to meet any agreed upon resiliency standard and objective.

OPC witness Stephens likewise argued that 1898 already conducts extensive business with BGE and has a financial interest in the Commission approval of BGE's resilience investment plan.[337] Mr. Stephens also criticized 1898's model for significantly overstating the reliability improvements available from the projects. For example, he argued that 1898's resilience model undercounts the effects of past investments in distribution hardening and automation, because the model uses mostly pre-2020 data.[338] Mr. Stephens observed, however, that BGE spent about $19 million on distribution

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[334] *Id*. at 86-87.
[335] *Id*. at 81 and 86.
[336] *Id*. at 87.
[337] Alvarez-Stephens Direct at 56.
[338] *Id*. at 58.

hardening and automation after 2020, and is spending an additional $12.42 million in 2023, all of which will reduce the opportunity for additional resilience programs. He further stated that BGE's resilience model has never been validated against actual storm service interruption, which he argued is critical to the evolution and development of a model and to its predictive capabilities, and vital to instilling stakeholder confidence in its results.[339] Additionally, Mr. Stephens asserted that a majority of the circuit miles would be hardened through undergrounding, which he argued was the most costly, and cost-ineffective, approach to circuit hardening.[340] Accordingly, Mr. Stephens recommended that the Commission eliminate BGE's resilience investment plan from the Company's MYP 2.[341]

BGE witness Wright opposed the recommendations of OPC and Staff to consider the resiliency investment plan in a future proceeding and to remove the resiliency investments put forth by the Company, arguing that "now is the time to begin investing in a more resilient grid."[342] She argued that achieving Maryland's strong policy goals and preparing the grid for the impact of severe storms compel action now.[343] She also asserted that BGE's resilience investment plan "is just a first step on a longer journey," because the work proposed under the plan "is foundational to any more comprehensive electric grid distribution system resiliency and reliability program."[344]

Ms. Wright agrees with Staff that the resilience investment plan should be coordinated with FEMA and that the Maryland Department of Emergency Management

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[339] *Id*. at 62. At a minimum, Mr. Stephens argued that the model should be applied to a number of recent storms to determine how reliable the model is at predicting where grid damage and service interruptions will occur. Alvarez-Stephens Direct at 64.
[340] Alvarez-Stephens Direct at 56.
[341] *Id*. at 64.
[342] Wright Rebuttal at 4.
[343] *Id*. at 7.
[344] *Id*. at 9.

Community Lifeline Services should be prioritized.[345] Although Ms. Wright agreed with Staff that establishing appropriate resiliency metrics is important, she disagreed that establishing standardized, approved metrics is necessary before making any resiliency investments.[346] Finally, Ms. Wright testified that the concerns expressed by OPC and Staff related to 1898's financial incentive were "purely speculative and without any basis," and that the company performed an independent, objective, and professional analysis.[347] She further stated that community priorities were considered and included in BGE's resilience investment plan.

BGE witness Jason De Stigter presented rebuttal testimony addressing intervenor concerns with 1898's modeling. Mr. De Stigter stated that he is Director of 1898 and leads the Utility Investment Planning team as part of 1898's Energy and Utility Consulting Practice.[348] He disavowed any bias on the part of 1898, stating that there is no expectation or assumption that Burns & McDonnell would work on any of the identified resilience projects, and that Burns & McDonnell would follow BGE's competitive procurement process.[349] Mr. De Stigter asserted that the 107 projects identified by his firm provide benefits in excess of cost by a ratio of 4.5 times, on average.[350] He further contended that 1898's model is a credible tool that has generated reasonable results. He disputed each of the intervenors' criticisms of the model and argued that 1898's modeling did not overstate benefits, and may be producing conservative results.[351] Finally, he argued that strategic

[345] *Id*. at 14.
[346] *Id*. at 15.
[347] *Id*. at 5.
[348] De Stigter Rebuttal at 1.
[349] *Id*. at 4-5.
[350] *Id*. at 7.
[351] *Id*. at 9 and 14.

and targeted undergrounding is an effective investment solution to mitigate against major events.[352]

In his surrebuttal testimony, Staff witness Austin stated that Ms. Wright's testimony did not change his concern that there are no agreed upon resiliency standards and objectives or metrics by which to measure a utility's success in meeting those standards and objectives.[353] He stated that BGE's System Performance–Distribution category contains $415 million of largely discretionary projects and programs. Of that $415 million, Mr. Austin stated that approximately $306 million is designated for reliability projects and programs that are driven by clear regulatory standards and objectives set forth in COMAR 20.50.12.00, the compliance with which are measured by clear metrics also contained in COMAR. In contrast, the remaining $109 million proposed in the resilience investment plan do not have such standards and objectives.

Commission Decision

The Commission takes seriously its responsibilities under the Public Utilities Article to meet the renewable energy goals set by the General Assembly and to ensure the provision of reliable and adequate energy supply to Maryland ratepayers. BGE witness Wright highlighted some of the recent legislation that augments those renewable energy goals, including the 2019 Clean Energy Jobs Act (Senate Bill 516), which increased the total renewable energy requirement to 50% by the year 2030; and the CSNA of 2022 (Senate Bill 528), which set a goal of a 60% reduction in GHG emissions by 2031 and set

[352] *Id*. at 22-23.
[353] Austin Surrebuttal at 2-3.

a goal for the State to achieve net-zero statewide GHG emissions by 2045.[354] Recent legislation also requires that, in supervising and regulating public service companies, the Commission consider the preservation of environmental quality, the protection of the global climate from warming, and the achievement of the State's climate commitments for reducing statewide GHG emissions.[355]

The Commission agrees with BGE witness Wright that today's customers are more connected to technology and much more dependent on the electric grid than in years past, and that this dependency will likely increase as Maryland moves toward greater electrification of its transportation and building sectors.[356] Additionally, the risk of increased storms places greater importance on reliability and resilience measures.

Nevertheless, the Commission finds that the $109 million in expenditures envisioned by the resilience investment plan is premature at this time.[357] As Staff witness Austin discussed in his brief history of Maryland resiliency, there is a great deal of ambiguity in this subject caused by the lack of objective standards. The Grid Resiliency Task Force asked questions about the appropriate level of resiliency investments that customers would be willing to support, and that utilities should be allowed to make. However, the Task Force was not able to recommend specific resiliency investments. The PC 51 workgroup subsequently concluded that resilience-related metrics should be considered in the future, and outlined several areas of uncertainty, including insufficient

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[354] The Commission is concerned with reliability and resiliency issues. As BGE observed, the CSNA directs the Commission to begin reporting, by December 1, 2024, on distribution planning efforts that promote electric distribution system resiliency and reliability.

[355] Senate Bill 83, 2021 Md. Laws, Chs. 614, 615. *See* PUA § 2-113.

[356] *See* Wright Rebuttal at 12.

[357] Notwithstanding Mr. De Stigter's rebuttal testimony, given the magnitude of the requested investment, the Commission is also concerned about the accuracy of 1898's model, which was critiqued at length by OPC witness Stephens.

data; a need to define cost/benefit analytics concerns related to paying for projects that are designed to upgrade a particular area; questions as to what the resilience metrics should be; and a need to consider how options, such as non-wires alternatives, can be used to address resiliency.[358]

This ambiguity is emphasized by the stark contrast between the $306 million BGE proposed for reliability projects and programs, which are driven by clear regulatory standards and objectives set forth in COMAR 20.50.12.00, and the $109 million proposed in the resilience investment program, which are not. The Commission finds that it is important to have better metrics by which to determine an appropriate resiliency level, metrics to evaluate the cost effectiveness and benefits of proposed resiliency programs, and penalties for failure to meet any agreed upon resiliency standards or objectives.

The Commission also finds that this utility-specific MYP is not the best forum to fully consider resiliency metrics, including potential regulations that would measure the benefits, costs, and effectiveness of resilience programs and be applicable to all public service companies in the State. As Staff observed, any credible resiliency plan should include input from State and local emergency management personnel and other stakeholders.

Accordingly, the Commission will disallow BGE's resilience investment plan at this time and will plan to establish an administrative docket to consider the implementation of resiliency standards and objectives, metrics by which to measure the effectiveness of resiliency investments, resiliency reporting requirements, and penalties for failure to meet

[358] Austin Direct at 80.

any agreed upon resiliency standards or objectives. This disallowance is without prejudice to the refiling by BGE of similar plans, including in the Case No. 9353 reliability docket.

6. Contact Voltage Remediation Truck

BGE witness Wright testified that Commission regulations[359] require the Company to conduct contact voltage surveys within Commission-approved Contact Voltage Risk Zones ("CVRZs").[360] She stated that in order to comply with Commission regulations, BGE contracted with Osmose Utility Services ("Osmose") as having the only suitable mobile technology to effectively identify contact voltage on a large scale.[361] Ms. Wright stated that in 2016, BGE entered into an eight-year contract to utilize Osmose's technology and that the contract includes the contact voltage detection system, truck, support services, maintenance, and warranty. Nevertheless, Ms. Wright stated that the contract is due to expire in 2024 and it will be necessary to enter a new lease to continue the mandatory contact voltage survey work in accordance with the Commission's regulations. Ms. Wright stated that the only alternative to an eight-year fixed contract that is viable to BGE is a three-year service-only agreement with Osmose that is then subsequently renegotiated annually.[362] However, Ms. Wright argued that the cost of a service-only agreement over

[359] *See* COMAR 20.50.11 *et seq*., known as the Deanna Camille Green Rule. COMAR 20.50.11.01C requires that upon approval of the electric company's voltage survey plan, the electric company shall conduct an initial contact voltage survey of each CVRZ within one year of the approval and shall conduct subsequent contact voltage surveys of each CVRZ as set forth in its voltage survey plan. The Commission's regulations further provide at COMAR 20.50.11.01D that the electric company shall conduct its contact voltage surveys of: (i) All publicly accessible electric distribution plant and electric company-owned or maintained streetlights that are capable of conducting electricity; (ii) Municipal-owned or governmental-owned streetlights and traffic signals that are publicly accessible and are capable of conducting electricity (subject to the consent of the municipal government); and (iii) All objects and surfaces that are publicly accessible in public parks and playgrounds and that are capable of conducting electricity (subject to the consent of the municipal government).
[360] BGE Initial Brief at 45-46, Wright Rebuttal at 37, citing COMAR 20.50.11.
[361] Wright Rebuttal at 37.
[362] *Id*. at 39.

eight years would likely be significantly higher than the cost of an eight-year, fixed-cost term contract. Accordingly, BGE determined that now is an opportune time to enter into a capital lease regarding the technology, equipment, and truck to reduce the risk of an external party owning 100% of the assets needed to complete surveys.[363] Mr. Apte testified that the cost to BGE of the Contact Voltage Remediation ("CVR") truck and its corresponding technology is $17.5 million.[364] In a data request response to Staff, BGE stated that entering into a new contract for a newer truck with improved technology and capabilities may be more cost effective than the alternative, thereby resulting in savings.[365] However, BGE was not able to quantify the anticipated savings.

Staff witness Austin opposed BGE's proposal. He articulated several areas of deficiency in BGE's current filing, including evidence that the truck and the services Osmose provides are no longer safe and reliable; evidence that the existing technology will cease to operate or that any of the new functionalities or capabilities of the new truck are required; alternatives BGE has reviewed in order to perform contract voltage inspections beyond 2024; and evidence that the purchase of a new truck, if the Company determines that this is the best solution, will provide quantifiable savings and benefits over other alternatives.[366] Accordingly, Mr. Austin recommended that the Commission disallow this proposed $17.5 million expenditure.

OPC witness Stephens also testified against BGE's proposed expenditures related to the CVR truck.[367] He expressed concern that BGE is accounting for the contact voltage

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[363] Apte Direct at 19 and 37.
[364] *Id*. at 19.
[365] BGE Response to Staff DR 84-03(a).
[366] Austin Direct at 90.
[367] Alvarez-Stephens Direct at 90-91.

detection service provided by the third party as a capital lease and is using the structure of the third-party contract as justification. Mr. Stephens asserted that as a capital lease, the transaction increases the size of the rate base, on which customers pay BGE a return, interest expense, and taxes. Mr. Stephens argued that BGE's accounting increases costs to customers above the amount that they would otherwise pay if the service were appropriately accounted for as an O&M expense. He further contended that the transaction should be accounted for as an O&M expense rather than a purchase of a capital lease because contact voltage detection is clearly a service, not an asset.[368] He stated that the structure of the transaction exposes customers to unnecessary risk, because in the event of the third-party supplier's insolvency, the customers will be obligated to pay for contact voltage detection services from some other supplier after already paying for the $17 million initial cost in rates. Accordingly, Mr. Stephens recommended that the Commission reduce the Company's MYP by the $17.5 million capital spend proposed for contact voltage detection services in 2024, and disallow recovery of costs from customers for the net book value of the truck on the Company's books as of the start of the 2021 test year ($5.0 million).

In his rebuttal testimony, BGE witness Vahos testified that neither Staff nor OPC provided for any cost recovery for the mandatory contact voltage remediation program. He argued: "It is utterly unfair to disallow the capital lease costs while not providing any provision in rates at all for the costs of the required contact voltage."[369] BGE witness Frain argued that if the Commission elects to accept OPC's position that the contact voltage

[368] *Id*. at 90.
[369] Vahos Rebuttal at 35.

detection truck should not be treated as capital in the 2021 MYP reconciliation and be disallowed, the Commission should authorize an adjustment to the 2021 reconciliation under-recovery amount to reflect a $5 million increase to O&M expense.[370]

In his surrebuttal testimony, Mr. Austin asserted that BGE had not addressed his concerns, including quantifying any anticipated savings. Mr. Austin concluded BGE had not demonstrated that the solution the Company proposes in this MYP is the most cost-effective solution.[371]

Mr. Stephens also testified that BGE's rebuttal testimony did not change his recommendation. He asserted that BGE's negotiation of a service contract that pays a supplier $17 million up-front for several years of service, delivered by an asset with a likely value of about $100,000, and use of the contract's structure to justify capitalizing the transaction "is disingenuous in the extreme."[372] He also disagreed with Mr. Frain's alternative recommendation to reflect a $5 million increase to O&M expense, arguing that BGE's proposed recovery of the contract cost as a capital expense should be denied because the contracting structure proposed is inappropriate.[373] However, if the Commission wanted to provide some type of O&M adjustment, Mr. Stephens stated that Mr. Frain's proposed adjustment is too large as an annual adjustment and must be spread out over time, according to the table provided in Mr. Stephen's surrebuttal testimony.[374]

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[370] Frain Rebuttal at 38.
[371] Austin Surrebuttal at 14.
[372] Alvarez-Stephens Surrebuttal at 72.
[373] *Id*. at 75.
[374] *Id*.

Commission Decision

The Commission denies BGE's proposed recovery for contact voltage services as a capital expense. As OPC observes, the CVR truck is a specially equipped Ford F-150 with a fair market value of about $100,000—a tiny fraction of the $17.5 million BGE seeks to capitalize.[375] The remainder of the $17.5 million contract costs relate to operating the truck and providing contact voltage detection services. The Commission agrees with OPC witness Stephens that contact voltage detection is a service and is appropriately procured through a contract for services and accounted for as an O&M expense.[376] Moreover, the form of the transaction increases the size of the rate base, on which customers pay BGE a return, interest expense, and taxes. The structure of BGE's proposed transaction also exposes customers to unnecessary risk, because in the event of the third-party supplier's insolvency, the customers will be obligated to pay for contact voltage detection services from some other supplier after already paying for the approximately $17.5 million initial cost in rates.

Although BGE stated that entering into a capital lease for a newer truck with improved technology and capabilities may be more cost effective than alternatives, the Company was not able to quantify any anticipated savings. The Commission agrees with Staff witness Austin that BGE has not demonstrated that the solution the Company proposes in this MYP through the capital lease is the most cost-effective solution.[377]

Accordingly, the Commission accepts OPC's recommendation to remove the remaining net book value of the contract as of the last test year from the rate base and

[375] Alvarez-Stephens Direct at 88; Alvarez-Stephens Rebuttal at 61.
[376] Alvarez-Stephens Direct at 90.
[377] Austin Direct at 90; Austin Surrebuttal at 14.

reduce the 2021-2023 revenue requirements accordingly. The Commission will also disallow recovery for the $17.5 million BGE requested in its MYP application. Nevertheless, the Commission finds that BGE raises a fair point about adjusting the 2021 reconciliation under-recovery amount to reflect an increase to O&M expense. This is an important function performed by utilities to ensure safety for the public.

7. Substation Transformer Replacements (Project Number 63038) and Circuit Breaker Replacements (Project Number 67883)

BGE witness Apte testified that BGE's distribution substation transformers are aging, currently require more maintenance, and are more susceptible to failure.[378] He stated that without proactively replacing them, failures could occur and negatively impact reliability. He therefore testified in support of a proactive substation transformer replacement program, which would prioritize replacements based on age and other conditions that indicate a higher risk of failure.[379] Mr. Apte stated that the total cost of the program in this MYP period is projected to be approximately $13.1 million. He argued that benefits of the program would include reduction in system risk due to in-service failure that could also lead to extended customer outages. He also claimed that the program would reduce costs and resources associated with repair from an unpredicted failure, as well as the time and resources associated with mobile transformer deployments needed for an unpredicted failure. Mr. Apte testified that the oil circuit breaker ("OCB") program is to prevent "in-service failures through the identification and replacement of oil circuit breakers ("OCBs") that are at a higher risk of failure and will have the largest negative

[378] Apte Direct at Exhibit AA-1E, at 42.
[379] *Id*.

impact on [BGE's] other equipment and distribution system."[380] He claims there are 518 OCBs that are at least 50 years old and for which the likelihood of leaks has increased based on age, number of operations, and general wear and tear. Mr. Apte explains that similar to transformers, BGE has a prioritization process to replace the OCBs, but unlike transformers, OCBs are not designed with measures to limit impacts of oil leaks and spills.[381] BGE also included a PIM within this program, which is discussed later in this Order.

Staff witness Austin testified in support of BGE's substation transformer replacement program, finding the justifications and proposed expenditures reasonable. However, Mr. Austin asserted that BGE should reevaluate its goals of the program beyond this MYP.[382] Staff witness Austin testified in support of BGE's existing OCB program but recommended that the Commission reject the additional $4.1 million required for the accelerated OCB program, which constitutes the PIM proposal.[383]

Based on his risk-informed benefit cost analysis, OPC witness Stephens testified that the replacement of substation equipment that is old, but which has passed functional and diagnostic testing, has not been shown to deliver reliability improvements of sufficient customer value to justify the incremental costs of such replacements.[384] Specifically, Mr. Stephens calculated that the risk-informed benefits from replacing an older substation transformer with a new one amounted to only about 1/3 of the average cost to replace a transformer. Mr. Stephens argued that risk-informed benefit cost analyses are data-driven,

[380] Apte Direct at 47.
[381] *Id*. at 48.
[382] Austin Direct at 115.
[383] *Id*. at 123.
[384] Alvarez-Stephens Direct at 65.

and represent the most objective foundation for decision-making available, but that BGE did not perform such an analysis.[385] He also asserted that equipment age, by itself, "is a terrible predictor of equipment failure overall."[386] Accordingly, Mr. Stephens recommended that until BGE produces a favorable, risk-informed benefit-cost analysis, all costs associated with the Company's substation transformer replacement program and the OCB program should be disallowed and removed from the MYP.[387]

BGE witness Wright opposed OPC's recommendations regarding the substation transformer replacement program.[388] She testified that BGE has distribution substation transformers that are aging, require more maintenance, and are more susceptible to failure, with about 130 transformers that are at least 50 years old.[389] She also asserted that through a comprehensive set of factors, the program identifies transformers that are at a higher risk of failure in order to prevent in-service failures that can have negative impact on BGE's equipment and its distribution system.[390] Although the program targets transformers that are over 50 years in age, the Company uses condition assessment to prioritize the year of replacement.[391] Ms. Wright testified that BGE routinely tests transformers to determine their condition under the Company's preventative maintenance program, but that the testing cannot accurately predict the failure of a transformer which is operating satisfactorily. She stated that when a transformer fails, the substation is out of normal configuration until the transformer can be replaced, which typically takes at least six

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[385] *Id*. at 68, citing BGE Response to OPC DR 12-44(d).
[386] Alvarez-Stephens Direct at 68
[387] *Id*. at 70.
[388] Wright Rebuttal at 52.
[389] *Id*. at 52-53.
[390] *Id*. at 54.
[391] *Id*. at 53.

months. Finally, Ms. Wright disputed OPC witness Stephens' benefit cost calculations. She stated that using the risk-based cost benefit calculation proposed by Mr. Stephens, she calculated the net present value of the program to be $1.4 million, which is larger than the cost of the transformer.[392] In response to OPC's proposal to reject the OCB program, Ms. Wright claimed this would be irresponsible. Ms. Wright stated that without proactive replacement, BGE expects to see increased failures leading to outages and oil spills. Also, Ms. Wright argued that OCB's replacement parts must be custom made leading to upward pressure on costs and lead times.[393] Ms. Wright also disputed OPC witness Stephens' risk-informed cost analysis.[394] Ms. Wright's comments in response to Staff witness Austin focused on the PIM proposal.[395]

In his surrebuttal testimony, OPC witness Stephens disputed Ms. Wright's benefit cost calculations. He asserted that Ms. Wright assumed only worst-case scenarios for customer interruptions and duration and ignored average-case scenarios, thereby overstating the benefits of the program.[396]

Commission Decision

The Commission finds that the Company's program to proactively replace substation transformers and oil circuit breakers that are aging and susceptible to failure based on a multitude of testing criteria is reasonable.[397] As BGE witness Apte testified, without this proactive replacement program, failures could occur that would negatively impact reliability. Similarly, BGE witness Wright testified that when a transformer fails,

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[392] *Id*. at 54-55.
[393] *Id*. at 55.
[394] *Id*. at 56.
[395] *Id*. at 56-57.
[396] Alvarez-Stephens Surrebuttal at 55.
[397] *See* Austin Direct at 114.

the average six-month replacement time can impose additional costs and reliability issues, which can be obviated with a reasonable replacement program.[398] With regard to OPC's criticisms, BGE's program does not appear to be myopically focused on the age of the substation transformer, but rather also considers several other variables.[399] Additionally, using OPC's risk-informed benefit cost analysis, though not all of its assumptions, BGE calculated a net present value of the program that is higher than the cost of the transformer.[400]

Similar to the Commission's decision to reduce BGE's budget related to its cable replacement program, the Commission will reduce the budget for proactive transformer replacement. This is to balance the benefits of this program against costs to ratepayers. To accomplish this, the Commission will reduce the replacement and associated budgets by half in 2025 and 2026. The Commission took similar actions when it spread the costs of this program out over five years, as was done in BGE's prior MYP, Case No. 9645.[401]

The Commission will permit the budget for oil-based circuit breakers (project number 67883) without the $4.1 million budget for accelerated replacement that was envisioned by the PIM.

8. Baltimore City Conduit

BGE witness Vahos testified that since at least 1903, the Company and Baltimore City have had agreements with respect to BGE's use of the Baltimore City conduit

[398] Wright Rebuttal at 53.
[399] Ms. Wright testified that BGE used the following criteria to select the initial list (2021-2022) for replacement: Manufactured before 1960; Trending of dissolved gas analysis and other test results; Corrective maintenance work history; Condition of solid or liquid insulation; Design or parts obsolescence; Transformer Through Fault Failure Risk Internal BGE Report (mid 1980s); Weidmann Study (2006/2007); and Sirius Aging Infrastructure Initiative (2007). Wright Rebuttal at 54.
[400] Wright Rebuttal at 54-55.
[401] Order No. 89678, Case No. 9645 at 101-102.

system.[402] Mr. Vahos states that in most other jurisdictions, rate-regulated public utilities own their conduit system outright. However, Baltimore City has ownership of the entire conduit system within its jurisdictional boundaries. Accordingly, Mr. Vahos asserted that utilities in Baltimore City are required to place their facilities within the City's owned conduit system.[403] Mr. Vahos stated that BGE is required to periodically renew its agreement with Baltimore City regarding the fees BGE will need to pay for occupancy and maintenance of the conduit system, and that the City has sought to increase those fees upon each such renewal.

Mr. Vahos testified that in 2023, BGE and Baltimore City reached a new agreement regarding BGE's use of the Baltimore City conduit system.[404] Pursuant to that agreement, Mr. Vahos stated that BGE is obligated to make infrastructure investments in the conduit system. In particular, he stated that in exchange for BGE performing conduit system infrastructure investments, BGE's prior conduit fee has been reduced from previous levels.[405] Mr. Vahos further stated that although BGE will collaborate with the City on potential projects, BGE has the exclusive right to prioritize projects for the benefit of its electric customers. BGE has budgeted $10 million in 2023 and a total of approximately $110 million over the MYP period on these infrastructure investments.[406] The new contract will end on December 31, 2029.

Staff witness Dererie stated that BGE's prior agreement with Baltimore City expired at the end of June 2022, and that in the absence of an agreement on new negotiated

[402] Vahos Rebuttal at 9.
[403] *Id*. BGE is the single largest tenant of Baltimore City's conduit system and uses approximately 75 to 80 percent of the available space. Hr'g. Tr. at 606 (Singh).
[404] Vahos Direct at 52.
[405] *Id*. at 61.
[406] *Id*. at 52.

rates, BGE's most recent annual fee for maintenance and capital improvements to the conduit system would increase to $30 million.[407] She testified that under BGE's new agreement with Baltimore City, BGE is obligated to make conduit system capital improvements amounting to $120 million cumulatively over the first four years and another $92 million for the three-year extension period.[408] Compared to the MYP 1 annual spend of $26.7 million, Ms. Dererie stated that the average total Baltimore City Conduit related expenditure will increase to $42.7 million in MYP 2 under the new agreement.[409] Ms. Dererie further stated under the new agreement, Baltimore City will retain ownership and operational control of its conduit system.[410]

Ms. Dererie expressed several concerns with BGE's new agreement with Baltimore City. She observed that total Baltimore City conduit related expenditures will increase by about 50 percent under the new agreement.[411] Ms. Dererie also asserted that BGE failed to provide quantitative reliability benefits the Company and its customers will accrue from the new framework. Additionally, because BGE only occupies approximately 80% of the conduit system, Ms. Dererie expressed concern that the telecommunication and fiber companies that comprise the remaining 20% of the conduit system will realize non-ratepayer benefits that will not be directly remitted to BGE.[412] She added that BGE is not the owner of the system and has no legal or contractual authority to charge the other tenants for the improvements it makes. Finally, Ms. Dererie asserted that BGE has not yet demonstrated that this agreement is in the ratepayers' interest.

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[407] Dererie Direct at 19-20.
[408] *Id*. at 20.
[409] *Id*. at 21.
[410] *Id*. at 23.
[411] *Id*.
[412] *Id*. at 23-24.

Ms. Dererie did not recommend disallowance of associated costs at this time. Instead, she recommended that the Commission authorize Baltimore City conduit related expenditures, subject to prudence review at the reconciliation stage of this rate case.[413] Additionally, she recommended that the Commission require BGE to perform a cost benefit analysis of the new agreement that includes a demonstration of quantitative reliability and other benefits that BGE ratepayers accrued from the new framework and will continue to accrue, and quantification of all costs incurred that benefit both BGE and other non-ratepayer conduit occupiers through BGE emergency response, maintenance, and capital improvement needs.[414] She specified that BGE should allocate these costs between BGE, general conduit health and improvements and other non-ratepayer conduit occupiers, and provide a quantification of all benefits they accrue from the new agreement along with any remittances back to Baltimore City. Ms. Dererie testified that the benefit cost analysis should demonstrate that the new agreement, overall, is more cost beneficial to ratepayers compared to the previous agreement.

OPC witness Stephens criticized BGE for spending capital on an asset the Company does not own.[415] Although he acknowledged the new agreement may offer a rate reduction for customers in the short term, Mr. Stephens argued it will substantially increase customer costs in the long term. As a capital improvement, Mr. Stephens stated that customers will be required to pay back BGE—with interest, profits, and taxes on profits—over the 50-year depreciation period of the improvements.[416] Mr. Stephens also argued that capital bias

[413] *Id*. at 25.
[414] *Id*. at 25-26.
[415] Alvarez-Stephens Direct at 50.
[416] *Id*. at 51.

drove BGE's decision to enter into this new agreement, with the Company earning a return on its capital improvements under the new agreement, but not earning a return on O&M costs under the previous arrangement. Mr. Stephens expressed further concern regarding what will happen when the new contract expires. "At that point, I fear the cost of the deal to BGE customers will more than double."[417] Mr. Stephens warned that BGE does not appear to possess a contractual right to use the conduit system under the old arrangement, or any arrangement, when the current agreement expires. Additionally, Mr. Stephens asserted that investing in the conduit system is not a cost-effective way to improve reliability, because BGE's downtown Baltimore underground network is already highly reliable, with the Company unable to identify any service interruptions specifically related to the condition of the conduit.[418] Accordingly, Mr. Stephens recommended that the Commission disallow the entire $120 million in the conduit system, as it is not in the best interest of ratepayers.[419]

In his rebuttal testimony, Mr. Vahos testified that a change in Baltimore City policy regarding conduit repairs led BGE to reconsider its approach to Baltimore City and the conduit.[420] Specifically, Mr. Vahos stated that prior to 2016, the City employed a "run to failure" maintenance approach, whereby almost all conduit repairs were reactive in nature and related to collapsed or obstructed segments of conduit or manhole integrity issues. However, in 2016, Baltimore City began to proactively replace entire spans of outdated conduit and associated manholes, resulting in significantly increased user fees. However,

[417] *Id.*
[418] Alvarez-Stephens at 50, citing BGE Response to OPC DR 32-19 (a).
[419] Alvarez-Stephens at 54.
[420] Vahos Rebuttal at 10.

Mr. Vahos testified that under the new agreement, BGE receives several benefits. For example, BGE obtained the exclusive right to select and execute infrastructure investments to the conduit system that are beneficial to BGE's electric distribution system assets and those improvements can be appropriately capitalized on BGE's books.[421] Additionally, BGE received a significant reduction to the occupancy fee it pays to Baltimore City over the agreement term. BGE also obtained cost certainty at a fixed level through at least 2026 and potentially as long as 2029. Regarding Staff's recommendation for a benefit cost analysis, Mr. Vahos claimed that the evidence BGE produced in testimony, exhibits, and discovery responses capture the core benefits of the transaction, making a future cost benefit analysis unnecessary.[422] Regarding OPC's recommendation, Mr. Vahos testified that there is no merit in OPC's proposal to disallow costs that BGE is obligated to incur for the use of the conduit system that BGE's electric distribution assets occupy in Baltimore City. He stated that no party is disputing that BGE must continue to compensate Baltimore City for the use of the conduit system to operate BGE's electric distribution system; thus, the form of that compensation is not sufficient reason to eliminate cost recovery. Regarding OPC's criticism that BGE does not own the conduit system it is proposing to invest in, Mr. Vahos stated that there is a long-standing accounting standard that tenants that make improvements to an asset they are occupying can capitalize that improvement.[423]

[421] *Id*.
[422] Vahos Rebuttal at 12. In his surrebuttal testimony, Mr. Vahos' included BGE's Response to a Staff Data Request indicating that over the MYP period, customers saved almost $57 million as a result of the amended conduit agreement. Vahos Surrebuttal at Exhibit DMV-12.
[423] Vahos Rebuttal at 16. BGE witness Singh filed rebuttal testimony consistent with Mr. Vahos's arguments above. He also stated that the Baltimore City conduit system serves not just BGE's downtown Baltimore distribution network, but also non-network circuits serving 270,000 customers beyond the downtown Baltimore network.

In their respective surrebuttal testimonies, neither Staff witness Dererie nor OPC witness Stephens changed their recommendations as a result of BGE's rebuttal testimonies.[424]

Commission Decision

Consistent with Staff's recommendation, the Commission approves BGE's proposed expenditures associated with the new conduit agreement that the Company executed with Baltimore City, subject to a future prudence review at the reconciliation stage of this rate case and a benefit cost analysis.

The Commission finds that the current evidentiary record is unclear as to whether the new conduit agreement will inure to the benefit of ratepayers or impose significant future burdens. Staff and OPC raised numerous issues questioning the prudency of the decision. For example, total Baltimore City conduit related expenditures will increase by about 50 percent under the new agreement.[425] Although the new agreement may have provided a rate reduction for customers in the short term, long-term customer costs may increase as customers are required to pay back a significant debt that will be put in rate base, with interest, profits, and taxes over the 50-year depreciation period of the improvements.[426] The impact on ratepayers is made more uncertain by the relatively short term of the new conduit agreement—which expires on December 31, 2029. OPC witness Stephens warned that Baltimore City will have considerable leverage to increase its fees at that time, irrespective of BGE's significant investments in the conduit system.[427] Staff

[424] Dererie Surrebuttal at 12-13; Alvarez-Stephens Surrebuttal at 38.
[425] Dererie Direct at 23.
[426] Alvarez-Stephens Direct at 51.
[427] *Id*.

witness Dererie also raised the issue that BGE ratepayers may end up unwillingly subsidizing the 20% of non-ratepayer users of the conduit system.[428] Additionally, the benefit of BGE's right under the new agreement to prioritize projects for the benefit of its electric customers is unclear, given Mr. Stephens testimony that BGE's downtown Baltimore underground network is already highly reliable.[429]

For all of these reasons, the Commission will authorize BGE's proposed expenditures associated with the new Baltimore City Conduit agreement, but the Commission will require that BGE provide a benefit cost analysis consistent with the recommendation and the parameters provided by Staff witness Dererie.[430] Based on that analysis, BGE will be subject to a prudency review at the reconciliation stage of this MYP. BGE will have the burden of demonstrating the prudency of entering into the new agreement with Baltimore City. The Commission will also require an ongoing benefit cost analysis of the conduit agreement for ratepayers that will be presented every rate case until the costs of the contract are fully recovered, including any new contract the Company enters into with Baltimore City, benchmarked against the previous expensing contract. If it is determined this contracting decision was not cost-beneficial in conjunction with future conduit contract changes, the Commission may at that time disallow remaining unrecovered contract costs.

9. Capacity Expansion

BGE witness Apte testified that the Company's capacity expansion-distribution category includes the capital and O&M expenditures required to support electric

[428] Dererie Direct at 23-24.
[429] Alvarez-Stephens at 50, citing BGE Response to OPC DR 32-19 (a).
[430] Dererie Direct at 25-26.

distribution load growth while assuring that BGE operates a safe and reliable electric distribution system.[431] He stated that work performed in this area is driven by customer-specific requirements, aggregate customer demand, established system planning criteria and regulatory standards, and industry standards. In particular, he stated that capacity expansion distribution expenditures are driven by forecasted constraints that can be categorized by the following four primary drivers: (i) economic development and large customers;[432] (ii) decarbonization and electrification; (iii) distributed energy resource integration and interconnection;[433] and (iv) customer load growth.[434] Mr. Apte testified that typical Company expenditures include electric distribution infrastructure build outs, substation upgrades, and circuit upgrades. He stated that the overall spend in capacity expansion-distribution over the MYP 2 period will fluctuate from $76.6 million in 2024, $96.6 million in 2025, to $75.7 million in 2026.[435]

OPC witness Stephens testified that the level of capacity expansion program spending BGE has proposed within the MYP 2 period is excessive.[436] He observed that BGE's budget during the MYP 2 period will nearly double capacity expansion capital from the 2021-2022 annual average of $43.7 million. Mr. Stephens also argued that this doubling of expenditures is inconsistent with the needs of BGE's system, which are characterized

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[431] Apte Direct at 7.
[432] Mr. Apte stated that expenditures within this category are needed to construct the necessary electric distribution infrastructure to accommodate higher loads. He provided an example of the Fitzell project, which is the expansion of the Fitzell substation, to support the redevelopment of the former Sparrows Point iron and steel mill property. Apte Direct at 11.
[433] Mr. Apte stated that projects within this category relate to how BGE is adapting the way the Company plans and operates the distribution system to accommodate the installation of solar photovoltaic and energy storage systems.
[434] Apte Direct at 11.
[435] *Id*. at 14.
[436] Alvarez-Stephens Direct at 71.

by falling coincident system peak demand.[437] Although Mr. Stephens acknowledged that local pockets of growth warrant local capacity expansion projects from time to time, he contended that overall, BGE's grid does not suffer from a lack of capacity. In places where electric demand has grown, Mr. Stephens argued that BGE has proposed overspending on substation replacements, often failing to acknowledge reduced corporate office commitments and technology hub plans that have been delayed or canceled.[438] He asserted that BGE's "[c]apital bias puts continuous pressure on the capacity planning function to satisfy anticipated load growth ever-farther in advance of documented need."[439]

In response to BGE's claim that the Company must quickly prepare for EV expansion, Mr. Stephens retorted that the transition to EVs will be gradual and charging behavior will be overwhelmingly off-peak. He asserted that it will be a long time before circuit-specific load forecasts begin to reflect the impacts of EV charging. In his opinion, weaning existing buildings off the natural gas distribution network will take even longer. Accordingly, Mr. Stephens recommended that the Commission authorize BGE only its historical level of spending for capacity expansion projects in 2021 and 2022 ($43.7 million annually) during the MYP 2 period, adjusted for inflation.[440]

BGE witness Wright opposed OPC's recommendation to authorize only historical levels of spending in the Company's capacity expansion category based on actual costs in 2021 and 2022.[441] She argued that adopting this proposal would have the damaging effect of preventing the Company from building the necessary infrastructure to meet its

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[437] *Id*. at 72, citing BGE Response to OPC DR01-18(e), Attachment 3 (2021-2022); BGE Response to OPCDR12-03(b).
[438] Alvarez-Stephens Direct at 75.
[439] *Id*.
[440] *Id*. at 77.
[441] Wright Rebuttal at 43-44.

obligations to provide utility service to meet the needs of its customers and further the economic development and well-being of Baltimore and the surrounding region, while forcing BGE to decide which equipment overloads it would choose to address and which ones it would allow to occur.

Ms. Wright challenged Mr. Stephens' underlying assumptions that led to his conclusion that existing pockets of load growth could be readily accommodated with existing system capacity, including that substations with available capacity can "back-up" other substations with capacity constraints.[442] For example, she asserted that the substations would need to be geographically adjacent and there would need to be sufficient distribution ties with sufficient capacity between the substations. She also disagreed with Mr. Stephens' suggestion that several specific projects could be deferred to outside the MYP 2 period, arguing that BGE had forecasted certain substations to exceed their capacity within a relatively short timeframe.[443] For example, she stated that delay of the Claire Street substation could have "cascading impacts" on the ability of BGE to meet the forecasted load of the redevelopment at Port Covington and risk overloading equipment.[444] Ms. Wright also asserted that BGE meets frequently with developers to keep up to date with their progress and address their immediate and long-term capacity needs, so that BGE has an accurate forecast of its capacity expansion requirements.

Ms. Wright opposed what she characterized as OPC's "wait and see" approach to address overloads from area development. She argued new substation construction and substation upgrade projects take years to engineer, design, permit, and construct, and that

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[442] *Id*. at 44.
[443] *Id*. at 45-46.
[444] *Id*. at 48.

lengthening lead times for large equipment is putting further pressure on the time to execute a project in advance of reaching a capacity constraint.[445] She concluded that using OPC's reactive approach and waiting for the constraints to materialize before addressing them would result in overloaded equipment for an extended period until new infrastructure could be built.

In his surrebuttal testimony, Mr. Stephens argued that it is not necessary to eliminate 100% of overload contingency conditions, because the cost would be extreme and the expenditures would not necessarily deliver benefits in excess of those costs.[446] Mr. Stephens further asserted that a Commission decision to reduce MYP capacity expansion capital does not prohibit BGE from making the capacity expansion investments that are necessary—it only means BGE would have to wait for cost reimbursement until the next rate case or the reconciliation process.[447] Mr. Stephens also argued that BGE systematically overstates both the size and timing of projected growth in substation peak loads, which accelerates capital spending and rate increases earlier than necessary.

Commission Decision

The Commission authorizes BGE's proposed expenditures relative to its capacity expansion distribution category and declines OPC's proposed adjustment. The Commission finds that BGE has demonstrated that its proposed capital and O&M expenditures are required to support electric distribution load growth while operating a safe and reliable electric distribution system. The Company presented evidence that it needs capacity expansion to meet forecasted constraints related to economic development,

[445] *Id*. at 50-51.
[446] Alvarez-Stephens at 57.
[447] *Id*. at 58.

decarbonization and electrification, distributed energy resource integration and interconnection, and customer load growth.[448]

OPC witness Stephens argued that BGE has overstated its capacity expansion needs and recommended that the Commission reduce expenditures to BGE's historical level of spending for capacity expansion projects in 2021 and 2022. However, the Commission is concerned that such a significant curtailment of BGE's budget, when balanced against the Company's well-documented forecasts, could jeopardize the reliability of the distribution system by introducing system overloads. Additionally, the Commission finds that deferral of specific projects could have unintended consequences that could deleteriously affect reliability or economic development.[449] Moreover, as Ms. Wright averred, new substation construction and substation upgrades take years to engineer, design, permit, and construct.[450] The Commission therefore finds that it would be unreasonable to take a reactive approach to BGE's capacity expansion needs by waiting for the constraints to materialize before funding the necessary projects.

10. Fiber Optic Communications

BGE witnesses Case and Vahos testified that in September 2022, BGE submitted an application to the National Telecommunications and Information Administration ("NTIA") for an IIJA grant, which seeks to increase affordable, equitable access to high-

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[448] As with all Commission authorizations for BGE spend during the MYP 2 period, this approval is not a prudency determination. The prudency review will occur during the reconciliation process at the end of this MYP.

[449] For example, Ms. Wright testified that the Clair Street substation project involves building a new substation to replace the existing Westport 34 kV substation. However, BGE will also retire the Westport 34 kV substation and rebuild it elsewhere and utilize the space to build the expansion for the 115 kV that is required to serve the customer load that is coming online from a development. The project thereby "solves multiple problems with one solution." Hr'g. Tr. at 654-55 (Wright). As Ms. Wright testified, delaying one or more of these projects could create a cascading impact.

[450] Wright Rebuttal at 50-51.

speed internet for disadvantaged communities in central Maryland, through the Middle Mile Project, by building fiber that enables internet service providers.[451] BGE witness Vahos testified that in addition to providing connectivity for underserved communities, BGE's expansion of the fiber network would further support critical grid communications.[452] Specifically, Mr. Vahos testified that BGE's programmatic deployment of fiber will improve the reliability and resiliency of the electric grid, further enable renewables, support advanced grid applications, and facilitate clean energy technologies in support of Maryland policy goals.[453] Mr. Vahos further asserted that the project is designed to improve and expand the fiber optic network to create a robust communication backbone, which will improve reliability, resiliency, safety, and enable distributed energy resources ("DERs") and renewables.

Staff witness Dererie testified that BGE has proposed to spend approximately $112 million from 2023 through 2026 on this project, with an estimated $30 million planned for 2023.[454] Ms. Dererie stated that BGE's proposed total spend for the Middle Mile Grant Project is approximately $30.9 million, for which BGE requested approximately $15 million in funding from the NTIA, and proposed to match the funding with approximately $15 million in spending.[455] BGE intends to complete that project by 2027.[456] Ms. Dererie testified that BGE has proposed approximately $13 million to implement two grid communications and connectivity demonstration projects (Project ID 77112), whose

[451] Case Direct at 12-13; Vahos at 52. Mr. Case testified that one of the key goals of this project is to enable more affordable broadband to un-served, underserved, and economically disadvantaged communities along the project route. Case Rebuttal at 63.
[452] Vahos Direct at 19.
[453] *Id*. at Exhibit DMV-6E, p. 40; Vahos Rebuttal at 31.
[454] Dererie Direct at 29.
[455] *Id*., citing BGE Response to Staff DR 04-01.
[456] Dererie Direct at 29.

purpose is to demonstrate the viability of a fiber grid connectivity program. Ms. Dererie testified that large-scale implementation of grid fiber upgrades should only continue after demonstration of operational feasibility and viability of the pilot projects, review of expected benefits to customers, and internal management approval of the program. Ms. Dererie therefore recommended that the Commission only allow the Company to implement and recover, subject to prudency review, the $13 million of costs associated with the two demonstration projects and disallow additional expenditures.[457]

OPC witness Stephens testified against BGE's plan to expand its fiber optic communications network, arguing that available alternatives to a proprietary fiber optic network have not been adequately evaluated, making this investment proposal inappropriate.[458] Mr. Stephens agreed with BGE that utilities' need to communicate with their substations and field equipment will grow in future decades, but that need must be met at the least cost and risk for customers. Mr. Stephens asserted that fiber optic network ownership is the most capital intensive, and therefore most profitable, approach to communications network expansion that a utility can choose, but correspondingly, the most expensive to ratepayers. He stated that there are many ways a utility can communicate with its substations besides utility-owned fiber, and that many third-party data communications service suppliers are capable of meeting utility needs to communicate with their substations and other equipment.[459] Mr. Stephens argued that utilities like BGE should complete formal, independent reviews of available telecommunications network options. Because BGE has not met its burden to demonstrate that the expansion of its communications

[457] *Id*. at 30.
[458] Alvarez-Stephens Direct at 85.
[459] *Id*. at 86.

network through fiber optic ownership is the best option for customers, Mr. Stephens recommended that the Commission remove capital spending for fiber optic network expansion from the Company's MYP.[460]

In his rebuttal testimony, BGE witness Case testified that on June 16, 2023, BGE was awarded an IIJA Middle Mile Fiber grant.[461] He stated that as part of the grant requirements, BGE must spend more than $30.8 million over the next four years in order to receive the full $15 million grant that will lower the costs that customers would otherwise have borne for necessary fiber reliability and enhancement work. Addressing the concerns of Staff and OPC, Mr. Case testified that fiber is not a new technology that requires demonstration—it is instead an industry standard for communication and a best practice for utility communications, and it is used widely within the utility industry.[462] Mr. Case observed that BGE currently deploys over 900 miles of fiber to operate the grid. Mr. Case also asserted that the demonstration aspect of Project 77112 was not about the viability of fiber as a communications technology, which has been proven, but about how BGE could turn what would otherwise be just a reliability investment into an additional, beneficial opportunity for customers "by strategically planning fiber deployment in a way that could secure cost offsets such as grants and new third-party revenue streams."[463]

With regard to OPC's testimony to consider relying on third parties for communication infrastructure, Mr. Case stated that BGE does currently rely on third parties for some of its communications infrastructure. However, he noted that reliance creates risk,

[460] *Id*. at 88-89.
[461] Case Rebuttal at 2 and 61-62.
[462] *Id*. at 56-57.
[463] *Id*. at 58. Mr. Case asserted, for example, that extra capacity in the conduit could be leased to third parties that need access to additional fiber, thereby creating a potential new revenue source.

such as leaving BGE subject to third-party outages and their timeframes for issue resolution and fees.[464] He therefore opposed the recommendations of Staff and OPC to limit or eliminate the program budget. Mr. Vahos testified that at the very least, BGE needs to fund the match for the IIJA work the Company has committed to complete.[465]

In her surrebuttal testimony, Ms. Dererie maintained that the Commission should reject the proposed grid communication and connectivity project beyond what the Company proposed for its pilot.[466] Similarly, OPC witness Stephens did not change his recommendation. Despite the lure of the IIJA grant, he argued that "misspending $30 million to capture such savings does not constitute a bargain for customers."[467]

Commission Decision

The Commission will grant in part Staff's proposal by denying the fiber program budget except for the funds necessary to secure the IIJA grant. This decision results in a budget of $30.8 million.

The Commission believes that BGE's programmatic deployment of fiber may be reasonable and beneficial to Maryland's electric grid. BGE witnesses argued that the Company's expansion of its fiber network would support critical grid communications, improve the reliability and resiliency of the grid, support advanced grid applications, and facilitate clean energy technologies in support of Maryland policy goals.[468] Many distributed energy resources, including solar and battery storage, require fiber as a communication medium.[469] As Company witness Case explained during the evidentiary

[464] Case Rebuttal at 61.
[465] Vahos Rebuttal at 33.
[466] Dererie Surrebuttal at 9.
[467] Alvarez-Stephens Surrebuttal at 71.
[468] Vahos Direct at Exhibit DMV-6E at 40; Vahos Rebuttal at 31.
[469] Case Rebuttal at 58.

hearings, fiber facilitates the safe and reliable interconnection of large solar generating stations by allowing the distribution system to protect vital equipment when circuits surrounding the solar facility go down during an outage.[470] BGE's program will also provide improved connectivity to underserved communities, through the IIJA grant discussed further below.

Regarding OPC's concern that third-party data communications service suppliers or other alternatives could provide ratepayers with a more cost-effective solution, the Commission finds that BGE has adequately demonstrated in this case that there appear to be compelling reasons for BGE to develop its own fiber infrastructure. Those reasons include that BGE would be at risk of being subject to third-party outages and their timeframes for issue resolution and fees.[471]

The Commission agrees with concerns expressed by Staff and OPC about the total cost of BGE's fiber programs, and its aggregate impact on rates, when added to the many other programs proposed by BGE in this MYP. BGE has proposed to spend approximately \$112 million from 2023 through 2026 on this project, with an estimated \$30 million planned for 2023.[472] The Commission finds that the \$112 million proposed spend would impose an inordinate impact on rates.

Accepting BGE's claim that substantial funding for fiber is important for the grid of the future, but also balancing costs to ratepayers, the Commission will authorize the expenditures required of BGE to secure IIJA funding.

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[470] Hr'g. Tr. at 1102-03 (Case).
[471] Case Rebuttal at 61.
[472] Dererie Direct at 29.

BGE's application to the National Telecommunications and Information Administration ("NTIA") for an IIJA grant sought, through the Middle Mile Project, to increase affordable, equitable access to high-speed internet for disadvantaged communities in central Maryland, and BGE was awarded that grant on June 16, 2023.[473] As part of the grant requirements, BGE must spend more than $30.8 million by the end of June 2027 in order to receive the full $15 million that the NTIA authorized.[474] The Commission supports BGE's Middle Mile Project to increase affordable and equitable access to high-speed internet for disadvantaged communities, especially when coupled with the IIJA grant, which will lower the costs that customers would otherwise have borne for necessary fiber reliability and enhancement work. The Commission therefore authorizes spend on this project in the amount of $30.8 million. Additionally, the Company is directed to make a filing with the Commission within six months detailing its EM&V (evaluation, measurement, and verification) plan to study benefits as enumerated in its NTIA application and additionally the appropriateness of expanding fiber as originally envisioned in this MYP application.

11. Blue Sky Vegetation Management Pilot Program

BGE witness Singh testified that the resiliency and reliability of the electric grid is becoming increasingly important as the State moves toward widespread electrification, decarbonization of buildings, and as customer expectations continue to increase.[475] Mr. Singh asserted that at the same time as BGE is facing rising expectations and demand for the distribution of electricity, the Company's service territory is facing the threat of more

[473] Case Direct at 12 and 13; Vahos at 52; Case Rebuttal at 2 and 61-62.
[474] Vahos Rebuttal at 32.
[475] Singh Direct at 33.

severe weather. Mr. Singh testified that in 2022, BGE's service territory was impacted by more severe storms than normal, experiencing three major outage events—a frequency BGE faced only one other time (in 2003) in the Company's recent performance history.[476] Mr. Singh further testified that vegetation is the leading cause of customer outage time on the BGE system, accounting for between 31% and 50% of all customer outage minutes from 2017 to 2022.[477]

Mr. Singh testified that in response to the need for a more reliable and resilient electric distribution system, BGE proposed the Blue Sky Management Pilot Program ("Blue Sky program") He argued that the program presents an opportunity to improve reliability for customers, creates a more resilient grid that meets rising customer expectations, and advances the State's electrification goals. Mr. Singh testified that the Blue Sky program involves trimming vegetation such that there are no overhanging limbs above the power lines or in locations that potentially can impact those lines.[478] He stated that it also requires four years of clearance and the removal of trees that present an imminent danger of falling. He further provided that the program would remove overhanging limbs along the entire feeder and proactively trim and/or strategically target for removal certain tree species near BGE lines that cause most of the outages during storm events, including oaks, pines, and maples.

Mr. Singh asserted that under the Blue Sky program, BGE will select the 10 poorest performing 13.2kV circuits across its service territory, based on vegetation related outages,

[476] *Id*. at 8 and 33.
[477] *Id*. at 38; *Id*. at Table 21.
[478] Singh Direct at 33. Mr. Singh asserted that BGE's current tree trimming standards only require Blue Sky trimming between the substation and the first protective device. *See* COMAR 20.50.12.09G(2).

representing several counties and Baltimore City.[479] The 10 selected 13.2kV circuits will then be paired with 10 nearby "control" circuits that are similar in length and wooded vegetation. Mr. Singh stated that BGE will trim the 10 select circuits to the Blue Sky standard and follow up with routine cyclical trimming. He further stated that BGE will monitor the performance of these circuits starting in CY2025 and ending in CY2026. At the conclusion of the pilot program, BGE will evaluate the results and determine whether to launch the pilot as a program. Mr. Singh estimated the cost of the program will be $6 million.

If the program is approved, Mr. Singh claimed that BGE expects to reduce the number of vegetation-related outages by 25% to 50% when compared to the control circuits.[480] He testified that customers would experience multiple benefits, including more resilient circuits with fewer lengthy outages during storms, improved customer satisfaction, reduced storm costs, reduced general maintenance costs and longer asset life, reduced greenhouse gas emissions, a tree voucher program for qualifying customers, and improved safety for BGE's customers and field crews.[481] Finally, Mr. Singh testified that BGE launched a similar initiative in 2008 and 2009 with Corridor Trimming in Bowie, Maryland, and realized significant improvement of 71% to vegetation SAIFI and 64% to vegetation SAIDI.[482]

Staff witness Wilson testified that the Blue Sky program would add significant cost to BGE's vegetation management program.[483] In particular, he stated that BGE's projected

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[479] Singh Direct at 34-35.
[480] *Id*. at 35.
[481] *Id*.
[482] *Id*. at 36. *See also* Hr'g. Tr. at 597 (Singh).
[483] Wilson Direct at 14.

vegetation management budget for MYP 2 would increase by approximately $10 million from 2023 to 2024; $6 million of which would be directly attributable to this one-year pilot program.[484] Mr. Wilson testified that the approximate increased costs for Blue Sky trimming would be $73,000 per mile in addition to BGE's already budgeted routine cyclical vegetation management.[485] He asserted that this additional expense would be a substantial increase over BGE's last reported cost per mile of $13,319 in its annual report filing for CY2022. Mr. Wilson noted that BGE has not provided a benefit-cost-analysis for this program.[486]

Mr. Wilson observed that Commission regulations already provide for some Blue Sky trimming. For example, COMAR 20.50.12.09G(2) requires blue sky trimming with no overhanging limbs for voltages above 14kV and from the substation to the first protective device. Mr. Wilson asserted that utilities are free to utilize Blue Sky trimming at their discretion where this will be cost beneficial to resolve or prevent any vegetation related outage issues.[487] Given the costs of the program and the uncertainty of a positive benefit cost result, Mr. Wilson limited his support for Blue Sky trimming to corrective action only to address vegetation related interruptions beyond the substation and the first protective device when and where necessary, "as electric companies are encouraged to find ways to cost-effectively improve reliability to the electric grid."[488] However, he stated that he does

[484] Mr. Wilson asserted that the remaining $4 million is due to a combination of inflation and expected rate increases from contractors. Wilson Direct at 14.
[485] Wilson Direct at 17.
[486] Mr. Wilson noted; however, that BGE has asserted it will provide a benefit cost analysis after monitoring reliability for six months, and a final analysis by the end of the first quarter of 2025. Wilson Direct at 17.
[487] Wilson Direct at 16-17.
[488] *Id*. at 17-18.

not support approval of BGE's proposed Blue Sky program because of its high incremental costs per mile and uncertainty as to the benefit-cost.[489]

In his rebuttal testimony, Mr. Singh testified that despite the absence of a formal benefit cost analysis on the Blue Sky program, BGE can reasonably expect results that are similar to the successful program in Bowie.[490] Regarding incremental costs, Mr. Singh asserted that at the initial stage of the program, BGE will need to remove a larger volume of overhanging tree limbs and strategic trees necessary to meet the Blue Sky trimming standard, and incremental costs will be higher. However, once the initial stage is complete, he stated that future costs to maintain the Blue Sky trimming standard will be significantly lower and in line with BGE's routine tree trimming costs.[491]

Commission Decision

The Commission recognizes that Maryland utilities need to prepare for an increase in severe storms by making their distribution networks more resilient. As BGE witness Singh testified, vegetation is a leading cause of customer outage minutes on the Company's system, and targeted vegetation management is an appropriate tool that utilities may use to achieve a more resilient system. However, Staff witness Wilson provided compelling testimony regarding the high costs of the Blue Sky program. BGE's vegetation management budget for MYP 2, already $4 million higher than MYP 1 due to inflationary pressures, would be augmented by an additional $6 million.[492] The costs viewed from a per-mile basis are also quite significant. Mr. Wilson testified that the increased costs for

[489] *Id*.
[490] Singh Rebuttal at 9.
[491] *Id*. at 10.
[492] Mr. Wilson asserted that the remaining $4 million is due to a combination of inflation and expected rate increases from contractors. Wilson Direct at 14.

Blue Sky trimming would be $73,000 per mile in addition to BGE's already budgeted routine cyclical vegetation management.[493] That cost is substantially higher than BGE's last reported cost per mile of $13,319 in its annual report filing for CY2022.

Given the Blue Sky program's high incremental costs per mile and the absence of a benefit-cost analysis, the Commission adopts Staff's recommendation to disallow costs associated with this program. Nevertheless, BGE remains free to prudently utilize Blue Sky trimming where it will be cost beneficial as a corrective action to reduce tree related outages experienced by select poorest performing feeders, along with other measures to cost-effectively improve reliability to the electric grid.[494]

12. Establish and Amortize Electrification Program Regulatory Asset

BGE witness Frain provided testimony regarding Rate Base Adjustments 9 and 10, and Operating Income Adjustment 16, which reflect the establishment of a regulatory asset for the proposed Building/Non-Road Electrification Portfolio in rate base and reflect the impact of the amortization of this regulatory asset over a 12.5-year period. This issue was resolved by the Commission's August 9, 2023 Order that granted OPC's Motion to Strike, or, in the Alternative, Dismiss, the Proposed Customer Electrification Plan of BGE from its MYP 2.[495] Accordingly, Staff's adjustments are accepted on this issue.[496]

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[493] Wilson Direct at 17.

[494] As Mr. Singh and Mr. Wilson stated, the Commission's regulations already provide for Blue Sky trimming between the substation and the first protective device. *See* COMAR 20.50.12.09G(2). *See also* Singh Direct at 33; Wilson Direct at 16.

[495] *See* Order on the Office of People's Counsel Motion to Strike, Case No. 9692, *Baltimore Gas and Electric Company's Application for an Electric and Gas Multi-Year Plan*, Order No. 90755 (Aug. 9, 2023).

[496] Staff, like OPC, argued that BGE's electrification plan should be removed from the MYP. *See* Staff's June 26, 2023 Response to Motion of OPC to Strike, Maillog No. 303711, and Direct Testimony of Staff witness McAuliffe (Maillog No. 303611).

J. Gas Specific Adjustments

1. Leak Prone Pipes (LPP inclusive of STRIDE during MYP)

BGE witness White stated that BGE's Project 60677 (Operation Pipeline) program is focused on replacing cast iron and bare steel mains and services with modern materials and that BGE is seeking approval for costs associated with this program for the 2024 to 2026 MYP 2 period of $151 to $155 million per year.[497] It is this Operation Pipeline that has historically been considered Strategic Infrastructure Development and Enhancement ("STRIDE") projects. Ms. White argued that removing leak-prone pipe and repairing leaks on the system has produced material environmental benefits on the Company's distribution system, and would continue to provide additional environmental benefits over the 2024-2026 MYP 2 period.[498] In Project 58034, (Centrally Managed Gas Main Replacements), Ms. White testified that BGE proposes to replace cast iron and bare steel mains and services with modern materials.[499] Ms. White stated that BGE is currently seeking approval for costs associated with this program of $24 to $25 million per year for 2024 to 2026.

PUA § 4-210, enacted in 2013, governs the STRIDE program, which permits gas utilities, such as BGE, to recover costs for infrastructure replacement, as a safety measure, of pipes forecasted to be at risk of leakage.[500] The recovery is effectuated through a

[497] White Direct, BGE Exh. DCW-1G at 13. In greater detail, BGE provides that Project 58034 is designed to replace (or line-in-place) cast iron and other outmoded gas main assets to improve the safety and reliability of BGE's gas distribution system by eliminating infrastructure identified in BGE's Distribution Integrity Management Plan. The work supplements the Priority 1 main replacement work in Project 60666 and Project 60667 by concentrating on different cast iron assets that are generally more complex in nature and do not fit into the same workstream. White Rebuttal, Exhibit DCW-2, BGE Response to OPC DR 19.
[498] BGE Brief at 24; White Direct at 12. Ms. White testified that infrastructure replacement through STRIDE has significantly reduced natural gas leaks and resulting GHG emissions as aged, and sometimes leaky, gas assets are replaced with new non-leaking assets. Ms. White asserted that from 2017 to 2021, these replacements reduced annual GHG emissions by nearly 47,000 metric tons of CO2.
[499] White Direct, DCW-1G at 10.
[500] *See* Valcarenghi Direct at 24.

monthly surcharge on customer bills. These costs are subsequently removed from the surcharge and moved into base rates once the STRIDE investments are deemed reasonable and are closed.[501]

However, according to BGE witness White, BGE is proposing that it perform its accelerated asset replacement work within the MYP, with all cost recovery to occur through base rates set in the MYP process instead of the current combination of base rates and the STRIDE surcharge.[502]

As part of her testimony detailing the portion of the Company's proposed MYP pertaining to gas business components, Ms. White explained that BGE previously filed its accelerated gas asset replacement program under STRIDE, and BGE had previously filed a STRIDE plan and a STRIDE surcharge every five years in accordance with the STRIDE statute, but intended to not file a third STRIDE plan in 2023.[503] She testified that most of BGE's Operation Pipeline program—the primary program dedicated to replacing aging gas infrastructure and low pressure replacements—was a significant part of BGE's STRIDE program prior to this proposed MYP.[504] Ms. White indicated that BGE also has been replacing outdated and poor performing gas infrastructure through STRIDE and other programs.[505]

Ms. White testified that the change would end the STRIDE surcharge and the need to separately manage and track STRIDE-related work, but BGE's replacement plans would still remain subject to Commission oversight as part of the MYP process.[506]

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[501] *Id.*
[502] *Id.* at 5, n. 2 and16.
[503] White Direct at 5 and 16.
[504] *Id.* at 9-10.
[505] *Id.* at 10.
[506] *Id.* at 17 and 28.

This proposed change is accompanied by a change of categories in the proposed MYP—specifically, the Gas Infrastructure Modernization Program ("GIMP") category from BGE's previous MYP is not a part of the part of the proposed MYP, and the projects within that category are now placed in a new category called System Performance—Gas Distribution.[507] Ms. White stated that the capital investment for System Performance—Gas Distribution was increasing approximately \$10 million to \$15 million per year from 2024, compared to the historical spending from 2021-2023 under the GIMP category, because the Liquefaction Train Replacement and Gas Service Regulator Relocation Program projects forecasted increasing investments over the 2024-2026 period, and BGE also anticipated modest increases resulting from higher costs related to replacement of aged infrastructure.[508]

Staff witness Valcarenghi did not object to BGE's proposal, and stated that he believed that recovering STRIDE investments fully in base rates in this MYP was appropriate, not contrary to the intent of the STRIDE legislation and not subject to the legislation's monthly cap requirement as the recovery is not based on a surcharge.[509] He stated that whether BGE enacted base rate recovery or a surcharge, customers would still pay the same amount for the investments.[510]

Mr. Valcarenghi noted that BGE proposes to include STRIDE investments totaling \$151,023,844 for 2024, \$152,956,646 for 2025, and \$155,302,110 for 2026.[511] He added that BGE, in a data request response, indicated that under its proposal, it expected to

[507] *Id.*
[508] *Id.* at 25-26.
[509] Valcarenghi Direct at 26.
[510] *Id.*
[511] *Id.* at 27.

remove approximately 53 miles of mains, more than the 48 miles that BGE has historically achieved, and the Commission has allowed in previous STRIDE proceedings.[512]

Mr. Valcarenghi adjusted the level of STRIDE investments to be recovered in rates by annualizing the STRIDE funding to correlate to the Commission-authorized 48-mile removal standard, reducing BGE's estimated cost of STRIDE investments by $7.87 million in 2024, $23.69 million in 2025, and $39.75 million in 2026.[513]

Staff witness Anyinam agreed that BGE should be permitted to continue its replacement of leak prone and poor performing assets via the MYP structure, but the Commission should impose reporting requirements to, among other things, ensure the work is resulting in leak reduction.[514]

Mr. Anyinam noted that BGE typically files three STRIDE reports per year—pertaining to program and project cost variation, the STRIDE plan project list, and the proposed STRIDE project list and surcharge calculations—in addition to an annual independent auditor report.[515] He compared those requirements to BGE's two MYP-related reports filed annually, consisting of an informational report and a revised capital work plan and O&M project list.[516]

Mr. Anyinam recommended that BGE file a list of STRIDE-specific projects annually and similar in detail to those provided for the STRIDE filings, but eliminate the surcharge calculations, and include this information in the revised capital work plan and O&M project list.[517] He added that the STRIDE plan project list and the annual audit report

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[512] *Id.*
[513] *Id.* at 28.
[514] Anyinam Direct at 16.
[515] *Id.*
[516] *Id.*
[517] *Id.* at 17.

can be eliminated.[518] He elaborated that all work for the Operation Pipeline project should be subjected to the new filing requirements.[519]

Mr. Anyinam analyzed BGE's STRIDE performance compared to the Commission-approved benchmarks and found that BGE did not meet the targets, specifically, he found that: (1) BGE was approved to abandon or retire 240 miles of main in STRIDE, but Staff estimated that BGE will complete 213.86 miles; (2) BGE was approved to replace all 27,960 pre-1970 ¾-inch high pressure steel services, but will be replacing 23,782; and (3) BGE is on track to overspend its STRIDE plan approved budget by $84 million for less asset replacement than the Commission approved.[520] He noted that BGE cited supply chain issues and skilled labor shortages due to the COVID-19 pandemic, and Baltimore City work-hour restrictions as reasons for not meeting the targets, which Staff found to be legitimate.

Mr. Anyinam recommended that BGE be allowed to plan for the STRIDE main replacement in the MYP, but the Operation Pipeline project be capped at 48 miles of main replacement per year, and services replacement for Operation Pipeline be reduced to a 48 miles per year main replacement rate.[521] Mr. Anyinam recommended approval of Project 58034, (Centrally Managed Gas Main Replacements).[522]

OPC witness Hopkins testified that BGE's proposal to recover STRIDE over expenditures for the Operation Pipeline project in the MYP was "imprudently planned" because BGE's informal project selection processes indicate that the Company does not

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[518] *Id.*
[519] *Id.*
[520] *Id.* at 18-19.
[521] *Id.* at 20.
[522] *Id*. at 26 and 30.

prioritize risk reduction or cost effectiveness of various leak prone pipeline actions to reduce risk.[523] Dr. Hopkins emphasized that it was important to review BGE's leak prone pipeline investments for prudency since its last rate case.[524] However, he stated he could not recommend any specific investment line items that the Commission should disallow because BGE's planning process was not documented and did not lead to BGE taking prudent actions, and it was impossible for him to identify specific investment changes that have resulted from better planning.[525]

Instead, Dr. Hopkins recommended that for this first MYP period, the Commission disallow a portion of BGE's capital spending on mains and services – amounting to $3.38 million.[526] He argued that the Commission should send a message that if BGE's planning does not improve, the Commission could consider disallowing all investments made under the program.[527]

Dr. Hopkins expressed concerns with BGE's proposal to recover the $739,000 excess STRIDE costs related to investments in 2021 and 2022 through the MYP adjustment rider, usually reserved for reconciling spending and revenue from MYP base rates.[528]

He noted that when BGE filed its pilot MYP for 2021-2023, it was at the midpoint of its second STRIDE plan (or within STRIDE 2), necessitating the Commission's reconciliation of the existing STRIDE 2 program with the MYP, and the Commission previously decided that BGE could recover the STRIDE costs incurred during the 2021-

[523] Hopkins Direct at 5.
[524] *Id.* at 44.
[525] *Id.* at 45.
[526] *Id.*
[527] *Id.* at 46.
[528] *Id.* at 49.

2022 MYP period only via the capped STRIDE surcharge.[529] Dr. Hopkins asserted that BGE's proposal was contradictory to the Commission's previous MYP order (Order No. 89678) and the intent of the STRIDE statute, stating that the Adjustment Rider was intended to reconcile the 2022 base rate spending and revenue, and the Commission had clearly expressed a desire for BGE to keep its STRIDE spending separate from MYP base rates.[530] He recommended that the Commission not allow BGE to recover the costs through the Adjustment Rider, but add the assets that BGE installed, causing the surcharge cap overage, to the rate base starting in 2024, should the Commission determine that the investment was prudent.[531]

OPC witness Hopkins argued that BGE's proposed leak-prone pipe programs are not justified for inclusion in MYP 2 rates.[532] He argued that BGE's programs suffer from inadequate prioritization, lack of consideration for the future state and needs of the gas system (including state policies and market conditions), and no consideration of alternatives to pipeline replacement.[533] Specifically, he claimed that BGE's approach to pipe replacement, replacing assets based on general assumptions about leak potential, ignores alternative risk-mitigation measures that could provide similar safety benefits more cost effectively.[534] Dr. Hopkins argued that because most of the risk on BGE's cast iron and bare steel system is concentrated on a minority of pipelines, BGE's approach to pipeline replacement in Operation Pipeline is not cost effective. He asserted that instead of targeting the highest risk pipes, BGE's work plan is budget-driven, and based on

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[529] *Id.* at 46 and 49.
[530] *Id.* at 49.
[531] *Id.*
[532] Hopkins Direct at 50.
[533] *Id*. at 52.
[534] *Id*. at 52-53.

maintaining an average cost per mile replaced that is in line with historic averages when feasible.[535] Accordingly, Dr. Hopkins recommended that the Commission disallow Project 60677 and 58034 entirely from the MYP period of 2024 through 2026.[536]

In her rebuttal testimony, Ms. White asserted that leaks on mains and services have decreased significantly since the advent of STRIDE and BGE's work to replace leak prone pipe. She stated that BGE seeks to perform replacement work that improves the system with respect to safety and risk reduction, and tracks its work through the Company's Distribution Integrity Management Program ("DIMP") plan with mitigation activities and metrics.[537] With regard to alternatives to direct replacement, Ms. White testified that BGE does plan for cured-in-place liners for Project 58034 as an alternative for certain large diameter cast iron main replacement.[538]

On rebuttal, BGE witness Frain countered Dr. Hopkins' concerns, requesting that the Commission allow BGE to recover the STRIDE cap overages reflected in the 2021 and 2022 reconciliation amounts.[539] He explained that for the 2021 and 2022 reconciliations, STRIDE investments are reflected in the Company's plant in service, which is offset by the inclusion of STRIDE surcharge revenues.[540] He indicated that because of the offset, there would be no impact on the 2021 gas distribution revenue requirement and a minor impact of $739,000 on the 2022 gas distribution revenue requirement.[541]

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[535] *Id*. at 39.
[536] *Id*. at 7.
[537] White Rebuttal at 25.
[538] *Id*. at 63-64; White Direct at 23.
[539] Frain Rebuttal at 50.
[540] *Id.* at 36.
[541] *Id.*

Mr. Frain added that in addition to the reconciliation requests, BGE also seeks recovery of under-recoveries at the end of 2021 for Schedules EG and ISS that were capped in 2022, and under-recoveries at the end of 2022 for Schedules D, C, and IS that are capped in 2023.[542] He maintained that, despite the Commission's position on STRIDE investment recoveries in Order No. 89678, the prudency review of the reconciliation amounts for 2021 and 2022 has led the Company to request that the Commission consider inclusion in the 2022 reconciliation any revenue requirement amounts not recovered through the STRIDE surcharge, since BGE seeks to recover those amounts beginning in 2024 after the STRIDE 3 surcharge is set to $0.[543]

Mr. Frain stated that BGE is aware and the Commission recognizes the vital role of STRIDE investments in maintaining a safe and reliable gas distribution system, and he contended that the investments should be treated similarly to all other capital investments included in base rates, and BGE should be permitted to recover the full amount of the investments.[544]

Mr. Frain took issue with OPC witness Hopkins' proposal to disallow a portion of the Company's capital budget that corresponds to the capital planning function for leak-prone pipes, stating that the relevant costs Dr. Hopkins is disallowing are actually applied to two projects that are O&M in nature, Project 58449 – the Distribution Integrity Management Program ("DIMP") and Project 60069 – STRIDE.[545] Mr. Frain contended that Dr. Hopkins' proposal to adjust capital for planning dollars associated with leak-prone

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[542] *Id.*
[543] *Id.* at 36-37.
[544] *Id.* at 37.
[545] *Id.* at 41.

pipes, based on O&M activity, is inappropriate, comprises improper ratemaking, and is illogical and inconsistent. He urged the Commission to reject Dr. Hopkins' proposal.[546]

On surrebuttal, Staff witness Anyinam recommended no budget cuts for the Operation Pipeline STRIDE 2 work, as its budget was developed with the replacement rate of 48 miles per year for main lines.[547] He countered BGE witness White's objection to the continuing of STRIDE reporting requirements in the MYP, maintaining that the filings would ensure that BGE "provides upfront information that serves as a reference point regarding the scope of projects they intend to *undertake*, selection and eligibility criteria and why BGE chose certain segments for replacement and not others . . ." and other pertinent factors that would allow Staff ample opportunity to analyze the information and ensure accountability for BGE.[548]

On surrebuttal, Staff witness Valcarenghi described his concerns regarding the 48-mile installation standard set in BGE's STRIDE 2 program, noting that BGE has been unable to achieve the pipeline replacement at the established pace, per its 2022 STRIDE annual performance review, which indicates installation of 40 miles of new pipeline.[549] He added that the recent mid-year STRIDE report and testimony in this matter from BGE witness White all point to replacement thresholds below the 48 mile standard, and it should not be reflected in the development of costs that are recovered from customers in this matter.[550] He stated the 42.6 mile replacement figure provided by BGE witness White should be the baseline for the recovery of STRIDE investments for 2024-2026, and would

[546] *Id.* at 41-42.
[547] Anyinam Surrebuttal at 1.
[548] *Id*. at 11-12.
[549] Valcarenghi Surrebuttal at 8.
[550] *Id.*

result in the removal of $8.5 million in investment costs in 2024, $25.6 million in 2025 and $42.9 million in 2026.[551]

On surrebuttal, Staff witness Dr. Coates disagreed with OPC witness Hopkins' concerns—that moving STRIDE projects to the MYP would eliminate ratepayer protections and investment pace signaling in the form of the STRIDE $2 residential customer rate cap and the five-year STRIDE period—stating that protections can be met within the MYP.[552] She asserted that investment pace signals do not exist in the STRIDE program.[553] Dr. Coates echoed Staff witness Anyinam's recommendation to move the STRIDE-eligible projects into the MYP, with ratepayer protections, and agreed with his recommendation that two of the required STRIDE annual reports be incorporated into the MYP.[554]

In its brief, BGE explained its reasons for not filing a third STRIDE plan for 2023, stating that the Company has determined that maintaining two separate gas programs addressing aging, leak-prone pipes—via traditional programs incorporated into the first MYP as well as accelerated STRIDE administered programs—was burdensome, administratively inefficient and unnecessary, since the regulatory lag addressed by the STRIDE surcharge is also addressed when MYPs are used.[555]

BGE noted that the Company agrees with Staff's recommendation to file annual reports (similar to those that were previously filed through the STRIDE program for Operation Pipeline (Project 60677)) concurrently with the MYP Annual Project Lists and

[551] *Id.* at 8-9.
[552] Coates surrebuttal at 1-2.
[553] *Id*. at 3.
[554] *Id.* at 3-4.
[555] BGE Initial Brief at 24.

Informational Filings in the MYP 2 docket.[556] The Company agreed that the reports would include: "(i) annual project lists, in which BGE provides specific additional details about the individual pipeline work planned to be executed in the upcoming calendar year; and (ii) annual project completion and cost variance reports, in which BGE provides specific details about the individual pipeline work performed in the immediate prior calendar year, including any variance between estimated and actual project costs."[557]

However, BGE maintained that the Commission should dismiss Staff witness Valcarenghi's proposed downward adjustment of the revenue requirement for the pipeline work, asserting that the proposal contradicts the recommendations of the Staff's engineering expert.[558]

BGE also argued against OPC witness Hopkins' recommendations that the Commission remove the Operation Pipeline program from the MYP, require BGE to file a third STRIDE plan and surcharge, and discontinue aging gas asset replacement work until the conclusion of another STRIDE case.[559] BGE asserted that these recommendations would set bad regulatory policy and delay the filing of the third STRIDE plan until 2024 and therefore jeopardize BGE's gas system and prejudice BGE in light of its obligation under federal and State law to remove the leak-prone and aging pipelines.[560] BGE emphasized that the leak-prone pipes pose a safety risk to customers and the Company has an obligation to develop mitigating strategies for identified risks to be in compliance with PHMSA and to promote the system's safety.[561] BGE added that delays in the leak-prone

[556] *Id.* at 25.
[557] *Id.*
[558] *Id.* at 26.
[559] *Id.*
[560] *Id.*
[561] *Id.*

pipeline removal would reduce the environmental benefits of reducing GHG emissions.[562] BGE contended that incorporation of the pipeline project into the MYP would not negatively impact customers.[563]

Commission Decision

The Commission grants BGE's request to incorporate the STRIDE Operation Pipeline replacement project into the MYP, and grants Staff's request to incorporate ratepayer protections, specifically the two annual reporting requirements recommended by Staff Witness Anyinam.[564]

This approach will provide some continued oversight of the project and its progress while eliminating the surcharge and providing ample opportunity for BGE to continue the pipeline replacement work in accordance with PHMSA requirements and State law. The Commission further grants Staff's request to use the 42-mile replacement standard as the baseline in light of BGE's delay in achieving the 48-mile standard.

While the Commission, in the previous BGE MYP,[565] expressed concern that placing STRIDE projects directly into base rates could reduce transparency by requiring the Commission to approve advanced recovery of STRIDE projects with no visibility to customers, the requirement that pertinent STRIDE reporting requirements be continued should alleviate that concern.

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[562] *Id.*
[563] *Id.*
[564] The reporting requirements comprise the: (1) Annual project list, requiring BGE to provide specific details about the individual jobs to be worked through Project 60677 in the upcoming calendar year, and BGE shall file the list with the MYP Annual Project List filing; and (2) Annual project completion and cost variance filing, which shall provide specific job-level details on Project 60677 work performed in the immediate prior calendar year, including any variance between estimated and actual project costs for the year.
[565] *See* Order No. 89482.

As provided above, the Commission accepts Staff's recommendation to limit Operation Pipeline to BGE's historic achievement of 42.6 miles of main replacement per year.[566] The Commission agrees with Staff that ratepayers should not be required to pay forward rates based on an assumption that BGE can achieve a level of pipe replacement that is significantly higher than it can realistically achieve. Additionally, in order to better balance impact to ratepayers, the Commission will deny the budget for Project 58034 (Centrally Managed Gas Main Replacements) and subsume Projects 60677 and 58034 into one consolidated budget along with Proactive Service Renewals (Project 56695). BGE is permitted to spend the budget as set by Staff for project Operation Pipeline across these three projects as it sees appropriately.

Pursuant to PUA § 4-210 (g)(2)(ii), the Commission approves BGE's request to recover, through the MYP reconciliation process, the STRIDE surcharge overages from 2021 and 2022 as no projects were deemed imprudent.

2. Proactive Service Renewals (Project 56695)

BGE witness White provided testimony about Project 56695, BGE's Proactive Service Renewals project. She stated that as the STRIDE program concludes work for replacement of pre-1970s 3/4-inch high-pressure steel services in 2023, BGE anticipates additional proactive service replacement work on other poor performing service asset classes.[567] She stated that certain vintages of services have shown increased leak rates as they age, without a corresponding increase in leak rates for the associated mains. In those cases, Ms. White stated that the mains would not be part of a future replacement effort, but

[566] Staff Brief at 18.
[567] White Direct at 24.

that BGE would replace the services or components thereof to reduce the number of leaks. Ms. White asserted that targeted and proactive replacement of service assets that show enhanced risk profiles will help avoid future leaks and unplanned customer outages, thereby improving safety and reliability for customers.[568] BGE proposes to spend $4.8 million in 2024, $7.2 million in 2025, and $9.0 million in 2026 on this project.[569]

OPC witness Hopkins testified that BGE's proposal to proactively replace services through Project 56695 is excessively expensive compared with reasonable alternatives.[570] At an average capital cost of nearly $10,000 per service, and assuming typical customer usage of 500 therms per year and a utility delivery rate of 67 cents per therm, Dr. Hopkins calculated that it would take almost 30 years to pay back the cost of the service line renewal.[571] Additionally, he asserted that BGE's implicit assumption that the future demand for gas service would be similar to today was not valid. OPC generally criticized BGE's gas infrastructure investments, including Project 56695, arguing that these gas infrastructure investments are unlikely to be used over their entire lifetime and are at high risk of becoming stranded costs.[572]

Dr. Hopkins acknowledged that it would be inappropriate to leave customers without access to the services that gas provides, since they are currently being served. Nevertheless, he asserted that these customers "are being served today, and the existing asset works."[573] He argued that investing funds just to avoid a potential future leak or disruption of service is not a prudent use of resources. Accordingly, Dr. Hopkins

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568 *Id.*; BGE Exhibit DCW-1G at 9.
569 BGE Exh. DCW-1G at 9.
570 Hopkins Direct at 61.
571 *Id.*
572 OPC Initial Brief at 21.
573 Hopkins Direct at 62.

recommended that the Commission reject BGE's proposal for Project 56695 and remove the costs of this program from any future rate year.

In her rebuttal testimony, BGE witness White opposed Dr. Hopkins' recommendation, arguing that ignoring potentially leaky gas infrastructure "counters PHMSA and the entire industry's view on managing a gas system safely."[574] She argued that the purpose of the project is to address the most leak-prone and riskiest services as identified in the Company's Distribution Integrity Management Program that are not being captured through Operation Pipeline or other main replacement programs. She asserted that potential leaks on these services have a "higher probability to be hazardous, due to the proximity to the customer premises and present a risk to the customer."[575] Ms. White argued that BGE has an obligation to develop mitigating strategies for risks it identifies to be in compliance with PHMSA and to promote safety of the system, and the Company cannot simply let the system run to failure.

In his surrebuttal testimony, Dr. Hopkins clarified that he did not categorically oppose investment in leak prone pipe replacement and risk mitigation.[576] Instead, his testimony is that BGE has not demonstrated that Project 56695 (and other related programs) warrant accelerated capital recovery before the next rate case. He argued that BGE should justify any expenditures in its next rate case, or pursue accelerated recovery through the STRIDE mechanism, subject to its statutory protections, including the surcharge cap.

[574] White Rebuttal at 77.
[575] *Id*. at 78.
[576] Hopkins Surrebuttal at 33.

Commission Decision

BGE's Project 56695, Proactive Service Renewals, is designed to proactively replace certain vintages of poor performing service asset classes that have shown increased leak rates as they age, without a corresponding increase in leak rates for the associated mains. In other words, the project covers work that would not necessarily be covered by BGE's traditional STRIDE program. BGE witness White testified that the Proactive Service Renewals project will help the Company avoid future leaks and unplanned customer outages, thereby improving safety and reliability for customers.[577]

OPC witness Hopkins raised important issues related to the high cost of the project and the future of BGE's gas distribution system. For example, with an average capital cost of nearly $10,000 per service, Dr. Hopkins calculated a 30-year timeframe to recoup the cost of the service line renewal.[578] BGE responds that its Proactive Service Renewals program is appropriately targeted to address the most leak-prone services on its distribution system that are not being captured through Operation Pipeline or other main replacement programs. BGE correctly observes that it is obligated under PHMSA and Maryland regulations to operate its system safely and to develop mitigation measures to address risks. Additionally, the Commission finds that the program should enable BGE to address potential leaks on the Company's system that could present a risk to customers and prevent environmentally harmful emissions that could otherwise occur on the system.[579]

The Commission concludes; however, that BGE's proposal to spend $4.8 million in 2024, $7.2 million in 2025, and $9.0 million in 2026 on this project may impose an

[577] White Direct at 24; BGE Exhibit DCW-1G at 9.
[578] Hopkins Direct at 61.
[579] White Rebuttal at 78.

excessive burden on ratepayers. Notwithstanding that conclusion, the Commission finds OPC's recommendation to remove all of the costs of this program from any future rate year to be unreasonable. Rather than fully rejecting OPC's recommendation, the Commission will instead limit BGE's spending in accordance with Staff's recommendation in Operation Pipeline. With regard to BGE's Proactive Service Renewals project, the Commission authorizes BGE to spend dollars from Operation Pipeline on its Proactive Service Renewals project, but BGE will not be awarded additional ratepayer dollars for its Proactive Service Renewals project outside of its Operation Pipeline budget. The Commission finds that solution best balances the economic burden on ratepayers with BGE's need to maintain a safe and reliable gas distribution system.

3. BGE Transmission Investments

BGE witness White testified that the Company's capital plan for MYP 2 reflects additional work to meet PHMSA's new Final Transmission Rule ("Transmission Rule")[580] for reconfirmation of gas transmission pipeline and facility maximum allowable operating pressure ("MAOP").[581] She stated that the rule requires operators to have traceable, verifiable, and complete records to reconfirm the MAOP for all gas transmission pipelines or facilities.[582] Ms. White asserted that BGE is obligated to ensure that 50% of its transmission system meets the rule requirements by mid-2028 and 100% by mid-2035.[583] In order to meet those requirements, Ms. White claimed that BGE must invest significantly in replacement and other reconfirmation activities from 2024 through 2026.

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[580] Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments, 84 Fed. Reg. 52180 (Oct. 1, 2019) (codified at 49 C.F.R. §§ 191, 192).
[581] White Direct at 3.
[582] *Id*. at 29.
[583] *Id*. at 21.

Ms. White testified that BGE conducted an assessment and found that about 107 miles of the Company's gas transmission system and 11 gate stations did not meet the new PHMSA requirements and had record gaps, thereby requiring remediation activities.[584] Moreover, of the 107 miles of gas transmission system, approximately 70 miles were installed prior to 1970, and because of their age, are being remediated through replacement. She stated that 10 to 15 miles will be assessed for potential pressure reduction, which may require system improvements to support the reduction. She stated that the remaining mileage of transmission as well as eight gate stations will be assessed with inspection and material verifications and/or pressure testing.

OPC witness Hopkins testified that BGE did not adequately consider lower-cost alternative approaches for compliance with federal transmission pipeline safety regulations.[585] Dr. Hopkins asserted that determining the MAOP requires understanding the materials used in each segment of pipe. However, for some of its transmission pipes, Dr. Hopkins stated that BGE is unable to use its existing records to confirm the materials. Nevertheless, he argued that replacing transmission pipes is only one of the allowed options under PHMSA's Transmission Rule to determine the MAOP.[586] The other allowable methods for confirming the MAOP of a transmission pipe include (i) performing a pressure test and verifying material properties records; (ii) reducing the pressure to a level somewhat below recent operating pressure; (iii) conducting an engineering critical assessment, such

[584] *Id*. at 29.
[585] Hopkins Direct at 6.
[586] *Id*. at 66.

as in-line inspection; (iv) pipe replacement; and (v) use of alternative technology submitted to PHMSA for approval.[587]

Dr. Hopkins focused his transmission investment testimony on three projects that include Project 55633 ("Granite Pipeline – Stokes Drive to Russell Street"), Project 58079 ("Manor Loop Pipeline"), and Project 58080 ("Manor System South").[588] Dr. Hopkins stated that for each of these projects, BGE chose replacement as the preferred way to comply with the PHMSA regulation, and that the total cost over the 2024-2026 period would be $145.7 million. Dr. Hopkins claimed that BGE did not seriously consider alternative approaches for these transmission projects. Dr. Hopkins further asserted that BGE could have proposed less expensive alternatives, including performing pressure tests, conducting an engineering critical assessment, such as through in-line inspection, or reducing the pressure on the lines by a factor below the highest recorded sustained pressure. Based on PHMSA's estimations, Dr. Hopkins asserted that pressure testing costs about 10 percent as much as replacement, and engineering critical assessment costs several hundred times less than replacement [589] Dr. Hopkins argued that the high cost of replacement is not logical given the long-term future of gas, with significant decarbonization and diminution of consumption expected in future years. He contended it would be "prudent to take incremental steps that buy time before making costly and irreversible infrastructure decisions."[590]

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[587] *Id*., citing 49 C.F.R. § 192.624(c).
[588] Hopkins Direct at 66-67.
[589] *Id*. at 67.
[590] *Id*. at 68.

Accordingly, Dr. Hopkins recommended that the Commission remove expenditures on Projects 55633, 58079, and 58080 in MYP rates set for 2024-2026.[591] If BGE elects to proceed with the projects outside of the MYP, Dr. Hopkins argued the Company can propose the investments for inclusion in its next base rate case, subject to strict retrospective prudence review, which would run the risk that the costs would be disallowed in their entirety.

Sierra Club witness Walker observed that BGE operates approximately 149 miles of transmission pipe, such that the Company's plan to comply with the Transmission Rule will involve replacement of over 70% of the entire system.[592] Given that this major undertaking would cost hundreds of millions of dollars, Mr. Walker testified that it is critical that the Commission and BGE closely evaluate its necessity. Mr. Walker further asserted that much of BGE's transmission infrastructure has remaining service life and would not be replaced for years, if not for BGE's plan to reconfirm MAOP through pipe replacement.

Mr. Walker stated that PHMSA prepared an estimate of the cost to comply with the Transmission Rule, and that PHMSA concluded that only about 0.18% of the 168,000 miles of transmission pipeline in the U.S. that was installed prior to the 1970s (or 300 miles) would need to be replaced to reconfirm MAOP.[593] Mr. Walker calculated that in contrast, BGE plans to use pipeline replacement for at least 65% of its compliance efforts. Mr. Walker concluded that BGE failed to perform a comprehensive alternatives analysis

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[591] *Id*. at 69.
[592] Walker Direct at 16.
[593] *Id*. at 18-19, citing PHMSA, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," (Oct. 01, 2019) ("PHMSA Pipeline Safety Rule") at I, iii, and 52224.

to pipeline replacement and prematurely determined that certain alternatives were infeasible. He also concluded that BGE's pipe replacement strategy was inconsistent with the spirit of PHMSA's regulations, which "contemplate a low-impact minimal replacement scenario to achieve, essentially, better records, - not replaced pipes."[594] He recommended, therefore, that BGE be required to perform an alternatives analysis that does not dismiss out of hand all other alternatives for pre-1970s pipe.

In her rebuttal testimony, Ms. White argued that the intervenors' recommendations discounted robust assessments that BGE has already performed, and could result in BGE missing deadlines set forth by PHMSA in its Transmission Rule by redoing the transmission assessment or by attempting to perform alternatives that have high execution risks.[595] She additionally stated that Staff has reviewed BGE's plan and has recommended approval. In response to concerns about diminishing gas consumption and Maryland's future net zero goal, Ms. White asserted that no enacted state or federal laws currently reduce or restrict gas customers, gas appliances, gas usage, or new gas connections, but that Maryland law and PHMSA's Transmission Rule require BGE to ensure safe and reliable gas infrastructure.[596] She disagreed with Mr. Walker's citation of PHMSA's mileage estimates, and argued that the 0.18% statistic for pipe replacement was not accurate.[597] Ms. White also testified that given their age, much of BGE's transmission pipelines are not eligible for certain methods of reconfirmation, such as in-line inspection or pressure testing, or these alternatives come with considerable risk to the system or

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594 Walker Direct at 21.
595 White Rebuttal at 5 and 29-30.
596 *Id*. at i, 29-30.
597 *Id*. at 31.

customers.[598] Nevertheless, Ms. White testified that BGE is continuing to refine scope and evaluate work to meet PHMSA's Transmission Rule, and is continuing to reassess whether alternatives to replacement might be suitable for each pipeline.[599] She stated that BGE considers the original assessment performed to be "a starting point."[600]

In his surrebuttal testimony, OPC witness Hopkins asserted that Ms. White's testimony did not demonstrate that BGE sufficiently examined MAOP reconfirmation alternatives. Specifically, Dr. Hopkins argued that BGE's Gas Transmission MAOP Reconfirmation and Material Verification Plan does not document any analysis showing alternatives considered for each portion of the transmission system, or why replacement was selected.[601] Dr. Hopkins further argued that BGE could comply with PHMSA's regulations through pressure reduction, where it would reduce the pipeline's maximum pressure and flow, such as through weatherization and electrification.[602] Alternatively, he asserted that BGE could use pressure testing to set the maximum pressure. Regardless of the method chosen, Dr. Hopkins concluded that BGE should do the work it believes to be prudent and seek recovery of the resulting plant in service as part of its next rate case.

Commission Decision

The Commission finds that BGE has not demonstrated that its plan is the most cost-effective means of complying with PHMSA's Transmission Rule. OPC and Sierra Club presented convincing testimony that BGE did not adequately consider lower-cost

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[598] *Id*. at 34. For example, Ms. White testified that some of BGE's pipelines are 75 years old and have not experienced pressures as high as those used in a pressure test since they were constructed. She asserted that such a pipeline could fail or rupture during the test, resulting in costly repairs and extended, large-scale gas outages. *Id*. at 34-35.
[599] *Id*. at 33.
[600] *Id*.
[601] Hopkins Surrebuttal at 35.
[602] *Id*. at 38.

alternative approaches for compliance with federal transmission pipeline safety regulations.[603] Replacing transmission pipelines is only one of the options provided under PHMSA's Transmission Rule to reconfirm the MAOP. The allowable methods include (i) performing a pressure test and verifying material properties records; (ii) reducing the pressure to a level below recent operating pressure; (iii) conducting an engineering critical assessment, such as in-line inspection; (iv) pipe replacement; and (v) use of alternative technology submitted to PHMSA for approval.[604]

BGE witness White testified that BGE did not propose transmission pipe replacement as the only method for complying with the Transmission Rule. She stated, for example, that 10 to 15 miles of transmission pipeline will be assessed for potential pressure reduction, and that a certain amount of transmission pipeline and gate stations will be assessed with inspection and material verifications and/or pressure testing.[605] Nevertheless, the vast majority of BGE's compliance strategy involves pipe replacement, and the Company's analysis appears to heavily weigh the pipeline's age in making that determination. Sierra Club witness Walker demonstrated, for example, that BGE's PHMSA compliance plan involves the replacement of over 70% of the Company's entire transmission system.[606]

Despite party disagreement over the exact percentage, BGE's plan appears to involve significantly more pipeline replacement than PHMSA estimated would be required on average in its Transmission Rule.[607] Moreover, much of BGE's transmission

[603] Hopkins Direct at 6; Walker Direct at 20-21.
[604] 49 C.F.R. § 192.624(c).
[605] White Direct at 29.
[606] Walker Direct at 16.
[607] Mr. Walker calculated that BGE plans to use pipeline replacement for at least 65% of its compliance efforts. *Id*. at 19.

infrastructure that the Company plans to replace has remaining service life. As Mr. Walker testified: "This action is taking years to decades of remaining service life from these pipes … and discarding that pipe for early replacements in lieu of other alternatives."[608] That approach appears especially incongruous to the Commission given the uncertain long-term future of gas infrastructure in Maryland.

The record in this proceeding demonstrates that pipeline replacement—for purposes of complying with PHMSA's Transmission Rule—has the potential to be the most costly compliance method to ratepayers. BGE's plan for the 2024-2026 period would impose approximately $145.7 million on ratepayers. OPC and Sierra Club further demonstrated that less expensive alternatives, such as performing pressure tests, conducting an engineering critical assessment, or reducing the pressure on the pipelines, could substantially reduce compliance costs. Dr. Hopkins testified that pressure testing costs about 10 percent as much as pipeline replacement, and that engineering critical assessment costs several hundred times less than replacement [609] The Commission is concerned that BGE appears to have selected the most costly method of complying with the Transmission Rule, with insufficient analysis of less costly alternatives, and little to no consideration of the long-term future of gas.

Accordingly, the Commission accepts OPC's proposed adjustment that removes expenditures on Projects 55633, 58079, and 58080 in MYP rates set for 2024-2026.[610]

The Commission finds that advanced cost recovery for these projects through this MYP is not appropriate. Since the Commission is not yet convinced that BGE could only

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[608] *Id*. at 17.
[609] Hopkins Direct at 67.
[610] *Id*. at 69.

replace the impacted pipes, BGE is directed to provide a comprehensive engineering and economic analysis supporting its decision to either replace all the pipes, pursue one of the other alternatives, or a combination to comply. BGE shall consult with Staff and OPC when developing this plan. Any costs associated with these projects before the next MYP are not permitted to impact the reconciliation component of the MYP. When BGE makes its filing, the Company may provide cost recovery proposals.

4. Gas Meter Conversion Project

BGE witness Galambos addressed BGE's current Customer Operations work plan to upgrade gas meters.[611] Ms. Galambos stated that the upgrades are necessary because current advanced metering infrastructure ("AMI") communication modules contain a firmware issue that can cause the units to prematurely deplete their batteries under certain conditions.[612] As a result of the battery depletion, the communications modules prevent transmission of billable readings from the gas meters. Ms. Galambos testified that BGE intended to rectify the problem by upgrading the gas meters in two phases. First, BGE plans to upgrade approximately 45,000 of the Company's current 300G AMI communication modules[613] with new 500G communications modules.[614] Ms. Galambos asserted that the upgrade would ensure that customers can rely on the transmission of regular and consistent usage data from the gas meter to allow BGE to produce reliable and accurate bills on a

[611] Galambos Direct at 4; Galambos Rebuttal at 3.
[612] Galambos Direct, Exhibit DG-1G, at 4.
[613] Ms. Galambos testified that BGE is replacing 45,000 of the 300G modules in 2024 with more current 500G modules that do not exhibit the same battery depletion issue as the 300G modules. She further stated that BGE is replacing 200G modules which, although not suffering from the battery depletion software issue, are no longer supported by the vendor, and are nearing the end of their average useful life. Galambos Rebuttal at 4.
[614] Bunch-Shpigelman Direct at 3, citing BGE Response to Staff DR 12-05(h).

consistent basis.[615] BGE expects the first phase of the project to begin in 2023 and end in 2025, at which point the Company will begin phase two.[616]

In the second phase, BGE proposes to upgrade 100,000 gas meters to new Intelis gas meters. Ms. Galambos asserted that Intelis represents a new generation of meters that are designed with advanced safety technology, including autonomous shutoff, which allows the meter to automatically turn itself off in the event of high gas flow, regardless of system pressure; integrated thermal sensors that can detect extreme heat, thus shutting off gas flow and sending an alarm notification to BGE; theft detection; and remote disconnect capability in the event of a gas leak.[617]

Staff witnesses Bunch-Shpigelman testified that from January 2017 through January 2023, there were 127,879 instances of the 300G communications module battery depletion.[618] They further stated that during the period of 2017 through January 2023, there has been an increase in instances of reconnection failures on an annual basis. Bunch-Shpigelman stated that from 2024 through 2026, the capital cost for this project is projected to be $60,108,308, and the O&M cost for the same time period is $6,580,962, for a total cost of $66,689,270.[619]

On a percentage basis, Bunch-Shpigelman testified that the $60,108,308 capital costs are composed of $2,344,786 (4 percent) reserved for the 300G to 500G module conversions, and $57,763,523 (96 percent) reserved for the Intelis gas meter upgrades.[620]

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[615] Galambos Rebuttal at 3; Hr'g. Tr. at 482-83 (Galambos).
[616] Bunch-Shpigelman stated that BGE does not plan to begin converting gas meters to Intelis meters until 2025, because that is the year in which BGE's engineering department is expected to approve the Intelis meters for installation on the Company's system. Bunch-Shpigelman Direct at 10.
[617] Galambos Direct, Exhibit DG-1G, at 2.
[618] Bunch-Shpigelman Direct at 4, citing BGE Response to Staff DR 12-05(a).
[619] *Id*. at 6, citing BGE Response to Staff DR 81-14.
[620] *Id*.

On a unit basis, witnesses Bunch-Shpigelman calculated that the capital cost for each 300G to 500G conversion is $52.11, whereas the capital cost for each Intelis meter upgrade is $577.64—a factor of more than ten.[621] Moreover, Bunch-Shpigelman asserted that the majority of the planned Intelis gas meter upgrades would occur outside of this MYP 2 period and add additional expenses for future ratepayers. Specifically, Bunch-Shpigelman stated that BGE's full program entails upgrading approximately 574,000 gas meters with Intelis gas meters from 2025 to 2031, at a cost of approximately $277,200,000.[622] Using the estimated capital cost of $577.64 per Intelis meter upgrade, however, Bunch-Shpigelman estimated that the total capital cost to upgrade approximately 574,000 meters to Intelis gas meters could be as high as $331,565,360. Beyond cost, Bunch-Shpigelman expressed concern that under BGE's gas meter upgrade program, the Company plans to replace 428,000 gas meters prior to their 33-year average useful life. Bunch-Shpigelman also noted that BGE has identified significant unresolved risks associated with the Intelis meter upgrades.[623]

Given the significant costs, Bunch-Shpigelman recommended that BGE not be authorized to perform the Intelis meter upgrades.[624] Additionally, Bunch-Shpigelman testified that the unresolved risks and absence of a benefit cost analysis informed their recommendation. In lieu of the Intelis gas meters conversion, Bunch-Shpigelman recommended that BGE perform the 200G to 500G and 300G to 500G module conversions, the cost of which BGE estimated at approximately $55 million for capital and $2.7 million

[621] Bunch-Shpigelman Direct at 6.
[622] *Id*., citing BGE Response to Staff DR 81-04.
[623] Bunch-Shpigelman Direct at 11-12.
[624] *Id*. at 13-14.

for O&M through 2027.[625] Specifically, Bunch-Shpigelman recommended that BGE be authorized the capital cost of $2,344,786 to upgrade 45,000 200G and 300G modules to 500G in 2024, as BGE requested. For the remaining 200G and 300G modules on BGE's system, they recommended that the Company be allowed to replace half of the remaining 574,000 200G and 300G modules in CY2025, with the remaining half of the modules being replaced in CY2026. That recommendation corresponds to $14,954,524 in CY2025 and $14,954,524 in CY2026 for the capital costs of 500G module upgrades.

OPC witness Hopkins expressed concern that BGE's meter replacement project will replace approximately 428,000 meters before the end of their previously projected useful life of 33 years, with new meters that have an estimated useful life of 20 years.[626] Although BGE articulated benefits related to the Intelis gas meters, Dr. Hopkins stated that BGE has not presented any quantitative justification, through a formal benefit cost analysis, that the benefits of the program to customers merit the imposition of costs . Dr. Hopkins also argued that BGE's proposal presents a risk of additional costs to customers or stranded cost risk for BGE's investors, because meters installed under the program would all be equal to or less than 20 years old when Maryland achieves its net zero goal in 2045.[627] Dr. Hopkins asserted that there is a substantial likelihood that BGE will have fewer gas customers, and therefore need fewer meters, before the State's 2045 deadline to achieve net zero emissions.[628] He also stated that BGE has 422,000 meters installed after 2000 that have at least 10 years left on their expected useful life, and only 31,000 meters that have

[625] *Id*. at 14, citing BGE Response to Staff DR 110-03.
[626] Hopkins Direct at 70.
[627] *Id*. at 71.
[628] *Id*., citing BGE Integrated Decarbonization Strategy ("BGE Study"), Energy + Environmental Economics ("E3"), BGE Integrated Decarbonization Strategy (Oct. 2022) at 21and 27.

exceeded their 33-year expected life as of 2023, making replacement of the failing communications modules on its existing meters a much less expensive option than replacing them.

Sierra Club witness Walter testified that BGE has not demonstrated the need for the expedited gas meter conversion and replacement program.[629] He asserted that a loss of up to a week of gas meter information is not critical to the average customer; only the monthly usage is critical for the purposes of metering. He argued: "if communication is lost to a meter, as long as the month-end reading can be obtained and an accurate monthly bill issued, the issue is negligible."[630] He further contended that should a prolonged outage occur, BGE could issue an estimated bill using weather and prior use history. Additionally, he argued that even if a manual reading became necessary, the cost of doing so would be negligible compared to the meter replacement program.[631] Mr. Walter concluded that BGE does not need an accelerated meter replacement program and he therefore recommended that the Commission deny approval for recovery of funds allocated for this program.[632]

In her rebuttal testimony, BGE witness Galambos argued that the intervenor witnesses did not properly recognize the value to customers and communities of the key safety features that are only now coming on the market with the Intelis meters, including the potential to protect customers, property, and communities from the risk of serious injury due to a gas emergency event.[633] Regarding the lack of a benefit cost analysis, Ms.

[629] Walter Direct at 26-27.
[630] *Id*. at 27.
[631] *Id*.
[632] *Id*. at 28.
[633] Galambos Rebuttal at 2-3. Ms. Galambos asserted that these safety features included: remote disconnect capability; enhanced excess flow shutoff capabilities; fire danger detection; and theft detection. *Id*. at 4-5. Ms. Galambos testified, for example, that the remote disconnect capability of the Intelis gas meter would

Galambos argued that the benefits of the new safety features cannot be quantified, because they involve the value of injury prevention and saved lives.[634] Ms. Galambos stated that while BGE does not dispute that there will likely be a decline in the consumption of natural gas in Maryland in the coming, she argued that no reasonable path toward net-zero carbon emissions envisions the complete and total elimination of natural gas on the system.[635] Ms. Galambos further argued that everyone who retains natural gas service (and gas meters) deserves the highest standard of safety that is available today. Regarding the replacement of existing meters before the end of their useful lives, Ms. Galambos stated that BGE believes customers deserve the enhanced safety features of the Intelis gas meter even if their current legacy gas meter has not reached the end of its useful life.[636] Nevertheless, should the Commission not approve BGE's plan to replace all legacy gas meters beginning in 2025, Ms. Galambos asserted that the Commission should approve the installation of Intelis meters to replace legacy meters at the end of their useful lives, which she stated was authorized for Washington Gas Light Company. Finally, Ms. Galambos opposed Sierra Club's position of allowing 300G communication modules to fail and replace automatic meter reads with in-person meter readers, arguing it would require a significant increase in operational costs and entail an untenable degradation of service.[637]

allow a care center representative to respond immediately to a customer's gas odor call by shutting off the Intelis gas meter remotely and assigning a technician to perform a site visit to inspect and remediate the situation. Intelis gas meters also have integrated thermal sensors that can detect extreme heat, shut off gas flow, and send an alarm. *Id*. at 6. *See also* Hr'g. Tr. at 485-86 (Galambos).

[634] Galambos Rebuttal at 7.

[635] *Id*. at 8.

[636] *Id*. at 11.

[637] *Id*. at 12.

Commission Decision

The Commission denies BGE's proposed two-phase gas meter conversion project. Although the Intelis meter might represent state of the art technology, including autonomous shutoff features, the Commission finds that BGE has not demonstrated that the benefits of the new meter outweigh the significant economic cost that would be imposed on ratepayers. BGE has not presented any quantitative justification, through a formal benefit cost analysis, that the benefits of the program to customers merit the imposition of costs. However, witnesses for Staff, OPC, and the Sierra Club presented testimony indicating that the costs of BGE's meter replacement project exceed the expected benefits to customers, especially with respect to the installation of Intelis gas meters. As Staff noted, 96% of the capital costs of the meter conversion program relate to the Intelis meter upgrades ($57.7 million vs. the $2.3 million cost to convert 300G modules to 500G).[638] On a per-unit basis, each Intelis meter upgrade costs $577—an order of magnitude greater than the $52 cost for each 300G to 500G conversion. Additionally, full implementation of the Intelis meter upgrades would extend beyond this MYP period and impose an economic burden on ratepayers of between $277 million and $331 million.[639]

The Commission also finds concerning BGE's plan to replace approximately 428,000 meters before the end of their previously projected useful life of 33 years, with new meters that have an estimated useful life of 20 years.[640] First, technological innovation will inevitably produce new features for infrastructure that is designed to last decades. However, the Commission finds that it would not be a prudent use of ratepayer funds to

[638] Bunch-Shpigelman Direct at 6, citing BGE Response to Staff DR 81-14.
[639] *Id*., citing BGE Response to Staff DR 81-04.
[640] Hopkins Direct at 70.

scrap existing meters that have not reached the end of their useful life every time technology has produced new innovative features.[641] Second, in light of Maryland's 2045 net zero GHG-carbon emissions reduction goal, the wholesale replacement of BGE's suite of gas meters could leave customers, or shareholders, holding the proverbial bag as gas consumption is reduced.[642] As OPC witness Hopkins testified, there is a significant possibility that BGE will have fewer gas customers and therefore require fewer meters as Maryland's 2045 net zero GHG emissions reduction goal approaches.[643]

Accordingly, the Commission denies authorization for BGE to perform the Intelis meter upgrades. Instead of the Intelis gas meters conversion, BGE should perform the 200G to 500G and 300G to 500G module conversions, as recommended by Staff. Specifically, BGE is authorized capital costs of $2,344,786 to upgrade 45,000 200G and 300G modules to 500G in 2024, as BGE requested. For the remaining 200G and 300G modules on BGE's system, the Commission accepts Staff's recommendation that the Company be allowed to replace half of the remaining 574,000 200G and 300G modules in CY2025, with the remaining half of the modules to be replaced in CY2026. That recommendation corresponds to $14,954,524 in CY2025 and $14,954,524 in CY2026 for the capital costs of 500G module upgrades.

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[641] *See* Hr'g. Tr. at 72 (Hopkins), where Dr. Hopkins testified: "BGE has not justified the prudence of retiring the majority of its meters before the end of their useful life, in order to replace them with other meters that may well also be retired before the end of their useful life."

[642] Hopkins Direct at 71. BGE conceded that there will likely be a decline in the consumption of natural gas in Maryland in the coming years. Galambos Rebuttal at 8.

[643] Hopkins Direct at 72, citing BGE Integrated Decarbonization Strategy ("BGE Study"), Energy + Environmental Economics ("E3"), BGE Integrated Decarbonization Strategy (Oct. 2022) at 21 and 27.

K. Adjustments to Both Gas and Electric Revenue Requirements

1. Priority 3 Projects

In his direct testimony, BGE witness Vahos stated that the Company provided a weighing of the relative importance of work for each proposed capital project, on a scale of one to three.[644] Priority 1 represents work that the Company is required to complete: such as providing service to new customers, meeting regulations, facility relocations, preventing or restoring outages, projects that are currently under construction, and projects required to maintain COMAR compliance.[645] Priority 2 includes reliability and resiliency work needed to proactively improve system performance and prevent or minimize the potential for future customer interruptions. This category also includes Exelon utility-wide projects including IT systems and cybersecurity. Priority 3 comprises projects that support BGE's objectives to further improve its reliability performance and projects that support core business operations, which may include real estate, fleet, and other administrative/general expenses as it pertains to appropriate lifecycle replacements.[646] Mr. Vahos stated that BGE's weighing of the importance of its proposed capital projects in the MYP complied with the direction of Commission Order No. 89678. Nevertheless, Mr. Vahos asserted that all projects, regardless of the priority assigned, support system needs.[647]

Staff witness Smith testified that BGE's 2023 budgeted spend for capital projects shows a large variance vis-à-vis the budgeted spend in BGE's previous MYP.[648] He noted,

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[644] Vahos Direct at 5.
[645] *Id*. at 18-19.
[646] *Id*. at 5.
[647] *Id*. at 17-18.
[648] Smith Direct at 11-12.

for example, that BGE is forecasted to spend \$602.8 million on capital projects in 2023, \$662.2 million in 2024, \$731 million in 2025, and \$735.3 million in 2026.[649] For 2024, Mr. Smith calculated that BGE's spend is projected to increase \$59.4 million (or 9.85%) above the forecasted spend for 2023. Similarly, for 2025, BGE's spend is projected to increase by \$68.7 million (or 10.39%) above the level forecasted for 2024.[650] Mr. Smith further testified that BGE's forecasted spend of \$602.8 million in 2023 is \$157.44 million (or 35.34%) above the \$445.4 million included in BGE's work plan submitted in Case No. 9645. Mr. Smith stated that the large variance is concerning, because the Commission held in Case No. 9618 that: "A well designed MYP must ultimately balance rate stability and rising utility costs and revenues."[651] Mr. Smith asserted that BGE's proposed substantial increases in capital spending are inconsistent with the Commission's past directive regarding the need for rate stability.

Given the significant variance in proposed spending, Mr. Smith recommended reducing BGE's budgeted capital spend by removing certain Priority 3 project costs considered to be discretionary, other than the projects for which Staff Engineering witnesses either proposed adjustments or proposed support in the MYP.[652] Mr. Smith testified that the projects recommended for disallowance should not be critical to the reliability of BGE's distribution system. Mr. Smith stated that Staff has proposed similar adjustments for BGE's electric and gas systems for the MYP 2 period.[653]

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[649] *Id*. at 11.
[650] *Id*.
[651] *Id*. at 12, citing Order No. 89482 at 26.
[652] *Id*. at 13.
[653] *Id*.; Exhibit JAS-6. Staff witness Dererie also reviewed several Priority 3 projects. She asserted that affordability concerns associated with high capital and O&M plans proposed for MYP 2 informed her recommendation to disallow certain Priority 3 projects. Dererie Direct at 43.

Staff witness Anyinam provided testimony regarding Priority 3 projects related to gas. He asserted that several projects included in BGE's list of Priority 3 projects "are non-critical in nature," do not need to be performed on an expeditious basis, and if removed would not disrupt BGE's operations.[654] He further observed that BGE described much of this work as discretionary. Nevertheless, he recommended that projects that relate to higher priority work or work required for regulatory compliance be funded. Staff witness Valcarenghi presented a schedule of Priority 3 work that Staff recommended be removed from consideration in this proceeding.[655] He clarified that Staff is recommending that only a portion of the investment BGE characterized as Priority 3 work should be removed from consideration of the development of BGE's rate base in this proceeding.[656]

In his rebuttal testimony, Mr. Vahos argued that Staff misunderstood BGE's project categorization as "discretionary," arguing that the only two options in the Company's budgeting system are "mandatory" or "discretionary."[657] Mr. Vahos claimed the label "discretionary" was a misnomer, and that the project categorization labels of "mandatory" and "non-mandatory" would be more accurate. Mr. Vahos argued that the only discretion involved in non-mandatory projects is that there is "some flexibility in the timing of the work, not discretion whether the company needs to do this work or not."[658] Mr. Vahos concluded that the Priority 3 projects are important, support BGE's operational and strategic objectives and needs, and should be included in the 2024-2026 MYP revenue requirements. BGE witnesses Dickens, Galambos, Singh, White, and Wright also provide

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[654] Anyinam Direct at 24.
[655] Valcarenghi Direct at 22; Exhibit DLV-8.
[656] *Id*. at 23.
[657] Vahos Rebuttal at 30.
[658] *Id*.

examples in their respective rebuttal testimonies supporting the negative impacts of not including Priority 3 investments in the 2024-2026 MYP revenue requirements.[659]

In his surrebuttal testimony, Mr. Valcarenghi asserted that Staff did not propose a blanket disallowance of BGE's Priority 3 projects.[660] He stated that his proposed adjustments would remove $0.9 million in 2024, $2.4 million in 2025, and $4.0 million in 2026, out of total Priority 3 work requested by BGE of $36.1 million in 2024, $41.5 million in 2025, and $50.9 million in 2026. Mr. Valcarenghi further contended that BGE did not provide any evidence of potential impacts to its system or customers from accepting Staff's proposed recommendation.

Similarly, Staff witness Smith argued that Staff's total electric and gas adjustments for Priority 3 would remove $9.7 million of BGE's total Priority 3 forecasted spend of $79.3 million in 2024, $8.3 million of BGE's total Priority 3 forecasted spend of $85.5 million in 2025, and $11.1 million of BGE's total Priority 3 forecasted spend of $82.1 million in 2026.[661] Mr. Smith characterized the reductions as small relative to the total forecasted spend for the MYP period, amounting to approximately 11.8%.

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[659] Dickens Rebuttal at 19 (arguing that Priority 3 projects may be necessary to support projects in Priority groups 1, 2, or 3); Galambos Rebuttal at 16-17 (testifying that the budget for Project 56574: Customer Care Call Center Capital is needed to fund IT equipment, tools, and office construction required for the Customer Care team); Singh Rebuttal at 18-20 (contending that the budgets for several Priority 3 programs are in fact necessary, and include costs for tools used by BGE's training staff and underground crews, and to replace damaged pavement); White Rebuttal at 112 (arguing that Staff provided insufficient information as to why certain Priority 3 projects should be removed); and Wright Rebuttal at 41-42 (enumerating several programs that Ms. Wright considers important and that support the system needs, safety, and/or environmental goals of BGE.)

[660] Valcarenghi Surrebuttal at 1 and 3.

[661] Smith Surrebuttal at 8.

Commission Decision

BGE witness Vahos testified that "BGE always has more work than it can perform so that priority is often a matter of timing."[662] The Commission notes that BGE has *also* proposed more work than ratepayers should reasonably pay for, and that part of the Commission's job is to balance the needs of BGE's distribution system, including reliability, resiliency, safety, and environmental goals, with the needs of ratepayers that include affordability. In order to balance these competing interests, the Commission required in Order No. 89678 that BGE provide a weighing of its proposed capital budgets. Specifically, the Commission stated: "In future MYPs, 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."[663]

The Commission accepts Staff's proposal to disallow a portion of Priority 3 projects as reasonable. As Mr. Smith testified, BGE's proposed capital budgets demonstrate a significant increase year-to-year through 2025, and also as measured against BGE's MYP 1 budget. For example, BGE's forecasted spend on capital projects of $731 million for 2025 is 10.39% above the level forecasted for 2024.[664] Additionally, BGE's forecasted spend of $602.8 million in 2023 is $157.44 million above the $445.4 million included in BGE's work plan submitted in Case No. 9645, a 35.34% increase. The Commission stated in Order No. 89482 that "[a] well designed MYP must ultimately balance rate stability and

[662] Vahos Direct at 18.
[663] Order No. 89678 at 253.
[664] Smith Direct at 11-12.

rising utility costs and revenues."[665] The Commission agrees with Staff that BGE's capital spend as proposed does not adequately balance those factors and would impose an excessive burden on ratepayers. Staff's Priority 3 adjustments, coupled with the other adjustments enumerated in this Order, appropriately balance the needs of BGE and its ratepayers.

The Commission is not convinced by BGE's argument that Staff misunderstood the Company's labeling of certain projects as discretionary when in fact they were non-mandatory. The record demonstrates that Staff did not recommend a blanket disallowance of all BGE's Priority 3 projects. To the contrary, Staff recommended removal of only a small percentage of Priority 3 projects that it found were not critical to the reliability of BGE's distribution system, do not need to be performed on an expeditious basis, and if removed would not disrupt BGE's operations.[666] Staff left the vast majority of BGE's Priority 3 projects intact despite BGE's use of the term "discretionary." Staff's proposed reductions only removed approximately 11.8% of BGE's total forecasted spend for the MYP period. The Commission finds Staff's adjustment appropriate.

2. ADIT Corrections

OPC witness Effron proposed certain adjustments regarding ADIT, including eliminating the effect of BGE's inadvertent double counting of the amortization of the ADIT balances pertaining to the Major Outage Event Regulatory Asset.[667] Additionally, regarding the net regulatory assets for environmental costs, BGE acknowledged it inadvertently omitted from rate base the ADIT prior to adjustments and omitted the

[665] Order No. 89482 at 26.
[666] *See* Anyinam Direct at 24; Valcarenghi Direct at 23.
[667] Effron Direct at 8.

forecasted spending on environmental costs. Mr. Effron made adjustments to correct these inadvertent omissions.[668] BGE witness Frain accepted both of Mr. Effron's proposed adjustments.[669] The Commission therefore accepts OPC's adjustments.

3. Governmental, Regulatory and External Affairs

BGE included costs associated with governmental, regulatory, and external affairs ("GREA") in its MYP revenue requirements in the range of $14.3–$15.1 million for electric and $8.2–$8.5 million for gas.[670] OPC witness Effron testified that BGE's forecasted GREA expenses for the MYP period were "significantly higher" than BGE's actual 2021 and 2022 GREA expenses.[671] Mr. Effron stated that the actual electric GREA expenses were $13.1 million and $12.9 million in 2021 and 2022, respectively; and the actual gas GREA expenses were $6.4 million in both 2021 and 2022. Mr. Effron further asserted that the annualized levels of spending for the first four months of the 2023 bridge year were also well below the forecasted expenses.[672] Given the significant increase in forecasted costs for the MYP, Mr. Effron recommended adjusting BGE's GREA expenses, using the annualized level of 2023 GREA expenses as an estimate of the GREA expense for the years of the MYP.[673] However, Mr. Effron escalated those costs by 5% per year to reflect BGE's assumed 3% inflation rate plus a 2% allowance for growth.[674]

In his rebuttal testimony, BGE witness Vahos argued that OPC's high-level estimate of future costs is inappropriate given that BGE already completed a "bottoms-up

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[668] *Id*. at 9.
[669] Frain Rebuttal Testimony at 33.
[670] Vahos Direct at 45 and 59-60; Vahos Rebuttal at 25.
[671] Effron Direct at 11.
[672] *Id*. at 13.
[673] *Id*. at 13-14.
[674] Effron Surrebuttal at 8.

calculation based on the actual work needed to be done within this area."[675] Mr. Vahos also stated that BGE reexamined its presentation of information related to the expense category and reclassified seven legacy EmPOWER Maryland projects that had been inadvertently excluded from the "Other – EmPOWER MD" category in a presentation of O&M spend in Table 24 of Mr. Vahos' Direct Testimony.[676]

Mr. Vahos further asserted that OPC ignored several critical new GREA functions during the 2024-2026 MYP period.[677] For example, Mr. Vahos testified that BGE's Infrastructure Academy project is an initiative where BGE, contractors, and non-profit partners collaborate to train "work ready" adults and connect them to construction careers.[678] He testified regarding three additional GREA programs: (i) Community Engagement, which provides funding for additional staffing within GREA to assist BGE with the permitting process to help ensure work is able to begin as scheduled; (ii) Grid Communications and Connectivity OM, which supports the Company's corresponding capital Project 77112, which in turn encompasses programmatic deployment of fiber to improve the reliability and resiliency of the electric grid, enable renewables, support advanced grid applications, and enable clean energy technologies; and (iii) Project Zero – OM, which supports BGE's Path to Clean initiative, focused on reducing BGE operations-driven GHG emissions 50% by 2030 and achieve net-zero emissions from operations by

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[675] Vahos Rebuttal at 23.
[676] *Id*. at 23-24. *See also* Hr'g. Tr. at 906 (Vahos). The Commission notes that some of the confusion on the GREA issue could have been avoided if BGE had provided this information in its initial Application and direct testimony, instead of its rebuttal testimony. As the Commission stated regarding Supplier Consolidated Billing, above, the utility should provide all pertinent information upfront, in direct testimony. Parties should not have to wait for rebuttal or live rejoinder testimony to obtain information necessary to formulate their litigation position.
[677] Vahos Rebuttal at 23-24.
[678] *Id*. at 25-26.

2050.[679] Mr. Vahos concluded that after taking into consideration these new BGE projects, the remaining proposed 2024–2026 GREA O&M expense is in line with 2022 actual O&M and the 2023 forecasted O&M. Accordingly, Mr. Vahos recommended that OPC's proposed reduction of GREA O&M be rejected.[680]

In his surrebuttal testimony, Mr. Effron updated his proposed adjustment using actual costs for the first six months of 2023.[681] During his live rejoinder testimony at the hearing, Mr. Vahos disputed Mr. Effron's annualization of costs for 2023 and provided an alternative annualization of $12.1 million for electric and $7.5 million for gas.[682] Mr. Vahos also applied Mr. Effron's escalation method to revise his adjustments to BGE's proposed GREA expenses, which Mr. Effron accepted at the evidentiary hearing.[683] BGE also identified certain lobbying expenses that should have been removed from the MYP revenue requirement, and that were subsequently included in Mr. Effron's testimony.[684]

Commission Decision

The Commission approves OPC witness Effron's proposed adjustment, subject to the additional modifications described below. The Commission agrees with OPC that the forecasted costs included in BGE's GREA MYP have grown significantly vis-à-vis the 2021-2022 period. Additionally, irrespective of the value of new programs discussed by BGE witness Vahos, the total proposed budget for BGE's GREA has grown such that the Commission is concerned about ratepayer impact. Accordingly, the Commission finds

[679] *Id*. at 27.
[680] *Id*. at 28-29.
[681] Effron Surrebuttal at 7-8.
[682] BGE Exhibit 44 (Corrected Effron GREA Adjustment).
[683] Hr'g. Tr. at 1632 (Sammartino).
[684] Effron Surrebuttal at 8-9. Mr. Effron testified that in response to OPC data request 51-05, BGE identified lobbying expenses that should have been removed from the MYP, which Mr. Effron eliminated on Exhibit DJE-6, Schedule C-1.

reasonable Mr. Effron's proposal to use the annualized level of 2023 GREA expenses, adjusted by an escalation factor of 5% per year to reflect a 3% inflation rate plus a 2% allowance for growth.

During the evidentiary hearing, BGE witness Vahos provided a comparison table (BGE Exhibit 44) proposing certain changes to Mr. Effron's calculations based on Mr. Vahos' rejoinder testimony.[685] OPC agreed to the modifications proposed by Mr. Vahos.[686] Accordingly, the Commission accepts Mr. Effron's proposed adjustment to BGE's GREA MYP, as modified by BGE Exhibit 44.

On brief, the Sierra Club argued that the Commission "should direct that all trade association dues be treated as below the line expenses so that ratepayers are not forced to financially support advocacy they may disagree with."[687] While no party offered an explicit adjustment nor was this issue raised through testimony, the Commission believes Sierra Club raises important questions about the appropriateness of funding trade association dues when those trade associations' advocacy may not align with State policy. The Commission encourages parties to scrutinize these trade association dues and it will consider the appropriateness of continuing to allow them in future rate cases. The Commission also encourages parties to scrutinize expenses associated with advancing company business interests (e.g. at PJM) to ensure alignment with State policies and the public interest, and to propose adjustments if expenses are found to be misaligned.

685 BGE disputes Mr. Effron's use of annualized 2023 expenses. Vahos Rebuttal at 23. However, BGE argues that if any adjustment is approved by the Commission, it should align with BGE Exhibit 44. BGE Initial Brief at 53.

686 Hr'g. Tr. at 1632 (Sammartino); Hr'g. Tr. at 1228 (Effron); OPC Reply Brief at 59.

687 Sierra Club Br. at 43.

L. Proposals for Additional Information

1. Enterprise Asset Management – EAM 2.0 Asset Suite 8 Replacement Project

BGE witness Vahos testified that BGE's current asset management software platform, Asset Suite 8, has reached the end of its useful life and needs to be upgraded and/or replaced.[688] He asserted that BGE's Enterprise Asset Management ("EAM") Asset Suite 8 Replacement project ("EAM 2.0 Project") is a key capital IT project in the 2024-2026 MYP plan.[689] He stated that the EAM 2.0 Project is focused on designing and implementing a new work and assets management platform. He stated that this platform will improve user experiences and asset management through end-to-end process designs with user insights into work status, updated data models, new asset types, and improved technical integration and performance. In response to Staff data requests, BGE stated that this project is still in the assessment phase and that the Company is evaluating alternatives.[690]

Staff witness Dererie articulated concerns with BGE's EAM 2.0 Project, noting that BGE has not provided cost benchmarks to help demonstrate that the project is a prudent investment.[691] Ms. Dererie also asserted that BGE may be upgrading its existing system without a thorough vetting of alternatives, noting that the Company has not provided a review of alternatives evaluated and expected benefits to the Company and its customers.[692] Accordingly, Ms. Dererie recommended that the Commission approve the EAM 2.0 Project subject to a later prudency review. She further recommended that the

[688] Vahos Direct, Exhibit DMV-6E, at 14.
[689] *Id*. at 47.
[690] Dererie Direct at 12, citing BGE response to Staff DR No. 103-08.
[691] *Id*. at 13.
[692] *Id*.

Commission require BGE to provide, before January 1, 2024, a document that is used for internal management approval that shows alternatives reviewed, cost and benefit of each alternative, timeline of implementation, and any other information (including benchmarking information, if available) to demonstrate that the EAM 2.0 Project is a prudent investment.[693]

In his rebuttal testimony, Mr. Vahos argued that the January 1, 2024 deadline was arbitrary and would be difficult to meet.[694] He argued that there is no need to circumvent the project's internal timelines in order to review materials by January 1, 2024, because projects should be allowed adequate time to prepare and proceed through the management approval process. He further stated that management materials may not be available by January 1, 2024. Finally, he stated that BGE has already provided internal management materials for Phase 1 of the EAM 2.0 project.

In her surrebuttal testimony, Ms. Dererie maintained her request for the information, but revised her recommendation to require BGE to provide the requested information prior to the Company's implementation of the selected solution.[695]

Commission Decision

BGE presented evidence that its existing asset management software platform, Asset Suite 8, should be upgraded or replaced. BGE has also presented testimony that its EAM 2.0 Project will provide important benefits, including improved user experience, a wider array of technical features, and advanced performance capabilities.[696] Staff witness

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[693] *Id*.
[694] Vahos Rebuttal at 55.
[695] Dererie Surrebuttal at 18.
[696] Vahos Direct at 47.

Dererie reviewed the Company's supporting testimony and documentation and recommended that the Commission approve funding for the EAM 2.0 Project through the MYP 2 period. However, Ms. Dererie also raised concerns about the project. Namely, she testified that BGE has not provided cost benchmarks to demonstrate that the project is a prudent investment, or evidence that the Company has thoroughly vetted alternatives.[697]

The Commission agrees with Ms. Dererie that the EAM 2.0 Project should be funded for the MYP 2 period, and that it should be subjected to a full prudency review thereafter. In order to facilitate that review, the Commission directs BGE to provide documentation that is used for internal management approval that shows total project costs, alternatives reviewed, costs and benefits of each alternative (including quantitative and qualitative), timeline of implementation, and any other information (including benchmarking information, if available) to demonstrate that the EAM 2.0 Project is a prudent investment. Given that BGE has stated that this project is still in the assessment phase and that the Company is evaluating alternatives, BGE is directed to provide the information requested by Staff prior to BGE's implementation of the selected solution.

2. ADMS Related Expenditures

BGE witness Vahos testified that the Company's Advanced Distribution Management System ("ADMS") is an IT project focused on enabling BGE's distribution system to adapt and transform in support of changing customer needs and market shifts anticipated by grid modernization.[698] Mr. Vahos stated that the ADMS program will replace BGE's existing Outage Management Systems ("OMS") across Exelon Utilities.[699]

[697] Dererie Direct at 13.
[698] Vahos Direct at 47.
[699] Vahos Direct, Exhibit DMV-6E at 13.

He stated that ADMS will feed into the Outage Reporting & Analytics platform, and will limit the number of systems that can connect directly to its database.

Staff witness Dererie testified that the Commission already approved four projects related to ADMS in MYP 1, subject to prudence review, and that these projects are continuing through the MYP 2 period.[700] Ms. Dererie stated that BGE is now proposing four new projects for MYP 2: (i) Project 78280 – Exelon Utilities Reporting & Analytics ADMS Integration; (ii) Project 78282 – Exelon Utilities Outage Reporting and Analytics Implementation; (iii) Project 85295 – Exelon Utilities Network Refresh; and (iv) Project 84816 – Exelon Utilities ADMS Convergence Stage 2 projects.

Regarding Project 84816, Ms. Dererie asserted that BGE has not provided evidence of alternatives considered. In responses to Staff data requests, BGE stated that the project is still in the planning phase and is expected to be completed by 2029, and that the management approval documentation will not be available until the planning phase is complete.[701] Ms. Dererie did not raise concerns with BGE's other three projects under ADMS. Accordingly, Ms. Dererie recommended that the Commission approve Project 78280, Project 78282, Project 85295, and Project 84816, subject to prudence review at reconciliation.[702] However, regarding Project 84816, Ms. Dererie recommended that BGE provide the documentation used for management approval in the 2026 project list filing or for any year the Company plans to start implementation of Project 84816. Specifically, she requested BGE provide the alternatives reviewed, any risks associated with starting Stage 2 while also implementing Stage 1 ADMS solutions, total project cost, timeline of when

[700] Dererie Direct at 14.
[701] *Id*. at 16.
[702] *Id*. at 17.

the project will be complete and a discussion of quantitative and qualitative benefits to the Company and its customers.

In his rebuttal testimony, Mr. Vahos asserted that BGE has provided available project presentations as part of the MYP proceeding.[703] He added that BGE will share with Staff internal management approval presentations for the four ADMS projects, once those become available.

Commission Decision

The Commission accepts Staff's recommendation to approve funding during the MYP 2 period of the four new ADMS related projects: Project 78280, Project 78282, Project 85295, and Project 84816, subject to prudence review at reconciliation. Regarding Project 84816, the Commission requires that BGE provide the information requested by Staff. In particular, BGE is directed to provide the internal management approval documentation that includes a review of alternatives, any risks associated with starting Stage 2 while also implementing Stage 1 of the ADMS program, total project cost, project timeline, and discussion of quantitative and qualitative benefits of the project to the Company and ratepayers. BGE should provide this information when it becomes available.

M. Reconciliation from Case No. 9645 (2021 and 2022)

BGE has requested rate recovery of reconciliation amounts from the 2021 and 2022 rate years. The total amount of reconciliation funding requested is $52.2 million for electric and $21.8 million for gas. Stakeholders have challenged components of that total. The following table outlines the Commission's permitted recovery of costs by category; the

[703] Vahos Rebuttal at 55.

costs for SCB, Common Trench, and Contact Voltage Truck were discussed in prior sections.

Table 4

	Electric	
	2021	2022
Unadjusted Results	$ 18,190	$ 49,935
Adjustments		
Uncontested Adjustments	$ (7,478)	$ (5,989)
Disallowance Common Trench	$ (188)	$ (405)
Split cost 50/50 Common Trench Gas & Electric	$ (314)	$ (628)
Plant Disallowances	$ -	$ -
Supplier Consolidated Billing	$ -	$ -
Contact Voltage Service*	$ (2,700)	$ (2,600)
Remove External Affairs Costs	$ -	$ (660)
Expense Contact Voltage Truck	$ 5,132	$ -
Property Taxes	$ (62)	$ (128)
Interest Synchronization	$ 27	$ 56
Reconciliation Amount	$ 12,607	$ 39,582

Table 5

	Gas	
	2021	2022
Unadjusted Results	$ 9,507	$ 17,580
Adjustments		
Uncontested Adjustments	$ (2,390)	$ (2,794)
Remove SCB O&M	$ -	$ -
Remove Excess Locating Costs	$ -	$ (552)
Remove Gas Plant- Net	$ -	$ -
Adjust STRIDE Recovery	$ -	$ -
Disallowance Common Trench	$ (233)	$ (503)
Split cost 50/50 Common Trench Gas & Electric	$ 391	$ 780
Reconciliation Amount	$ 7,275	$ 14,511

1. Locating Electric and Gas

Staff

Initially, Staff witness Clementson recommended that the Commission disallow the full amount of overspend on Projects 61220 and 61222, Gas and Electric O&M Expenses for CY2021 and CY2022 subject to BGE's response to certain data requests.[704] In his direct testimony, witness Clementson details the budgeted versus the actual expenses associated with the Company's Utility Locating activities for gas and electric in CY2021 and CY2022.[705] The table shows the combined overspend for Projects 61220 and 61222 for CY2021 and CY2022 associated with utility locating.

Table No. 6
Actual Total Overspend for Electric and Gas for CY2021 and CY2022[706]

Calendar Year	Actual Total Overspend	Percentage of Total Overspend
CY 2021		
Electric	$121,529	3.7%
Gas	$242,999	7.3%
CY 2022		
Electric	$981,878	29.7%
Gas	$1,963,755	59.3%
Total	$3,310,161	

[704] Clementson Direct at 2.
[705] *Id*. at 9-13.
[706] Table 6 adapted from Table 6 in Clementson Direct at 12.

In his surrebuttal testimony, witness Clementson changed his recommendations based on the Company's clarifications and responses to data requests. Mr. Clementson stated that Company witness White clarified that the purpose of Projects 61220 and 61222 was to support gas and electric damage prevention including projects such as "quality audits of utility locating work, outreach to and education of the excavator community, and participation in Maryland's One Call Center service to facilitate the utility locating process."[707] He noted Company witness White pointed out that his direct testimony contained a few mistakes in how the budget and actual expenses for Project 61220 and 61222 were displayed.[708] Ms. White also explained that the values displayed in Table 6 in Mr. Clementson's direct testimony and adapted above as Table 6, inadvertently show a higher level of overspend.[709] In response to Staff DR No. 151-02, the Company indicated that it did not begin allocating costs between gas and electric lines of business until 2023. Therefore, in 2021 and 2022, all actual and budget expenditures under Project 61220 Damage Prevention were reported under the gas line of business.[710]

On surrebuttal, Mr. Clementson also noted that the Company provided explanation for incremental damage prevention costs attributed to increased contractor costs associated with Project 61220 in 2021 and 2022. The Company explained that it had a shorter than optimal transition period between vendors and that "the locating vendor in 2021 and 2022 experienced staffing challenges as a result of the pandemic and tight labor market which impacted the timeliness of marking."[711] BGE indicated that as a result it incurred additional

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[707] Clementson Surrebuttal at 4.
[708] *Id*.
[709] *Id*.
[710] *Id*. at 5.
[711] *Id*.

costs to assist the vendor with hiring qualified workers and improve timeliness of markings. BGE also noted that it hired an additional vendor at the end of 2021. These additional costs for both gas and electric for MYP 2021 and MYP 2022 totaled $1,307,665.00.[712]

Additionally, Mr. Clementson asked the Company to provide additional information about the additional incremental costs paid to Miss Utility associated with Project 61222 Regional Gas Operations Damage Prevention for MYP 2021 and MYP 2022. The Company's response to Staff DR No. 151-04 indicated that "the fees were paid to Miss Utility for tickets that were not marked until after the original due date, which amounted to $536,505.63."[713]

As a result of the additional information, Mr. Clementson stated that with respect to Project 61220 Damage Prevention for 2021 MYP Actual and 2022 MYP Actual, the Company explained that multiple factors contributed to the overspend including the additional costs associated with vendor onboarding and labor shortage. Based on these factors being outside the Company's control, Staff witness Clementson recommended that the Commission provide full recovery of the costs associated with Project 61220 Damage Prevention for both gas and electric for 2021 and 2022.[714]

Regarding Project 61222 Regional Gas Operations Damage Prevention – Facility Locates Miss Utility, the Company explained that the overspend was due to fees paid to Miss Utility for tickets that were not marked until after the due date. Maryland PUA Title 12 "Underground Facilities" statute requires "owner-member (underground facility owner such as a gas company) to mark their facilities within two business days after the day on

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[712] *Id*. at 5-6.
[713] *Id*. at 6.
[714] *Id*.

which a ticket is transmitted to an owner-member or before the selected work date."[715] The Miss Utility law does not provide any type of relief from its requirements to mark in a timely manner so the Company incurred $536,506.63 in additional costs for tickets. Mr. Clementson argued that BGE ratepayers should not be responsible for these overspend costs for Project 61222 for both gas and electric due to the Company's failure to mark facilities as required by Miss Utility law. Therefore, Staff witness Clementson recommends that the Company not be allowed to recover the overspend costs for 2022 MYP Actual ($536,506.63) associated with the fees paid to Miss Utility.[716]

Commission Decision

The Commission finds that BGE's clarifications and responses to Staff witness Clementson's questions regarding the overspending for Project 61220: Damage Prevention for 2021 and 2022 shed light on the multiple external factors which caused the Company to exceed its budget. The Company explained that the additional costs were a result of its transitioning between vendors, as well as labor constraints due to the pandemic. These labor constraints caused the Company to incur additional expense with assisting the vendor with attracting, training, and retaining qualified workers who could assist with timely markings for gas and electric. Based on this clarification, the Commission agrees with Staff witness Clementson's reassessment in his surrebuttal testimony to allow the Company full recovery in the amount of $1,307,66500 for Project 61220: Damage Prevention 2021 and 2022.

[715] *Id*. at 7.
[716] *Id*.

With regard to Project 61222 Regional Gas Operations Damage Prevention – Facility Locates Miss Utility for gas and electric, the Company stated that the overspend was due to fees paid to Miss Utility for tickets that were not marked until after the original due date. Unlike for Project 61220, where the Company explained multiple factors that caused it to exceed budgeted amount, BGE provided no further explanation about mitigating circumstances impacting Project 61222. Therefore, the Commission adopts Staff's recommendation to disallow the overspend costs for 2022 MYP Actual amount of $536,506.63 associated with the fees paid to Miss Utility for tickets that were not marked until after the original date.

2. Substation Equipment Replacement

OPC

OPC witnesses Alvarez and Stephens argued that BGE's substation transformer and circuit breaker replacement programs (Projects 63038 and 67883) totaling $27 million are not cost effective and should be disallowed.[717] Alvarez-Stephens contends that the "Company's substation power transformer and circuit breaker equipment replacement programs ignore the results of functional and diagnostic testing that indicates the equipment is fit for duty."[718] They further noted that replacing substation equipment which has passed functional and diagnostic testing has not proven to deliver any more reliability to justify the incremental costs of such replacements.[719]

To support their argument, Alvarez-Stephens stated that they performed a "risk-informed benefit cost analysis" on both the substation transformer and circuit breaker

[717] Alvarez-Stephens Surrebuttal at 49.
[718] *Id*. at 64.
[719] *Id*.

replacements using BGE's own data on the substation and circuit breaker failure rates.[720] The risk-informed benefit cost analysis results showed that replacing an older substation transformer for a newer one amounted to "$425,000, or only about 1/3 of the average cost to replace a transformer" and that the risk-informed benefits of replacing an older circuit breaker with a new one amounted to $73,000 or about 8% of the average cost to replace a circuit breaker.[721] Based on the analysis, Alvarez-Stephens' argued that "premature replacement of equipment operating safely and reliably, just because it is old, does not justify the practice's cost."[722] They clarified that while older equipment may fail more frequently than newer equipment the difference "is simply insufficiently large relative to the cost of a proactive replacement practice."[723] Overall, Alvarez-Stephens argued that if a piece of substation equipment passes its diagnostic and/or functional tests, it is operating safely and reliably and should not be replaced. Therefore, they recommend that the Commission disallow the full amount of these projects and remove them from MYP II capital spending plans.

<u>BGE</u>

In her rebuttal testimony, BGE witness Wright argued that the Commission should reject OPC's recommendation to disallow certain Substation Transformer Replacement capital costs included for 2021 reconciliation under-recovery amount as well as reject OPC's recommendation to remove capital costs included in the 2024-2026 MYP period.[724] Ms. Wright explained that BGE's substation transformers are aging which requires the

[720] *Id*. at 64-65.
[721] *Id*. at 65.
[722] *Id*.
[723] *Id*. at 67.
[724] Wright Rebuttal Testimony at ii.

Company to spend more in maintenance and cause them to be more susceptible to failure.[725] She stated that the program was developed "to look at a comprehensive set of factors in order to identify transformers that are at high risk of failure in order to prevent in-service failures that could have negative impacts on [BGE's] equipment and distribution system."[726] Ms. Wright noted that the Company has approximately 130 transformers that are at least 50 years old and another 60 transformers that will reach that age in the next 10 years.[727] The Company has analyzed its average power transformer failure rate over the 50-year period between 1969 to 2018. Ms. Wright testified that "[i]n 2018, BGE experienced a significantly higher number of failures with eight transformers failing, five of which were in-service failures."[728] She stated that transformer failure can significantly impact system reliability and causes the substation to be out of normal configuration until it can be replaced, which takes at least six months.[729] While the age of the transformer is a key factor in identifying transformers for replacement, Ms. Wright testified that the Company had several other criteria to select BGE's initial list of transformer replacements for 2021 to 2022.[730] Regarding the age criteria, Ms. Wright noted that the Company currently uses 50 years instead of the industry average of 40 years because of the high quantity of transformers over the age of 50 in service as well as its experience with longer lasting transformers.[731]

[725] *Id*. at 52.
[726] *Id*.
[727] *Id*.
[728] *Id*.
[729] *Id*. at 53.
[730] *Id*. at 54.
[731] *Id*.

Ms. Wright disagreed with OPC witness Stephens' calculations resulting from his risk-informed benefit-cost. Specifically, she pointed out that Mr. Stephens calculated a frequency transformer failure based "on considering 14 transformer failures between 2018–2022 against the total population of transformers." However, BGE does not consider the total population of transformers as part of the proactive replacement program.[732] Ms. Wright clarified that, instead, BGE's proactive replacement program targets transformers that are older than 50 years of age which is currently approximately 130 transformers. Ms. Wright further noted that using BGE's updated transformer amount with the formula presented by Mr. Stephens in direct testimony and assuming no other changes, then the Company's net present value of the program would be $1.4 million instead of $425,000.[733] That means the program generates a value of $1.4 million to BGE customers and this is larger than the cost of the transformer.[734]

Ms. Wright also argued that OPC witness Stephens' recommendation to discontinue BGE's substation oil circuit breaker ("OCB") replacement program was "ill-advised and irresponsible."[735] Ms. Wright explained that BGE began the OCB replacement program "after a failure occurred in 2015 that caused breaker oil to ignite and spray into the substation yard."[736] Ms. Wright contended that "[w]ithout continuing to proactively replace OCBs, BGE expects to see increased failures resulting in customer outages and potential oil spills."[737] She also noted that parts of OCBs are out of production which requires replacement parts to be custom made which leads to greater costs as well as

[732] *Id*.
[733] *Id*.
[734] *Id*.
[735] *Id*. at 55.
[736] *Id*.
[737] *Id*.

increased lead time between order placements and delivery.[738] Last, Ms. Wright stated that witness Stephens used an incorrect number of breakers for BGE in his risk-informed benefit cost analysis. She noted that Mr. Stephens used 2,424 breakers on BGE's system and the more appropriate number to use was 626 which is the remaining number of OCB breakers that the program targets. Using the updated OCB breaker number in Mr. Stephens calculation with all other assumptions equal, Ms. Wright calculated an approximate net present value of $283,000 which exceeds the cost to replace an OCB.[739]

In his surrebuttal, OPC witness Stephens asserted that Ms. Wright adjusted the cost-benefit analyses he completed in a way that indicates prospective replacement benefits are slightly greater than costs.[740] He argued that Ms. Wright's analysis uses only his worst-case scenarios for equipment failure consequences, including both average counts of customers interrupted and the average duration of the associated service interruptions.[741] He stated that by using only worst case scenarios and ignoring average case scenarios, Ms. Wright "overstates benefit estimates (avoided service interruptions) from prospective replacement."[742] He also pointed out that Ms. Wright "assumes best case scenarios for average equipment replacement costs, which understates the estimated costs of the prospective replacement program."[743] Because of these errors in her analysis, Mr. Stephens maintained that Ms. Wright's conclusion that the prospective replacement program delivers benefits greater than costs cannot be relied upon and that his analysis shows that prospective replacement of substation transformers and circuit breakers that have passed

[738] *Id*.
[739] *Id*. at 56.
[740] Alvarez-Stephens Surrebuttal at 55.
[741] *Id*.
[742] *Id*.
[743] *Id*.

their functional and diagnostic tests does not deliver benefits to customers in excess of costs.[744]

Commission Decision

The Commission finds that both the steps advocated for by OPC to test equipment and BGE's proactive approach are reasonable for managing the distribution system. OPC's analysis rightly concludes that functional and diagnostic testing results indicate that the Company's existing substation transformers and circuit breaker equipment passed and are fit for duty presently. This does not negate the fact that BGE's substation transformers and circuit breakers are aging and that some proactive replacements will ensure safe and reliable operations. Here, BGE witness Wright testified that it has identified for its replacement program approximately 130 substation transformers "that are at least 50 years old and another 60 transformers that will reach that age in the next 10 years." She noted that BGE is using a higher than industry average age criteria for its substation replacement program. Similarly, Ms. Wright testified that the Company's oil circuit breakers also are aging, with the majority greater than 50 years in age, which is past the design life of approximately 30 years.[745] But even with the advanced age of BGE's identified population for the replacement substation transformers and OCBs, OPC still maintained its position that, because the equipment passed functional and diagnostic testing, the Company's request for these programs should be disallowed.

The Commission believes a balance needs to be attained between what BGE claims is a reactive or "run-to-failure"[746] approach and aggressive proactive equipment

[744] *Id*. at 55-56.
[745] Wright Rebuttal at 55.
[746] BGE Reply Brief at 38.

replacement. A balanced proactive replacement plan is appropriate under PUA §2-113 to ensure that the utility's operations are in the interest of the public; and promote adequate, economical, and efficient delivery of utility services in the State without unjust discrimination. For the 2021 and 2022 reconciliation period, the Commission rejects OPC's proposed disallowance of these project costs.

3. System Performance Spending

OPC

OPC witnesses Alvarez and Stephens argued that BGE's capital spend for system performance in 2022 by $27.8 million (27.2%) over budget should be disallowed because "system performance spending is discretionary as to timing and extent…"[747] OPC argued that by the time a second major storm hit the BGE territory on August 4, 2022, the Company should have known that it was on track to exceed its 2022 MYP storms budget and it could have taken steps to reduce capital spending on system performance in order to offset excess capital spending related to storms.[748] Alvarez-Stephens contended that instead of reducing system performance spending which is discretionary, BGE accelerated system performance projects that were scheduled later in the MYP period and increased the scope of others.[749] Alvarez-Stephens found that "BGE's failure to reduce discretionary spending in response to known increases in non-discretionary spending to be imprudent."[750]

[747] Alvarez-Stephens Surrebuttal at 24-25.
[748] *Id*. at 25.
[749] *Id*.
[750] *Id*.

BGE

In her rebuttal testimony, Ms. Wright testified that "major storm restoration costs are not forecasted in MYP base distribution rates, and storm costs in general do not and should not have any bearing on the justification of system performance work, which is performed in accordance with safety and reliability standards in order to maintain and improve system safety and reliability."[751] She argued that "storm costs and the system performance budget should not be correlated and that BGE should not be expected to increase or decrease a budget based on something that BGE is unable to control."[752] She also reiterated BGE witness Vahos' direct testimony, which stated "[a]ctual spend is higher or lower than budgeted due to a variety of factors and reasons, including but not limited to inflation, supply chain realities, efficiencies the Company is able to achieve, changing business needs, new regulations or revisions to existing ones, and field conditions."[753] She further noted, as did Mr. Vahos, that "[t]he Company's goal is to complete the necessary work to provide safe and reliable service to our customers, while striving to come in as close as possible to the total budgeted capital and O&M."[754] BGE further argues that there is no reason to tether the Company's system performance project budget to whether the region experiences storms in a given year. [755]

Commission Decision

The Commission agrees with BGE that there is no correlation between major storm costs and system performance work which is needed to meet safety and reliability

[751] Wright Rebuttal (Public) at 39.
[752] *Id*.
[753] *Id*. at 40.
[754] *Id*.
[755] BGE Reply Brief at 39.

standards.[756] The timing, duration and costs associated with major storms are beyond the control of BGE and OPC has not supported its argument that unforeseen and unpredictable storms occurring early in 2022, which increased the Company's major storms budget, should be used to curtail the Company's system performance work and associated budget. The Company noted that "system performance projects take a considerable amount of time to plan and require consideration of multiple factors, including permitting, planned outages, material, and labor availability."[757] Given these factors, the Commission finds that halting the planned system performance work because major storm costs exceed a budgeted amount in any given year could have a wide ranging impact, including potentially interfering with the Company's ability to comply with safety and reliability standards. The Commission may in the future consider a variance test, whereby a percentage over-budget or under-implementation would be deemed imprudent. Based on the foregoing, the Commission rejects OPC's recommendation to disallow the Company's request for $27.8 million for its system performance work. This decision does not abrogate BGE's duty to carefully consider if spends should be deferred into future years if cost overruns are occurring in a category of spend. Failure to adjust Company practices when budgets are being exceeded could lead to future disallowances.

The Commission is aware that, as utilities have sought ways to reduce regulatory lag and obtain more current cost recovery, they have proposed more projected budgets for projects and spending. The Commission understands that projecting costs three and four years in the future is difficult, but that is the challenge utilities undertake when they elect

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[756] *Id.*
[757] *Id.*

to file an MYP. Commission-approved budgets and spending are not aspirational. The Commission expects utilities to manage their operations and spending within the limits the Commission has approved. While the Commission may in the future consider a variance test whereby a specific percentage over-budget or under implementation would be deemed imprudent per se, the record in this case does not support adoption of such a test at this time. Nevertheless, the lack of a specific variance test should not be considered free rein to exceed approved budgets.

4. Leak Prone Pipe ("LPP")

OPC

In his Direct Testimony, OPC witness Hopkins evaluated the prudency of BGE's 2021 and 2022 gas capital investments and found that certain leak-prone pipe investments were imprudent.[758] Specifically, Dr. Hopkins examined Projects 60667 ("BGE Operation Pipeline – STRIDE"), Project 58034 ("Centrally Managed Gas Main Replacements"), and Project 56695 ("Proactive Service Renewals").[759] Dr. Hopkins noted that BGE does not identify specific assets for LPP replacement more than a year in advance.[760] He also noted that BGE does not have specific documents or procedures on how to select Operation Pipeline but uses, according to BGE witness White, "twelve unprioritized factors that may be considered: risk scores for cast-iron pipe using Optimain software; leak history for c[a]st-iron pipes in a region; break history for cast-iron pipes in a region; recent leak or break history; high density paving; poor supply or pressure; state of the existing pressure system; replacement continuity in a particular region; replacement "clean up" to eliminate

[758]OPC Initial Brief at 43.
[759] Hopkins Direct Testimony at 29.
[760] *Id*. at 31.

all remaining targeted outmoded infrastructure in a region; multiple main replacement program jobs in the region; municipal/agency coordination; and diversity in geographic location."[761] He observed that for leak-prone materials that are not actively leaking BGE had adopted the approach to replace these assets over time through Projects 60667 and 58034 which, as noted in the STRIDE II order, would mean replacements would continue until about 2043 if conducted at its current pace.[762]

Dr. Hopkins expressed three primary concerns regarding the prudence of BGE's decision-making for LPP: 1) BGE's informal process means that it does not prioritize risk reduction or the cost-effectiveness of different LPP actions to reduce risk; 2) BGE's failure to do long-term asset planning that reflects climate change policy and market changes increase the risk of imprudently investing in short-lived assets and increasing costs and stranded asset risks; and, 3) BGE's failure to consider non-pipeline alternatives (NPAs) may mean ratepayers are paying more than necessary if BGE used better planning processes.[763] Dr. Hopkins explored each of these concerns outlined above as they pertain to Projects 60667 and concluded that BGE's investments were imprudent in 2021 and 2022 and should be disallowed. Specifically, Dr. Hopkins pointed out BGE admitted that it does not use all outputs of its risk model (called "Optimain") to scope Projects under Project 60667.[764] Based on his analysis using BGE's Optimain software, Dr. Hopkins recommends that the Company "target its [LPP] program to the highest risk miles, whenever cost-effective and feasible, to maximize risk reduction from the program."[765] Regarding cost-

[761] *Id*.
[762] *Id*. at 32.
[763] *Id*. at 32-33.
[764] *Id*. at 34.
[765] *Id*. at 38.

effectiveness, Dr. Hopkins stated that such analysis "examines the level of risk reduction expected from alternative measures in comparison with the cost to deploy these alternatives.[766] From Project 60667, Dr. Hopkins testified that BGE did not consider cost-effectiveness, but wanted to replace all assets under the program regardless of relative risk and cost comparisons.[767] He contended that BGE's approach "does not treat the expenditures of ratepayer dollars with sufficient care, nor does it utilize information on the risk of assets to achieve the most safety benefits possible, as quickly as possible."[768] Given these concerns, Dr. Hopkins concluded that some of BGE's investments are likely imprudent and recommended disallowing recovery for Project 60667 expenses in 2021 and 2022 of $1,531,608 and $1,852,715 respectively.[769]

BGE

In her Rebuttal Testimony, BGE witness White testified that to perform Operation Pipeline work effectively requires considerable planning effort which includes contemplating not only the individual job taking place, but also future work and needs to ensure both the new and remaining system maintain capacity and reliability as the work continues over the years.[770] Ms. White contended that "[d]espite OPC Witness Hopkins' assertions, no single prioritization scheme can drive the selection of work because there are many drivers in creating a plan for replacement. One cannot create a prioritization score to assess the next best neighborhood to replace."[771]

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[766] *Id*.
[767] *Id*. at 39.
[768] *Id*. at 40.
[769] OPC Initial Brief at 44.
[770] White Rebuttal Testimony at 51.
[771] *Id*. at 52.

Ms. White argued that "OPC Witness Hopkins' recommendations would return the Company back over a decade in terms of gas system management policy and philosophy, while jeopardizing BGE's commitment to meeting the needs of its gas customers, improving public safety and reliability, lowering [GHG] emissions, and ensuring regulatory requirements are met."[772] BGE further argued that "[i]t would also be a serious mistake to hold back investments to replace leak prone pipe and aging infrastructure at this time because doing so could put the system at risk of not being able to react quick enough to take advantage of green innovations."[773] BGE maintains that the Company should be permitted to continue to make sound investments in its gas system to ensure that forthcoming innovations can be deployed on BGE's vast distribution system to meet net-zero policies and continue to allow customers to make their own choices when it comes to their energy services."[774]

Commission Decision

The Commission finds that OPC witness Hopkins presented several thoughtful suggestions that the Company should consider in the future for gas system planning and specifically its leak-prone pipes program. The Commission finds that prioritizing risk reduction and cost-effectiveness, taking rapidly changing current and future State and federal policies into consideration, and proactively considering non-pipeline alternatives will be necessary for ensuring that the utility is able to meet long-term system needs and maintain safe and reliable systems. Gas system assets, as noted by Dr. Hopkins, "have multi-decade physical useful lifetimes and are generally depreciated over a comparable

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[772] *Id*. at 40-41.
[773] BGE Initial Brief at 21.
[774] *Id*. at 21-22.

timeframe."[775] The Commission agrees that it is paramount that the utility understand how these assets will be used over time and take into account policy and market force changes that may impact the useful life of the gas assets. While the Commission finds that the Company may be considering some of these measures in its LPP, it can and should do a more comprehensive job of incorporating the concerns presented by OPC.

Given that this is BGE's first MYP reconciliation, the Commission rejects OPC's recommendation for disallowance of expenses for Project 60667 for 2021 and 2022, but cautions that the Commission may consider such variance disallowance recommendations in future MYPs following our review of the "lessons learned" report. Additionally, it is questionable if OPC's cost disallowance is appropriate in this case since a number of the policy documents referred to by OPC to show BGE's planning is improper were released or enacted either in 2021 and 2022, which is the same period as the costs under review.[776] Finally, since the costs OPC proposed to disallow were planning O&M and not capital costs, OPC did not show the capital costs themselves were not proper to serve customers.

N. Performance Incentive Mechanisms ("PIMs")

Pursuant to authorization by the Commission in Order No. 89638, in Case No. 9618,[777] BGE has proposed four Performance Incentive Mechanisms ("PIMs") as part of a larger PIM structure with symmetrical rewards and penalties for the MYP period 2024-2026, consisting of either increased or reduced ROE basis points above or below the authorized electric or gas ROE, subject to an overall cap.[778] BGE proposed that resulting

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[775] Hopkins Direct at 40.
[776] *Id*. at 13.
[777] Case No. 9618, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company, Order No. 89638 (Sept. 29, 2020).
[778] Witness Case Direct at 17-18, Table 2; Frain Direct at 64.

revenue impacts will be reconciled through the proposed Adjustment Rider, with annual filings on PIM performance.[779]l

BGE proposed a PIM based on the number of Customers Experiencing Multiple Interruptions, focused on those who have experienced four or more sustained outages per year for three consecutive years (the "CEMI4-3P PIM").[780] The primary goal of the CEMI4-3P PIM is to reduce the number of such customers by 25% below the 3-year average of 2,084 customers (from 2019-2021).[781] BGE proposed to utilize selective undergrounding, reconductoring with heavier cable, and installation of additional sectionalizing equipment.[782]

BGE proposed a PIM designed to accelerate GHG emissions reductions under three programs: (1) tree planting; (2) fleet electrification; and (3) rooftop solar.[783]

BGE proposed a PIM to accelerate the replacement of existing oil-based circuit breakers ("ROBE") on the electric distribution system with vacuum-based circuit breakers.[784] BGE argued that this will improve reliability, reduce maintenance costs, prevent oil leaks and clean-up costs, and reduce reliance on hard-to-acquire replacement parts for aging equipment. The proposed PIM will incentivize an increased rate of replacement, cutting the replacement schedule from 30 years to 15 years but at increased cost.[785]

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[779] Frain Direct at 68.
[780] Singh Direct at 38-50.
[781] *Id*. at 42.
[782] *Id*. at 45-46.
[783] Case Direct at 22-38.
[784] Apte Direct at 43.
[785] *Id*. at 55-56.

BGE proposed a PIM to reward the increased use of gas main abandonment jobs that utilize ZEVAC units.[786] ZEVAC is a company that manufactures equipment used to capture and re-use natural gas as an alternative to purging natural gas into the atmosphere.

BGE presented cost-benefit analyses in support of its PIM programs.[787] Those analyses concluded that the CEMI4-3P, ZEVAC, and rooftop solar programs were cost effective, while the fleet electrification, tree planting, and ROBE programs were not.[788]

Stakeholders have offered recommendations about BGE's PIM program in its entirety as well as specific recommendations about individual PIM programs. Some stakeholders have also offered alternative PIMs for Commission consideration.

1. Recommendations Regarding BGE's PIM Program Generally

OPC

OPC witness Lane testified that a well-designed PIM should focus on performance areas where a utility lacks an incentive or has a disincentive to achieve a desired outcome.[789] She testified that it is critical that a PIM does not reward the utility for an outcome it already has an incentive to achieve, such as the incentive to invest in new capital to grow its rate base, avoid a penalty, meet an existing regulatory standard, or achieve internal corporate or shareholder goals.[790] She testified that a PIM should also be based on historical baseline data that demonstrates the utility is underperforming as to some desired outcome.[791] She testified that BGE already has a capital incentive to perform most of the work in its proposed PIMs and that the PIMs do not contain any incentive for cost

[786] White Direct at 49-52
[787] BGE Exhibit MDC-2, attached to Case Direct, BGE Exhibit SS-2.
[788] *Id*.
[789] Lane Direct at 14.
[790] *Id*. at 14-15.
[791] *Id*. at 15.

control.[792] She testified that a shared savings mechanism would better align the utility's incentives with those of ratepayers.[793]

Witness Lane testified that BGE's BCAs do not adhere to the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources due to their exclusion of utility performance incentive costs, the costs BGE proposes that customers pay as rewards for completing the PIM goals.[794] She testified that BGE's explanation, that the reward payments are "transfer payments" that do not belong in a BCA and are subject to uncertainty, incorrectly applies the standard and ignores precedent from other jurisdictions that include incentive rewards in the BCA.[795]

<u>*DOD*</u>

DOD witness Gorman testified that BGE's PIM proposals remove the need for rate affordability and efficiency.[796] He recommended that BGE should track the PIM metrics without additional reward.[797]

<u>*IBEW*</u>

IBEW witness Jacobs recommended that the Commission reject BGE's PIM proposals, arguing that adjustments to ROE are an arbitrary system for rewarding BGE for fulfilling its function as a utility.[798] He testified that BGE's proposal for an annual review of its PIM progress would create excessive amounts of work for stakeholders and the

[792] *Id*. at 36-37.
[793] *Id*. at 38.
[794] *Id*. at 33.
[795] *Id*. at 34-35.
[796] Gorman Direct at 18.
[797] *Id*. at 19.
[798] Jacobs Direct at 7-8.

Commission and would entail adjustments to ROE occurring outside of a rate case and in isolation.[799]

Staff

Staff witness Bacalao recommended that the Commission reject all of BGE's proposed PIMs.[800] Mr. Bacalao testified that the structure of BGE's PIM proposals, involving the addition or subtraction of basis points from the authorized ROE, has the effect of multiplying the incentive amount beyond the net benefit generated by BGE's initiatives.[801] He recommended that, should the Commission choose to direct BGE to pursue these incentive mechanisms, the associated metrics should be redesigned to better conform to the benefits targeted for them.[802]

Mr. Bacalao recommended that, should the Commission choose to pursue some or all of BGE's proposed PIMs, the benefit-cost analysis should be recalculated using improved discount rates, with a more rigorous sensitivity analysis that shows the impact of potential changes in the discount rates over time.[803] Mr. Bacalao testified that BGE's benefit-cost analysis for its PIM programs utilized a discount rate for the social cost of carbon emissions that might be unreasonably low given the current interest rate environment.[804] Mr. Bacalao testified that the value of those PIMs falls considerably if a higher discount rate is chosen and that the different programs may need separate discount rates because they present different risk profiles.[805]

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[799] *Id*. at 8.
[800] Bacalao Direct at 50.
[801] *Id*. at 24.
[802] *Id*. at 50.
[803] *Id*.
[804] Bacalao Direct at 33.
[805] *Id*. at 34-41.

BGE Rebuttal

In rebuttal, BGE witness Case testified that BGE produced in discovery its reasoning for an ROE adjustment approach.[806] He also testified that BGE's proposal to review PIM performance metrics as part of each year's annual information filing provides timely transparency and ensures that PIM metrics are approved at the same time as prudency reviews for the associated costs.[807]

Witness Case testified that BGE used a nominal discount rate of 4.55 percent, based on a 2 percent real discount rate adjusted for inflation.[808] He also testified that BGE's social cost of carbon study results consider multiple discount rates but did not explore sensitivities to different discount rates.[809] He testified that BGE used a single discount rate because it was valuing costs and benefits from a societal point of view and because risk assessments were not performed for the programs.[810]

Witness Case testified that Staff supported the concept of using an ROE adjustment as part of a PIM in the workgroup that preceded the Commission's authorization of PIM proposals.[811] He testified that BGE is open to suggestions on other reward structures.[812]

MEA Surrebuttal

MEA Director Pinsky testified that BGE has failed to consult with state agencies like MEA and OPC in developing PIMs that support state policies, as required by footnote 53 of Order No. 89638.[813]

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806 Case Rebuttal at 73.
807 *Id*. at 74.
808 *Id*. at 80.
809 *Id*. at 80-81.
810 *Id*. at 81-82.
811 *Id*. at 72-73.
812 *Id*. at 73.
813 Pinsky Surrebuttal at 8.

Sierra Club Surrebuttal

In surrebuttal, Sierra Club witness Walker testified that he is not arguing that PIMs should only be for business-as-usual functions but that a PIM should measure BGE's ability to improve its core business performance.[814]

Mr. Walker testified that BGE's PIMs fail to align with the Commission's prior directives that: (1) metrics should be designed so they are not met easily; (2) targets will be unique for each utility; (3) interested parties may propose modifications; and (4) a PIM proposal must accelerate the policy goal beyond the current utility's capability.[815] He argued that BGE's proposed PIMs are easily met through business-as-usual progress, without addressing known deficiencies or high priority issues not within BGE's current capabilities.[816]

2. Recommendations Regarding Specific PIM Proposals

a. CEMI4-3P Reliability PIM

OPC

OPC witness Lane testified that the CEMI4-3P PIM does not benefit ratepayers, despite BGE's estimated positive BCA, because BGE's BCA incorrectly fails to account for all capital investments or utility incentives, which bring the BCA below 1.[817] She recommended that the CEMI4-3P be modified to provide only a penalty but possibility of no reward.[818]

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[814] Walker Surrebuttal at 3.
[815] *Id*. at 3-4, citing Order No. 89638 at 4, 12, and 16
[816] *Id*. at 4.
[817] Lane Direct at 59-60.
[818] *Id*. at 61.

Staff

Staff witness Wilson recommended that the Commission reject BGE's proposed CEMI4-3P PIM and instead direct BGE to include in its existing CEMI program plan the analysis of cost effective solutions to address the customers it planned to target with the PIM.[819] He testified that BGE's proposed CEMI4-3P PIM can provide qualitative and quantitative benefits.[820] However, he also testified that the Commission should not approve PIMs incentivizing utilities for performing reliability work to help meet or exceed COMAR reliability standards, which are already regulatory requirements.[821] He also testified that BGE's proposed reward structure sets unreasonably low baseline standards, below BGE's 3-year average, and would offer excessively large rewards to BGE, well in excess of the estimated costs.[822]

Staff witness Bacalao recommended that the Commission reject BGE's CEMI4-3P PIM because BGE is already expected to perform reliability work without the need for additional financial incentives.[823]

BGE Rebuttal

In rebuttal, BGE witness Singh testified that CEMI is a distinct metric from the existing SAIFI and SAIDI regulatory requirements and highlights customer specific reliability experience, as opposed to system-wide outages, in order to pinpoint local repeat reliability issues.[824] He testified that BGE could reasonably achieve best-in-class SAIFI

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[819] Wilson Direct at 12.
[820] *Id*. at 7.
[821] *Id*. at 10-11.
[822] *Id*. at 9-12.
[823] Bacalao Direct at 30.
[824] Singh Rebuttal at 4.

performance while missing all CEMI4-3P targets.[825] He testified that BGE set the reward/penalty levels in order to account for significant year-to-year variation in the metric, with the proposed penalty cutoff being BGE's internal targeted performance levels.[826] Mr. Singh testified that the CEMI4-3P PIM is exactly what Staff proposed in the Phase II report on PIMs, within Case No. 9618.[827] He testified that the BCA for the CEMI4-3P has a nominal 2.1:1 benefits-to-cost ratio.[828]

Witness Singh testified that BGE's proposed vegetation management program was premised on significant improvements in SAIDI and SAIFI metrics in the Bowie feeder system after the implementation of vegetation trimming in that area, and BGE expects similar results from the proposed expansion of that program.[829] He testified that he agreed with Staff witness Wilson that a BCA should be provided at the end of the program.[830] He testified that BGE will provide a preliminary BCA as well as a reliability study that will be monitored through the third quarter of 2024, with a final BCA by the end of first quarter 2025.[831] He testified that BGE expects high initial costs, from removing a large volume of overhanging tree limbs and strategic trees, followed by lower costs to maintain the program.[832]

BGE witness Case testified that the Commission should separately decide on the metric and the appropriate reward/penalty structure.[833]

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[825] *Id*. at 5.
[826] *Id*. at 6.
[827] *Id*. at 6-7.
[828] *Id*. at 7.
[829] *Id*. at 9.
[830] *Id*.
[831] *Id*.
[832] *Id*. at 10.
[833] Case Rebuttal at 98-99.

Staff Surrebuttal

In surrebuttal, Staff witness Wilson testified that he continued to support BGE's efforts to improve its CEMI4-3P performance through the implementation of its existing CEMI program but not through the proposed PIM.[834]

Witness Wilson testified that he approves of trimming as a corrective action near poor performing feeders[835]. He testified that, should the Commission approve the program, it should require BGE to provide a BCA for Staff's review and approval prior to implementation.[836]

Witness Wilson testified that by rejecting BGE's proposed CEMI4-3P PIM, BGE can still perform the additional work in its existing CEMI improvement work plan and recover the associated costs there.[837] He also testified that BGE's proposed penalty levels do not show a credible risk for BGE.[838]

b. Greenhouse Gas PIM

MEA

MEA Director Pinsky recommended that the Commission reject BGE's proposed GHG PIM.[839] He testified that it is inappropriate for ratepayers to pay a return to BGE for improvements to its own buildings and vehicles.[840] He testified that there is already a robust tree-planting program run by the State that does not have an impact on ratepayers.[841]

[834] Wilson Surrebuttal at 2.
[835] *Id*.
[836] *Id*.
[837] *Id*. at 2-3.
[838] *Id*. at 3-4.
[839] Pinsky Direct at 5.
[840] *Id*. at 8-9.
[841] Pinsky Direct at 9.

Sierra Club

Sierra Club witness Walker testified that BGE's GHG PIMs are not a measure of methane emissions reductions in BGE's core operations but rather merely expenditures made to outside vendors.[842] He testified that BGE should instead seek to improve its operational performance.[843]

OPC

OPC witness Lane testified that BGE seems to have selected its GHG programs without consideration of the cost of GHG emissions reductions and whether these projects are the most cost-effective or efficient way to reduce GHG emissions.[844] She testified that, over the course of the rate-effective period, BGE forecast the GHG projects to reduce BGE's total operational emissions by less than one percent.[845]

Witness Lane testified that BGE's proposed Fleet Electrification and Tree Planting programs are not cost-effective even before consideration of a performance reward to BGE.[846]

Witness Lane testified that the Tree Planting program is not a reliable means for offsetting GHG emissions.[847] She testified that the Commission should also reject BGE's proposed tree planting budget for the same reason.[848]

Witness Lane testified that the proposed fleet electrification program provides no net-benefits to ratepayers and requires no additional incentive for BGE to pursue.[849] She

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[842] Walker Direct at 6-7.
[843] *Id*. at 7.
[844] Lane Direct at 41.
[845] *Id*. at 42-43.
[846] *Id*. at 4-5 and 45.
[847] *Id*. at 6 and 46-47.
[848] *Id*. at 48.
[849] *Id*. at 48-49.

testified that the program has a high cost per ton of GHG emissions reduced, the highest cost among all of BGE's GHG proposals.[850]

Witness Lane testified that the Rooftop Solar program is cost-effective and that the Commission should approve the associated capital budget but deny the PIM because BGE has a capital incentive to pursue the project and is already planning to retrofit its facilities with increased solar generation, for which costs were approved in its last rate case.[851]

Staff

Staff witness Bacalao recommended that the Commission reject BGE's Tree Planting program, as part of its GHG reduction PIM.[852] Mr. Bacaleo testified that this type of program is outside BGE's core competency as a public utility, as reflected in its proposal to rely entirely on outside service providers, would be a distraction from BGE's core business activities, and would be difficult to allocate to ratepayers.[853]

BGE Rebuttal

In rebuttal, BGE witness Case testified that there is no regulatory requirement that PIMs must relate to activities that BGE should be doing in the normal course of business.[854]

Witness Case testified that the Commission has not explicitly required PIMs to have a BCA greater than 1.0, only that they "show measurable benefits," and that the Commission has historically approved EmPOWER MD programs where some elements of the program have a BCA below 1.0 but the overall portfolio is cost-effective.[855] He also testified that, despite certain programs having BCAs less than 1.0, BGE believes benefits

[850] *Id*. at 50.
[851] *Id*. at 7 and 51-52.
[852] Bacalao Direct at 26.
[853] *Id*.
[854] Case Rebuttal at 71.
[855] *Id*. at 69-70.

exceed costs for each PIM proposed.[856] He also testified that earning the authorized return on investments is not an incentive and not consistent with performance-based rates.[857]

Witness Case testified that including the PIM reward in the BCA calculation would be inappropriate because the reward/penalty is uncertain and because the PIM is a transfer payment that does not belong in the societal cost test.[858]

Witness Case testified that OPC witness Lane does not consider the amount of work that needs to be executed to meet the targeted performance levels, for which the PIM provides inducement.[859]

Witness Case testified that, although the BCA for the tree planting program is below 1.0, there are certain sensitivities that could push it above 1.0.[860] He also testified that planting trees as a solution to GHG emissions is supported by Maryland's Tree Solutions Now Act of 2021.[861] He also testified that BGE has an ongoing partnership with the Maryland Department of Natural Resources and other programs to plant trees, which have provided BGE with the necessary experience.[862]

Witness Case testified that, although the BCA for the electrification program is less than 1.0, it might turn out to be cost-effective.[863] He testified that BGE could choose to move forward with the program in the event the Commission rejects the associated PIM.[864]

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[856] *Id*. at 70.
[857] *Id*.
[858] *Id*. at 78.
[859] *Id*. at 84.
[860] *Id*. at 87.
[861] *Id*.
[862] *Id*. at 89.
[863] *Id*. at 91.
[864] *Id*. at 92.

Witness Case testified that its Rooftop Solar program does not fall under the prohibition on utilities owning generation because the proposed program would merely offset BGE's own load from its buildings and fleet, with excess generation added to the grid like any net-metering customer.[865]

MEA Rebuttal

In rebuttal, MEA Director Pinsky testified that MEA does not support ratepayers paying an elevated rate of return to BGE for meeting CSNA requirements or for planting trees.[866]

OPC Surrebuttal

OPC witness Lane testified that BGE's tree planting, fleet electrification, and rooftop solar initiatives are already occurring without a performance incentive.[867]

Witness Lane testified that BGE's decision to combine four performance metrics into a single PIM is illogical, and each metric should be considered separately as an individual PIM proposal.[868]

Witness Lane testified that tree-planting is not a monopoly service that should be funded by ratepayers and does not provide any utility system benefits.[869]

c. Removal of Oil-Based Equipment PIM ("ROBE")

OPC

OPC witness Lane recommended that the Commission deny BGE's proposed ROBE PIM because it has not been shown to be cost-effective even before consideration

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[865] *Id*. at 95.
[866] Pinsky Surrebuttal at 7and 9.
[867] Lane Surrebuttal at 15.
[868] *Id*. at 10-11.
[869] *Id*. at 16-17.

of a performance reward to BGE and because BGE already has an incentive to avoid penalties and fines associated with oil leaks.[870] She recommended that the Commission also reject BGE's proposed expenditures to accelerate replacement of aging oil-based circuit breakers for the same cost-benefit reasons and because the majority of benefits accrue to BGE and not ratepayers.[871]

Staff

Staff witness Austin recommended that the Commission reject BGE's proposed ROBE PIM in favor of BGE's current Removal of Oil-Based Equipment Program.[872] He testified that the estimated revenue from ratepayers required by this proposed PIM far exceeds the quantifiable benefits and that the primary benefit would accrue to BGE in the form of reduced future clean-up costs that may or may not be recoverable in rate base.[873] He also recommended disallowance of the $4.1 million that would be required for the accelerated distribution substation oil circuit breaker replacement program, with any significant variance of expenditures above $8.1 million - the amount estimated to be required to maintain the existing schedule - be considered for disallowance.[874]

Staff witness Bacalao recommended that the Commission reject BGE's ROBE PIM.[875] He testified that the proposed structure, increasing or decreasing ROE, would unfairly impact all customers regardless of whether they benefit from the program.[876] He

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[870] Lane Direct at 7 and 53-54.
[871] *Id*. at 7-8 and 56.
[872] Austin Direct at 4 and 123.
[873] *Id*. at 122.
[874] *Id*. at 123.
[875] Bacalao Direct at 27.
[876] *Id*.

testified that the costs and benefits of the program should accrue entirely to electric service customers, with no reward or penalty applied to BGE.[877]

<u>BGE Rebuttal</u>

In rebuttal, BGE witness Wright testified that there is some risk to BGE that lead times and material costs for circuit breakers, as well as availability of resources for design, engineering, and construction, could impede its ability to meet its ROBE targets.[878]

BGE witness Case testified that, while the ROBE program has a BCA below 1.0, that projection is subject to sensitivities (such as an increased rate of breaker failures beyond the historic rate) that could result in it being cost-effective.[879] He also testified that projects like the ROBE proposal are historically socialized across all electric customers, regardless of whether they are directly affected by the initiative.[880]

<u>OPC Surrebuttal</u>

In surrebuttal, OPC witness Lane testified that BGE has not demonstrated that failure rates will be higher than historical rates, without which condition the program will not be cost effective.[881]

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[877] *Id*.
[878] Wright Rebuttal at 57.
[879] Case Rebuttal at 96.
[880] *Id*. at 97-98.
[881] Lane Surrebuttal at 20.

d. ZEVAC PIM

Sierra Club

Sierra Club witness Walker testified that the use of ZEVAC is neither novel nor risky, and the PIM solely rewards BGE for purchasing and using the equipment.[882] He testified that this would not be a good measure for emissions reductions.[883]

OPC

OPC witness Lane recommended that the Commission deny BGE's proposed ZEVAC PIM, arguing that BGE should not receive a financial reward merely for purchasing equipment or using equipment it has already purchased.[884] She recommended that the Commission require BGE to utilize the ZEVAC machine as proposed, but without any special financial reward or penalty, and to track the avoided GHG emissions associated with purging operations and ZEVAC operations.[885] Ms. Lane testified that BGE has an obligation to ratepayers to utilize the ZEVAC machines to the extent possible to maximize the value of the equipment and should not need a PIM to encourage it to do so.[886]

Staff

Staff witness Bacalao recommended that the Commission reject BGE's ZEVAC PIM because the proposed benefits are unrelated to the physical volume of emissions avoided and result in a distorted link between performance and incentive.[887] He testified

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[882] Walker Direct at 5.
[883] *Id*.
[884] Lane Direct at 8 and 57-58.
[885] *Id*. at 8 and 58.
[886] Lane Surrebuttal at 21-22.
[887] Bacalao Direct at 28-29.

that BGE should already be expected to make such investments when they benefit the customer base.[888]

BGE Rebuttal

In rebuttal, BGE witness Case testified that it is irrelevant whether BGE voluntarily purchased and knew of the ZEVAC machine already: the only question is whether BGE's proposal incentivizes BGE to use ZEVAC on an accelerated basis.[889] He testified that BGE has no obligation to use the ZEVAC.[890]

BGE witness White testified that it is irrelevant whether a proposed PIM relates to day-to-day operations or is novel.[891] She testified that the use of ZEVAC has not become an industry standard practice yet, nor is it a regulatory requirement, and BGE only began using it for some projects in 2022.[892] She testified that the PIM will help incentivize BGE to reach 100% utilization by 2026.[893]

3. Alternative PIMs Proposed

Two parties, OPC and Sierra Club, proposed alternative PIMs.

OPC

OPC witness Lane recommended that the Commission modify its directive from Order No. 89638 that only utilities may propose PIMs.[894] She testified that utilities are only proposing PIMs for activities they already have an incentive to achieve and that non-utilities may be able to propose PIMs that yield better results.[895]

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[888] *Id*. at 29.
[889] Case Rebuttal at 100.
[890] *Id*. at 101.
[891] White Rebuttal at 6.
[892] *Id*. at 7.
[893] *Id*.
[894] Lane Direct at 8.
[895] *Id*. at 8-9 and 66-67.

BGE Rebuttal

In rebuttal, BGE witness Case testified that Commission Order No. 89638 was clear that only the utility filing the rate case may propose a PIM but that intervening parties may propose modifications.[896]

a. OPC PIM Proposal 1 - Non-Pipes Alternatives

OPC

OPC witness Lane recommended that BGE adopt a PIM for non-pipes alternatives ("NPA").[897] She testified that an NPA is a collection of measures, commonly located at end-use customers' facilities, that meet anticipated system reliability needs without new gas infrastructure investments.[898] She testified that NPAs could include temporary supply, energy efficiency, electrification, and demand response programs.[899] She testified that BGE has a clear disincentive to pursue NPAs because they displace capital investment.[900] She recommended that the Commission direct BGE to develop an NPA PIM for its next rate case, possibly modeled on the programs utilized by New York utilities and structured as a shared-savings PIM.[901]

BGE Rebuttal

In rebuttal, BGE witness White testified that a performance metric based on NPAs does not make sense because Maryland has not chosen a path for preventing climate change and managing its future energy needs.[902]

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[896] Case Rebuttal at 75.
[897] Lane Direct at 61-62.
[898] *Id*. at 62.
[899] *Id*.
[900] *Id*. at 62-63.
[901] *Id*. at 63.
[902] White Rebuttal at 85-86.

OPC Surrebuttal

In surrebuttal, OPC witness Lane testified that, regardless of unknowns about Maryland's path to addressing climate change, reductions in natural gas will have an important role in meeting GHG reduction goals.[903] She testified that an NPA PIM would focus on performance areas where BGE lacks an incentive or has a disincentive to achieve a desired outcome.[904]

b. OPC PIM Proposal 2/Sierra Club PIM Proposal 1 - Lost and Unaccounted-for Gas

OPC and Sierra Club both proposed alternative PIMs based on a lost-and-unaccounted-for gas ("LAUF") metric.

OPC

OPC witness Lane recommended that BGE adopt a PIM for lost and unaccounted-for gas ("LAUF").[905] She testified that LAUF is the difference between the gas injected into a distribution system and the gas measured at customers' meters.[906] She recommended the Commission approve a PIM based on two outcomes: LAUF gas emissions and cost per ton of CO2e, with the goal of incentivizing BGE to reduce gas leakage at the lowest cost.[907]

Sierra Club

Sierra Club witness Walker also recommended an alternative PIM based on LAUF.[908] He testified that BGE has been significantly worse than the industry average in most years from 2013-2022.[909] He recommended that BGE should be required to achieve

[903] Lane Surrebuttal at 23.
[904] *Id*. at 23-24.
[905] Lane Direct at 61-62.
[906] *Id*. at 64.
[907] *Id*. at 64-65.
[908] Walker Direct at 11-12.
[909] *Id*. at 12.

an annual reduction of 0.5% in lost gas percentage until it reaches, at most, the industry average, with financial penalties in future years if BGE cannot beat the industry average.[910]

BGE Rebuttal

In rebuttal, BGE witness Case testified that LAUF is not a good performance metric because most of the factors that impact LAUF have nothing to do with GHG emissions and are often "accounting" issues.[911] He testified that the PIM working group did not come to a consensus on the possibility of a LAUF PIM.[912] He testified that BGE already reports its LAUF on a monthly basis.[913]

BGE witness White testified that LAUF can be related to leaks, but it also is related to other factors like temperature and pressure correction, metering accuracy, and theft of energy.[914] She quoted a 2017 PHMSA report that "LAUF gas is not a valid proxy for either unknown leak volume or methane emissions."[915] She also testified that different utilities are affected by factors differently, making comparison between utilities difficult.[916]

Sierra Club Surrebuttal

In surrebuttal, Sierra Club witness Walker testified that, while he had not appreciated BGE's concerns regarding fitter leaks, he found BGE's suggestion to simply remove fitter leaks from the data unreasonable because they are caused by tracked causes, including corrosion.[917]

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[910] *Id*. at 12-13.
[911] Case Rebuttal at 102.
[912] *Id*. at 103.
[913] *Id*. at 104.
[914] White Rebuttal at 20.
[915] *Id*. at 20-21.
[916] *Id*. at 20.
[917] Walker Surrebuttal at 8-9.

c. Sierra Club PIM Proposal 2 - Hazardous Gas leaks

Sierra Club

Sierra Club witness Walker recommended, as an alternative PIM, that a better measure of BGE's reduction in GHG emissions could be based on reductions in hazardous gas leaks.[918] He testified that he reviewed BGE's hazardous leak metrics from 2013-2022 and concluded that the numbers have been increasing over the past 5-6 years, after a period of decreasing leaks and despite considerable STRIDE investment in its distribution network.[919]

BGE Rebuttal

In rebuttal, BGE witness White testified that Sierra Club's proposed gas leak metric would not make a good PIM.[920] She testified that BGE currently tracks hazardous leaks according to a graded standard that considers various factors and does not necessarily prioritize the volume of gas leakage but focuses on whether the leak poses an immediate safety risk to persons or property.[921] She also testified that many of the factors that drive the number of leaks are outside BGE's control.[922]

She testified that the number of leaks should decrease with BGE's replacement of its existing low-pressure gas system.[923] She testified that BGE performs gas leak surveys over a three-year period, which results in variation across its service territory depending on

[918] Walker Direct at 7-8.
[919] *Id*. at 8-10.
[920] White Rebuttal at 9-10.
[921] *Id*. at 9.
[922] *Id*.
[923] *Id*.

the condition of the infrastructure in the area surveyed in a given year.[924] She testified that BGE already reports on leak repairs in its annual PHMSA report.[925]

She testified that Sierra Club witness Walker's analysis of BGE's gas system leaks over time is flawed because it did not account for the changed reporting methods for "fitter leaks" because witness Walker used data from PHMSA and not the data produced by BGE in his analysis.[926] She testified that fitter leak repairs are typically above-ground repairs related to plumbing or meter work and are not on the targeted aged infrastructure assets BGE is replacing through STRIDE and other programs.[927] She testified that these leaks only began being reported in 2018, and they are often potentially hazardous due to proximity to customer homes.[928]

She testified that including fitter leaks in witness Walker's year-to-year analysis incorrectly compares non-alike data because fitter leaks only appear in the data after 2018.[929] She testified that, when correcting for this issue with the data, the trend of leaks per mile by grade has been declining since at least 2016.[930] She testified that witness Walker's observations of increases in leak repairs in certain cause categories are, however, correct, but she argued that it is difficult to draw conclusions from that data because PHMSA definitions for Pipe/Weld/Joint failure causes have changed during the period under analysis, which is not accounted for in the analysis.[931]

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924 *Id*. at 9-10.
925 *Id*. at 10.
926 *Id*. at 12.
927 *Id*. at 12-13.
928 *Id*. at 13.
929 *Id*.
930 White Rebuttal at 13-14.
931 *Id*. at 16-17.

Sierra Club Surrebuttal

In surrebuttal, Sierra Club witness Walker testified that his proposed hazardous leak metric will advance state policy goals by measuring reductions in direct emissions, show measurable benefits to customers in terms of methane emissions reductions as well as safety and reliability, and contain trackable public data that can be used to benchmark against peer utilities.[932] He testified that, although they are not identical, hazardous leaks involve more methane release than less hazardous leaks.[933] He recommended that hazardous leaks be measured on a rolling three-year basis, to account for BGE's three-year survey practices.[934]

Commission Decision

In Order No. 89638, part of Case No. 9618, the Commission authorized public utilities to propose Performance Incentive Mechanisms ("PIMs") as a means of incentivizing utilities to pursue state policy goals. The Commission's hope was that PIMs could promote utilities to engage in publicly-beneficial activities that were not already adequately incentivized by the existing utility revenue model. The Commission stated in Order No. 89638 that any proposed PIM must be (1) tethered to a recognized State policy; (2) accelerate the policy goal beyond the current utility's capabilities; (3) show measurable benefits to ratepayers; and (4) contain metrics that show baseline data over the specific timeframe.[935]

[932] Walker Surrebuttal at 6.
[933] *Id*. at 7.
[934] *Id*.
[935] Order No. 89638 at 16.

The Commission finds that BGE's proposed PIM program is not likely to lead to reasonable rates and is denied. The Commission is deeply concerned at the overall reward/penalty structure, utilizing adjustments to ROE, which is detached from the value that the proposed PIMs are projected to provide to ratepayers. Although the question of whether the PIMs will succeed and how much return BGE may earn depends on future information, the projections provided in the record strongly indicate that the cost of the proposed PIMs (when including the possible reward) is in excess of the value those programs would provide to ratepayers. The entire PIM program therefore fails to meet the third requirement identified in Order No. 89638. Although BGE has indicated a willingness to explore other structures, the record contains no available alternative, and the Commission declines to create a new PIM structure from the bench, without participation of all appropriate stakeholders.

The Commission is also concerned that BGE's specific proposed PIMs concern programs that are already aligned with BGE's existing profit incentives. Those programs therefore fail the second requirement of Order No. 89638 of accelerating the policy goal beyond the utility's capabilities. Where the primary mechanism for meeting a policy goal is the investment of more capital or other ratepayer funds, rather than new approaches or efficiencies that are not currently incentivized by traditional ratemaking, such a goal is within the utility's capabilities for purposes of Order No. 89638.

Regarding the proposals of alternative PIMs made by other parties, the Commission stated in Order No. 89638 that non-utilities may not currently propose PIMs. The Commission declines to entertain non-utility PIM proposals in this case, and those proposals are rejected. Nevertheless, the Commission is persuaded that non-utility proposals may be able to unlock public policy and ratepayer benefits that utilities might not consider. Going forward, the Commission will allow non-utilities to propose PIMs in future rate cases. Further, in support of the Commission findings in Order No. 89226 that "MRPs may be well suited to pair with PBR's [Performance Based Rates]," and that "aligning state policy goals and utility rate increases is an important objective," advancing PBRs and PIMs in future rate proceedings will be a topic addressed in the MYP lessons-learned proceeding.[936]

Underlying BGE's PIM programs are proposed capital and operating expenses for completing those programs (setting aside the PIM reward/penalty structure). The Commission rejects the associated costs for the CEMI4-3P, GHG[937], and ROBE[938] PIMS, finding that they are not cost-effective or are at best marginally cost-effective. Additionally, the Commission is concerned at the expansion of some portions of the GHG PIM into areas not traditionally related to utility operational performance and over which the Commission has limited expertise and authority.

The Commission approves the proposed operational costs for the ZEVAC program, although not the PIM itself, finding that it may be cost effective and supports the strong public policy position in Maryland and nationally toward minimizing gas releases.

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[936] Case No. 9618*, In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*, Order No. 89226 (Aug. 9, 2019) at 55 and 57.

[937] No party provided a downward revenue requirement adjustment for BGE's Rooftop Solar program. BGE witness Case refers parties to BGE witness Vahos direct testimony which claims the values are located within Real Estate and Facilities Projects. S*ee* Vahos Direct at 50 and 51. There does not appear to be an explicit line item for the rooftop program within this category. Therefore, the values used to derive the adjustment that are the yearly budget come from Table 4 on page 48 of the Brattle study in MDC-2 ($2.5 million - 2023, $7.5 million - 2024, 2025, and 2026). Installed MWs by year were used to represent plant in-service date. The costs were allocated between gas and electric revenue requirements using the same allocation as OPC witness Effron for fleet electrification. S*ee* Effron Surrebuttal Exhibit DJE-6, Schedule B-2 Electric, Sources (E).

[938] The Commission will permit BGE's budget for the circuit breaker replacement program without the ROBE program.

Moreover, the Commission encourages the continued use of the ZEVAC equipment any time such use is appropriate and cost effective.

O. ELECTRIC VEHICLE PROGRAMS

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.[939] BGE is seeking to recover EV program costs in this rate case for its Phase 1 EV program. It is also seeking to recover forecasted costs for a new Phase 2 EV program and for an electric school bus pilot program.

1. Phase 1 EV Program

BGE

BGE's Phase 1 EV Program costs are supported by a BCA sponsored by BGE witness Warner. Mr. Warner testified that he applied the EV-BCA developed by the EV-BCA working group and adopted by the Commission.[940] He testified that he performed five separate assessments, as defined by the methodology of the EV-BCA: (1) a quantification of the cost effectiveness of utility EV programs resulting from impacts on the utility system, host customers, and society; (2) the same methodology but applied market-wide to quantify societal benefits; (3) an analysis of aggregate non-participating-ratepayer-impact, such as externalities and costs; (4) the same but considering only the

[939] Case No. 9478, Order No. 88997 at 44, n. 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").
[940] Warner Direct at 5.

monetized impact on utility bills for customers; and (5) an examination of other strategic considerations.[941]

Witness Warner testified that, under his analyses, all offerings as well as the portfolio of offerings, were found to have a positive net present value and negative dollar-amount impact (indicating a favorable result for ratepayers).[942]

OPC

OPC witness Lane testified that BGE's EV BCA adheres to the framework approved by the Commission except for its application of the MD EV-JST in performing a combined BCA on the Charger Rebate (a rebate to customers installing an EV charger) and the HCI (a rebate to customers for sharing charging data) and a separate combined BCA on the Charger Rebate, the TOU (for customers participating in time-of-use rates), and the HCI.[943]

Witness Lane testified that BGE's decision to combine these programs into a single BCA excludes a large number of customers from analysis, for example the 48 percent of customers that received the charger rebate but did not participate in the TOU.[944]

Witness Lane also testified that the TOU rate and HCI program were designed to modify charging behavior for existing EV users and should not be lumped in with customers receiving an incentive to install a new EV charger.[945] She testified that the programs should have been assessed separately.[946]

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[941] *Id*. at 5-6.
[942] *Id*. at 7.
[943] Lane Direct at 94-97.
[944] *Id*. at 97.
[945] *Id*. at 99.
[946] *Id*. at 97-98.

Witness Lane testified that BGE failed to include in its BCA the costs associated with the purchase and installation of the Level 2 chargers in the charger rebate program, although the Commission's approved BCA methodology includes participant costs.[947] She testified that when the full cost of the charger (net of the rebate) is added, these offerings are no longer cost-effective, but only if the incremental cost of an upgraded charger is added do they remain cost-effective.[948]

Witness Lane recommended the Commission require BGE to submit a corrected BCA.[949]

Staff

Staff witness McAuliffe testified that BGE witness Warner's BCA complied with the updated methodology for EV-BCA's approved by the Commission in Case No. 9478.[950] He testified that Mr. Warner's results are largely influenced by his projection of the number of EVs on the road but do not provide specific information on the impact of utility offerings on EV adoption.[951] He testified that Mr. Warner's attempt to address this, by reference to the number of EVs a charger can support in a given year, overstates BGE's impact on EV adoption and should therefore not be used as any definitive assessment of BGE's EV portfolio.[952] He recommended that the Commission allow BGE to move its EV costs into rates, with prudency determined at the conclusion of the MYP rate-effective period, as the Commission has done previously in Case Nos. 9645 and 9655.[953]

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[947] *Id*. at 100-101.
[948] *Id*. at 103-104.
[949] *Id*. at 104.
[950] McAuliffe Direct at 65.
[951] *Id*. at 68.
[952] *Id*. at 69.
[953] *Id*.

BGE Rebuttal

In rebuttal, BGE witness Warner testified that the market-wide test is defined to look at the benefits of EVs overall, not utility program cost-effectiveness.[954] He testified that, while the EV-BCA did not define specific inputs for the BCA model, the EV-BCA framework provided guidelines to prioritize where inputs should come from while allowing flexibility to account for continually evolving knowledge and the details of specific offers and programs.[955] He testified that witness McAuliffe is correct that the model is sensitive to inputs and that there is limited research connecting the availability of public charging with EV usage.[956] He testified that he relied on proxies, such as DOE's National Public In Electric Vehicle Infrastructure Analysis, which recommended one public DCFC port per every 784 EVs, and a 2021 study from the International Council on Clean Transportation, which recommended 80 to 145 EVs per charging port in the 2025-2030 timeframe.[957] He testified that, given the public concerns about the availability of charging stations, he used 120 EVs per port in his analysis.[958] He testified that witness McAuliffe did not present any alternative methodology or sources.[959]

BGE witness Warner testified that attempting to perform a BCA on individual program elements would not reflect how the programs are actually used: for example, under BGE's programs there is no scenario where a customer received a charger rebate without participation in the HCI program.[960] He testified that he attempted to model the

[954] Warner Rebuttal at 2-3.
[955] *Id*. at 3-4.
[956] *Id*. at 4-5.
[957] *Id*. at 5.
[958] *Id*.
[959] *Id*. at 5-6.
[960] *Id*. at 7-8.

programs in the manner in which they would actually be used.[961] He testified that attempting to artificially separate programs into stand-alone elements would result in either costs or benefits being ignored.[962] He testified that witness Lane's concern that some participants are ignored in his analysis is false, that they are addressed in sub-groups of the analysis.[963] Regarding the costs of Level 2 chargers, he testified that this question was addressed in the MD EV-BCA methodology, which does not include charger costs where the customer already owns a charger, because the analysis is only looking at modifying existing charging behaviors.[964]

OPC Surrebuttal

In surrebuttal, OPC witness Lane testified that there are some customers who receive only a charger rebate because the HCI program was not implemented until early 2022, after BGE issued all of its approved charger rebates.[965] Regarding the inclusion of charger costs, she testified that the rebate program assumed that customers did not have an eligible level 2 charger, thus the entire customer cost of the charger (net the rebate) should be included in the BCA.[966]

Staff Surrebuttal

In surrebuttal, Staff witness McAuliffe testified that BGE witness Warner's testimony confirms the lack of research in this area and subjectivity of the BCA.[967] He

[961] *Id*. at 8.
[962] *Id*.
[963] *Id*. at 8-9.
[964] *Id*. at 9.
[965] Lane Surrebuttal at 28.
[966] *Id*. at 30-31.
[967] McAuliffe Rebuttal at 27.

recommended that the BCA not be used to make definitive assessments of the EV programs.[968]

<u>Commission Decision</u>

The Commission notes the continued disagreement between the parties regarding the application of the BCA methodology that was approved by the Commission in Case No. 9478. The EV Workgroup is directed to consider and address these disagreements and provide a recommendation by June 3, 2024. The EV BCA is a critical tool to examine the effectiveness of utility programs for EV infrastructure deployment balanced against the costs and ratepayer impact of those programs. The Commission seeks an EV BCA to guide those competing needs.

Given the fluid nature of the EV BCA methodology and the alleged subjectivity thereof, the Commission makes no precedential finding as to the BCA of Phase 1 programs at this time.

Phase 1 costs are approved and may be moved into the revenue requirement, with prudency to be determined at the end of the rate-effective period.

2. Phase 2 EV Program and Electric School Bus Pilot Program

<u>BGE</u>

BGE has requested to include costs for a proposed Phase 2 EV program – including expansion of its existing public charger network and other EV programs related to fleet and mass transit investment, public charging, multifamily charging, and grid management strategies – and an electric school bus pilot in the rates that will result from this case.[969]

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[968] *Id*.
[969] Case Direct at 50.

Simultaneously, the Commission is considering those programs in Case Nos. 9478 and 9696.

Stakeholder comments concerning BGE's Phase 2 EV program and electric school bus pilot program focused on three questions: (1) Should these programs be eligible for recovery in this rate case? (2) How should non-capital expenditures be recovered from ratepayers? And (3) should BGE be able to put the costs of public charging stations into rate base?

a. Whether Phase 2 EV and Electric School Bus Pilot Costs Should Be Recoverable in this Case

OPC

OPC witness Lane recommended that the Commission reject BGE's application to include its Phase 2 costs in this rate case and instead consider cost recovery and budgets within a single subsequent proceeding because it would ensure consistent determination of key issues.[970] OPC witness Lane testified that BGE's proposal to include EV costs in rates when it does not have a final EV budget is not "just and reasonable."[971]

Witness Lane testified that, before approving an extension of BGE's EV pilot programs, the results of those pilots must be examined to determine if further support or modifications are in the best interest of ratepayers.[972] She testified that the Commission, in Order No. 88997, required completion of a final EV program report by March 1, 2024, with a subsequent legislative hearing in May 2024.[973] She testified that, in the same Order, the Commission determined that, after the pilot study concludes, customers enrolled in a

[970] Lane Direct at 72.
[971] *Id*. at 73-74.
[972] *Id*. at 77.
[973] *Id*. at 76.

pilot program or rate offering can elect to continue in that posture pending a final decision by the Commission to extend or expand the applicable program.[974]

Witness Lane testified that there are numerous policy discussions that should occur in advance of approving an EV Phase 2 and that these discussions are best done in a workgroup where stakeholders can develop a consistent framework across utility programs.[975] She testified that the Commission's EV Workgroup has had insufficient opportunity to review BGE's EV Phase 2 programs.[976] She testified that the Workgroup received a brief slide deck from BGE in April 2023 and that members then submitted initial comments, but further discussion had not occurred before BGE filed its EV Phase 2 proposal with the Commission.[977] She testified that, among other things, the Workgroup should consider (1) whether market barriers at issue in Phase 1 still exist; (2) whether the market or utilities should provide some Phase 1 EV programs; (3) whether Phase 2 should be considered a pilot; (4) whether there should be changes in the filing structure, approval, and cost-recovery process; and (5) whether to create consistent definitions for Phase 2 program offerings, such as type and scope of equipment to be used.[978]

Witness Lane testified that the reconciliation process is an inadequate protection for ratepayers.[979] She testified that the Commission could, if it approves any of BGE's EV programs in Case Nos. 9696 and 9478, order BGE to include those costs in its next rate case or create a rider to track and true-up those costs on an annual basis.[980]

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[974] *Id*.
[975] *Id*. at 79.
[976] *Id*. at 78-79.
[977] *Id*. at 79.
[978] *Id*.at 79-80.
[979] *Id*. at 74.
[980] *Id*. at 75.

BGE Rebuttal

In rebuttal, BGE witness Case testified that the Commission-approved cost recovery mechanism for EV programs is base rates, and without inclusion of the proposed 2024-2026 EV programs in this case, the benefits of those programs will not be realized.[981] He testified that including the proposed programs in rates now will reduce the magnitude of reconciliation necessary, assuming the Commission approves a 2024-2026 EV program.[982] He testified that Maryland's Climate Pathway Report identified access to charging stations, affordability of EVs, and addressing range anxiety as key concerns.[983] He testified that BGE intends to continue to discuss its Phase 2 proposals with the EV Workgroup, notwithstanding its inclusion of budgets in this case.[984]

OPC Surrebuttal

In surrebuttal, OPC witness Lane testified that witness Case is ignoring that Case No. 9478 only pertained to the Phase 1 EV pilot portfolio, which had a sunset date followed by a third-party evaluation, and did not establish cost-recovery for any possible future EV pilots.[985]

She testified that there are open questions about the costs for the electric school bus pilot and the rebate limit under the CSNA, which could materially change the program budgets for which BGE is now requesting approval.[986]

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[981] Case Rebuttal at 50.
[982] *Id*. at 51.
[983] *Id*. at 52.
[984] *Id*.
[985] Lane Surrebuttal at 6.
[986] *Id*.

She testified that the proposed reconciliation mechanism does not overcome the requirement that approved costs be just and reasonable, for which insufficient information has been provided.[987]

She testified that BGE should make it explicit if it intends to withdraw its proposed EV programs if the Commission denies cost recovery in this case.[988]

She testified that there remain policy questions related to a potential Phase 2 that have yet to be addressed, including: (1) whether market barriers still exist; (2) whether some Phase 1 programs are better provided by the market; (3) whether Phase 2 should still be considered a pilot; and (4) changes to the filing structure, approval, and cost-recovery process.[989]

b. Recovery of Non-Capital Expenditures

OPC

OPC witness Lane testified that BGE is operating under the assumption that the Commission will approve an identical recovery mechanism for Phase 2 EV programs as it used for Phase 1 EV programs, that being to require utilities to seek cost recovery in a future case for EV programs approved.[990]

She testified that Phase 2 contains assets for which BGE requests regulatory asset treatment even though they will be customer investments neither owned nor maintained by BGE.[991] She recommended that BGE should not categorize non-capital expenditures (such as customer rebates and incentives for non-peak charging) as a regulatory asset, in light of

[987] *Id*. at 7.
[988] *Id*. at 8.
[989] *Id*. at 9.
[990] Lane Direct at 72, citing Order No. 88997 at 77, n. 170.
[991] Lane Direct at 83-84.

the Commission's decision to end the amortization cost-recovery approach for EmPOWER Maryland programs.[992] She testified that California recently ended utility capitalization of customer-side-of-the-meter EV infrastructure incentivized through utility EV programs because of affordability concerns.[993] She testified that the difference between regulatory asset treatment and otherwise is a 21 percent increase in costs to ratepayers over the amortization period.[994]

She recommended that BGE's EV Phase 1 cost-recovery rules not be held to apply to any other potential EV programs, such as Phase 2 or the electric school bus pilot.[995] She further recommended that cost recovery questions should be addressed in the conclusion of the Phase 1 EV pilot, not in a single utility's rate case.[996]

<u>*BGE Rebuttal*</u>

In rebuttal, BGE witness Frain testified that OPC witness Lane is over-generalizing from the Commission's decision to change the cost recovery approach for EmPOWER Maryland programs.[997] He testified that the Commission has historically placed EV program costs into a regulatory asset, which provides for the tracking of costs and a prudency review of amounts deferred.[998]

<u>*OPC Surrebuttal*</u>

In surrebuttal, OPC witness Lane testified that her recommendation regarding cost recovery was only applicable to non-capital EV program costs, in the form of customer

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992 *Id*.
993 *Id*.
994 *Id*.
995 *Id*.at 82.
996 *Id*.
997 Frain Rebuttal at 19.
998 *Id*.

rebates and incentives, which are not capital assets owned, operated, and maintained by BGE and would normally be treated as an operating expense.[999] She testified that EmPOWER offers a cautionary example of the increased burden on ratepayers from continued categorization of non-capital program expenditures as a regulatory asset.[1000] She testified that EV costs are not the sort of extraordinary, non-recurring expenses that justify regulatory asset treatment, such as COVID-19 or natural disaster incremental costs.[1001]

c. Including Costs of Public Charging Stations in Rate Base

MEA

MEA Director Pinsky testified that the Commission should not include the costs of EV public charging station programs in BGE's rate base, arguing that utility EV charging programs limit flexibility and competition within the market and unfairly spreads costs across all ratepayers.[1002] He testified that public charging stations should be paid for through other dedicated funding sources, though there may be a role for utility-owned charging in rural, underdeveloped, or overburdened areas.[1003]

BGE Rebuttal

In rebuttal, BGE witness Case testified that BGE's EV programs are intended to help encourage the competitive market and EV ownership and do not supplant third-party EV companies.[1004] He testified that there has been support from charging companies for existing utility EV programs.[1005] He testified that the EV-BCA demonstrates the value of

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[999] Lane Surrebuttal at 25.
[1000] *Id*.
[1001] *Id*.at 26-27.
[1002] Pinsky Direct at 7-8.
[1003] *Id*.
[1004] Case Rebuttal at 53.
[1005] *Id*.at 54.

BGE's EV portfolio to all customers, including non-participants who benefit from environmental and public health improvements.[1006]

Commission Decision

The Commission agrees with OPC that the parallel litigation of BGE's Phase 2 EV program and electric school bus pilot program creates undesirable risks of inconsistency and confusion. These programs are novel and require careful consideration and adequate time for analysis, which they will be more likely to receive in other dockets. This approach is consistent with the Commission's handling of BGE's Phase 1 EV program, which was approved outside of a rate case before its costs were allowed to be collected. All associated costs for Phase 2 and the electric school bus pilot program shall be removed from the calculation of rates in this case.

The Commission appreciates BGE's interest in addressing the State's efforts to provide for the electrification of school buses. Given the numerous issues involved in cost effective programs impacting the utility and ratepayers as well as local governments overseeing school transportation, the Commission will consider these issues in a dedicated proceeding.

The Commission appreciates the concerns raised by MEA regarding the role of utilities in owning public charging stations. The Commission invites MEA to raise these concerns in the Phase 2 EV proceeding.

[1006] *Id.*at 54-55.

P. Energy Storage Pilot Project Costs

BGE

BGE seeks rate recovery for costs associated with its Chesapeake Beach energy storage pilot project, which is owned and operated by a third-party.[1007] The project became operational January 20, 2023.[1008]

Staff

Staff witness Wilson recommended that the Commission approve BGE's request for recovery of the project costs associated with its Chesapeake Beach energy storage project.[1009] He testified that, despite some cost increases, the project continues to be cost effective.

Commission Decision

The Commission, in Order No. 89240, approved standard cost recovery rules for O&M costs attributable to the use of third-party owned assets under the energy storage pilot. The Commission accepts the undisputed recommendation of Staff and finds that the record supports the conclusion that the project is cost effective and should be included in the revenue requirement.

III. COST OF CAPITAL

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

[1007] BGE Exhibit OIA-15.
[1008] Maillog No. 242463.
[1009] Wilson Direct at 21.

observed, as bonds are issued subject to specific interest rates, this rate case features competing cost of debt projections based on the projected 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.

In this case, the Commission heard testimony on cost of capital from witnesses for BGE, Commission Staff, OPC, Walmart, and the Department of Defense ("DoD"), which recommended the following ROEs for gas and electric operations:

Table 7

Parties' Recommended ROEs for Electric and Gas Utilities		
Party	**ROE Range**	**ROE**
BGE	9.7%-11.1%	10.4% for electric and gas[1010]
Staff	9.04%-9.70%	9.45% for electric and gas[1011]
OPC	8.55% - 9.30%	9.10 for electric and gas%[1012]
Walmart		9.50% electric[1013] 9.65% gas
DoD	9.20% - 9.90%	9.40 for electric and gas%[1014]

[1010] McKenzie Direct at 50.
[1011] McAuliffe Direct at 11.
[1012] Woolridge Direct at 60.
[1013] Kronauer Direct at 19.
[1014] Walters Direct at 3.

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. As part of their analyses, most of the Parties attempted to create proxy groups of companies with comparable risk to BGE's gas and electric businesses.[1015] While the Parties generally did not dispute BGE's proposed capital structure of 52% equity and 48% debt across all three MYP years, certain Parties raised concerns regarding the proposed ROEs.

A. Proxy Groups and ROE

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

<u>BGE</u>

BGE witness Adrien M. McKenzie testified that he created a separate electric proxy group of 26 electric utilities that he referred to as the "Electric Group."[1016] He identified his proxy group using the following criteria: (1) included in the Electric Utility Industry groups compiled by Value Line; (2) paid common dividends over the last six months and have not announced a dividend cut since that time; (3) had no ongoing involvement in a major merger or acquisition that would distort quantitative results; (4) assigned a Value Line Safety Rank of "1" or "2;" and (5) assigned a Value Line Financial Strength Rating of B++ or higher.[1017] Witness McKenzie also stated that his analysis considered credit ratings from S&P and Moody's in evaluating relative risk. Specifically, his analysis

[1015] Walmart's direct testimony does not include discussion of the creation or use of a proxy group.
[1016] McKenzie Direct at 15.
[1017] *Id.* at 15.

excluded any companies with ratings below Baa2 and BBB assigned by Moody's and S&P respectively.[1018]

Mr. McKenzie noted that he also created a separate gas proxy group of eight gas utilities that he referred to as the "Gas Group."[1019] He identified the gas proxy group with the following criteria: (1) using companies included in the Natural Gas Utility industry group compiled by Value Line; (2) eliminating South Jersey Industries due to its pending acquisition by Infrastructure Investment Fund, and excluding UGI Corporation because it is engaged primarily in propane sales and marketing, which are not directly comparable to BGE's gas distribution operations; (3) verifying that the remaining firms have not cut dividend payments during the past six months and have not announced a dividend cut since that time; and (4) confirming that all of the proxy group firms have investment-grade credit ratings from S&P and Moody's.[1020]

Witness McKenzie also evaluated the investors risk perceptions for the Electric and Gas groups by looking at Value Line's primary risk indicator of Safety Rank, Value Line's Financial Strength Ratings, and finally beta which measures a utility's stock price volatility relative to the market as a whole and reflects the tendency of a stock's price to follow changes in the market.[1021] Based on Mr. McKenzie's analysis, a comparison of these risk indicators between his proxy electric and gas groups and BGE shows that "investors would likely conclude that the overall investment risks for the firms in the Electric and Gas Groups are generally comparable to BGE."[1022]

[1018] *Id.*
[1019] *Id.* at 16.
[1020] *Id.* at 15-16.
[1021] *Id*. at 17.
[1022] *Id*. at 18.

Mr. McKenzie used two ROE models—discounted cash flow ("DCF") and capital asset pricing ("CAPM")—as well as the risk premium method, in his analysis.[1023] He recommended an ROE of 10.4% for both BGE's electric and gas utility operations.[1024]

Staff

Staff witness McAuliffe testified that he identified an electric proxy group of 32 companies and a gas proxy group of eight companies that are identified as electric or gas utilities by Value Line that have a Value Line financial strength rating of B++ or greater.[1025] For his analysis, he required that each company have all relevant data from Value Line necessary and also used the DCF and capital asset pricing CAPM models to develop his recommended ROE, excluding parent company Exelon, as well as any utility that was involved in a merger during his sample period.[1026] Mr. McAuliffe removed from his results any company that had an ROE below seven percent or above 14 percent.[1027] He recommended an ROE of 9.45% for electric and gas utility operations, lowering BGE's current gas operations from 9.65% and raising current electric operations from 9.40%.[1028] He stated that his recommendation fell within the range of his analysis results and adhered to the Commission's precedent for applying gradualism to determinations of ROE.[1029] He stated that BGE's proposed ROE is much higher than the nationwide average for electric and gas utilities.[1030]

[1023] McKenzie Direct at 50.
[1024] *Id.* at 51.
[1025] McAuliffe Direct at 19.
[1026] *Id.*
[1027] *Id.*
[1028] *Id.* at 11.
[1029] *Id.*
[1030] *Id.* at 36.

OPC

OPC witness Woolridge adopted BGE's proposed capital structure with a common equity ratio of 52.0% while noting that it has more equity and less financial risk than his three proxy groups and BGE's parent company, Exelon.[1031] Dr. Woolridge also adopted BGE's proposed long-term debt rates and used the DCF and CAPM to develop his recommended ROE.[1032] Dr. Woolridge used three proxy groups–a proxy group of publicly held electric utility companies, witness McKenzie's proxy group, and a group of publicly held gas distribution companies.[1033] Dr. Woolridge testified that because BGE's investment risk level is below the average of the three proxy groups, he developed a risk adjustment of 15 basis points for BGE and resulted in an ROE of 9.10%.[1034]

Walmart

Walmart witness Kronauer recommended that the Commission reject BGE's proposed 10.40% ROE for both electric and gas operations and not approve an ROE higher than BGE's current 9.50% for electric and 9.65% for gas unless "BGE can sufficiently and substantially demonstrate that a higher ROE is required."[1035] He testified that the Commission should closely examine any requested ROE increases in light of the Commission's and other states' recently approved rate case ROEs, customer impact of the resulting revenue requirement increase from BGE's currently approved electric and gas ROEs, and the proposed use of an MYP, which permits BGE to include projected costs in its rates at the time they will be in effect.[1036] He testified that the difference between the

[1031] Woolridge Direct at 4.
[1032] *Id.*
[1033] *Id.* at 4-5.
[1034] *Id.* at 5.
[1035] Kronauer Direct at 4.
[1036] *Id.* at 8.

currently authorized electric ROE of 9.50% and the proposed 10.40% ROE resulted in an estimated requested revenue increase of 37.9% for 2024, 33.5% for 2025 and 29.7% for 2026.[1037] He further stated that the difference between the currently authorized gas ROE of 9.65% and the proposed 10.40% ROE resulted in an estimated requested revenue increase of 11.4% for 2024, 12.6% for 2025 and 7.5% for 2026.[1038] Mr. Kronauer noted that the Company's proposed electric and gas ROEs are counter to recent Commission decisions and are significantly higher than ROEs approved by the Commission in cases decided from 2019 to present.[1039]

DoD

DoD witness Walters testified that the trend in approved utility ROEs has declined in recent years and has more recently remained below 10.0%. He recommended an ROE of 9.40% and requested that the Commission reject BGE's proposed 10.40% as excessive.[1040]

Mr. Walters stated that he used the following models to estimate BGE's cost of common equity: (1) DCF model using consensus analysts' growth rate projections; (2) constant growth DCF using sustainable growth rate estimates; (3) multi-stage growth DCF model; (4) risk premium model; and (5) CAPM.[1041] Witness Walters relied on the same electric proxy group developed by BGE's witness McKenzie, but excluded one company, Chesapeake Utilities, that did not have a credit rating from S&P or Moody's.[1042] His proxy group had average credit ratings of BBB+ and Baa1 from S&P and Moody's,

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[1037] *Id.* at 9.
[1038] *Id.* at 10.
[1039] *Id.* at 10-13.
[1040] Waters Direct at 3.
[1041] *Id.* at 23.
[1042] *Id.* at 28-29.

respectively.[1043] He noted that his proxy group had an average common equity ratio of 40.7% (including short-term debt), as calculated by S&P Global Market Intelligence, and 45.0% (excluding short-term debt), as calculated by Value Line.[1044] He stated that BGE's requested common equity ratio of 52.00% (excluding short-term debt) significantly exceeded the proxy group's equity ratio, and the evidence suggested that BGE was significantly less risky than the proxy group.

B. Rates of Return

BGE witness Vahos testified that BGE requests overall ROR for both electric and gas operations of 7.39% for 2024, 7.45% for 2025, and 7.56% for 2026 in the MYP, based on BGE's projected embedded cost of debt for each year, as well as a 10.40% return on equity for both electric and gas, as recommended by Company witness McKenzie in his testimony.[1045]

Mr. Vahos explained that because interest rates have recently risen significantly, and BGE's requested rates are based on a cost of debt forecast for the 2024-2026 MYP period, actual interest rates for the period will likely substantially differ, even decrease, from any interest rate forecast today. He described BGE's proposal to true-up the long-term cost of debt during the reconciliation process in order to mitigate against long-term interest rate volatility and to keep customers and the Company whole.[1046] Mr. Vahos also recommended an alternative where the Commission could authorize the Company to enter into an interest rate hedging mechanism.[1047] However, he emphasized that BGE

[1043] *Id.* at 29.
[1044] *Id.*
[1045] Vahos Direct at 21.
[1046] *Id.* at 26.
[1047] *Id.*

recommended the Commission recognize the risk of fluctuating interest rates and allow the forecasted cost of debt to be reconciled within the MYP reconciliation process to allow for a true-up to the actual cost of debt.[1048]

BGE maintained that the current volatility of interest rates justifies BGE's proposal of projected long-term interest rates, along with one of the Company's proposed mitigation methods, would protect both BGE and customers against long-term interest rates differing from those used to calculate the overall rates of return in this matter.[1049]

Witness McAuliffe, using BGE's capital structure, recommended a ROR of 6.74%, and that BGE's current cost of debt as of December 31, 2022, be used in the capital structure, and that the cost of debt remain the same each year of the MYP.[1050]

Dr. Woolridge recommended a rate of return for BGE of 6.71% in 2024, 6.78% in 2025, and 6.88% in 2026.[1051]

On rebuttal, Mr. Vahos objected to Staff witness McAuliffe's recommended ROE. He stated that Staff witness McAuliffe's recommended ROE of 9.45% for electric and gas, compared to his recommendation of 9.50% in the previous BGE rate case (Case No. 9645) revealed that Mr. McAuliffe did not contemplate the rising financial costs to the same degree he considered the decrease of financial costs in Case No. 9645.[1052] He noted that the other ROE witnesses in Case No. 9645 "seem to at least recognize the upward pressure on ROE and impacts of the increased cost of capital and record inflation with increases in their ROEs [sic] recommendations in comparison to their recommendations in Case No.

[1048] *Id.* at 26-27.
[1049] BGE Initial Brief at 68.
[1050] McAuliffe Direct at 34.
[1051] Woolridge Direct at 96.
[1052] Vahos Rebuttal at 46.

9645."[1053] He provided information comparing the recommended ROEs of Staff, OPC and DoD, in Case No. 9645 and the present rate case, indicating that only Staff's ROE recommendation is lower in the present rate case than in Case No. 9645.[1054] Mr. Vahos also compared the 30-year U.S. Treasury yields and BGE's authorized ROEs at the time of this case and Case No, 9645, with Mr. McAuliffe's recommended electric and gas ROEs.[1055] He asserted that a "clear disconnect" existed between Mr. McAuliffe's recommendations and the 30-year U.S. Treasury yields.[1056]

Mr. Vahos stated that Dr. Woolridge's recommended ROEs in three of BGE's last four rate cases are consistently lower than BGE's authorized ROEs and continue to be unreasonable.[1057] With regard to Mr. Walters' recommended ROEs, Mr. Vahos stated that the recommendations aligned with averages from previous years, such as before 2021, that saw substantially lower financing costs.[1058] He similarly found that the other interveners' ROE recommendations were lower than the national industry average of 9.75% for gas and 9.70% electric distribution utilities during the three-month period ending March 31, 2023, and therefore significantly lower than a reasonable and appropriate ROE.[1059] He emphasized that the Commission should consider the increase in cost of capital, record high inflation, and alignment to recent national averages of authorized ROEs since Case No. 9645 when authorizing an ROE for the present case.[1060]

[1053] *Id.* at 45-46.
[1054] *Id.* at 46.
[1055] *Id.*
[1056] *Id.*
[1057] *Id.* at 47.
[1058] *Id.* at 48.
[1059] *Id.* at 48-49.
[1060] *Id.* at 50.

Mr. Vahos was similarly concerned regarding Mr. McAuliffe's recommendation of a fixed cost of debt for the MYP period without consideration of fluctuating interest rates, as opposed to BGE's inclusion of projected long-term rates in its estimate.[1061]

Witness McKenzie on rebuttal agreed with Mr. Vahos that Staff, OPC and DoD witness' recommended ROEs are too low and counter to the standards for a fair and reasonable ROE for BGE's electric and gas operations, based on current interest rates and authorized ROEs for other utilities, and the Commission must grant BGE the opportunity to earn a competitive return that reflects a significant increase in long-term capital costs.[1062] Mr. McKenzie testified that the expected earned RORs for the companies in the other witnesses' proxy groups suggested a 10.9% to 11% ROE.[1063] He analyzed what he described as flaws in the other Parties' analysis methodologies, including the use of CAPM, and opined that other witnesses' appraisals of current capital market conditions were incomplete and possibly misleading.[1064]

Witness McKenzie noted that key interest rate indicators, as cited by the other witnesses, reveal that required return on debt securities have increased by 276 basis points between August 2020, during BGE's Case No. 9645, and the current case.[1065] He noted further that the Federal Reserve's target range midpoint for federal funds increased by 525 basis points, and the anticipated long-term inflation rate increased by 52 basis points.[1066] He compared these numbers to the other witnesses' ROE recommendations, which

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[1061] *Id.* at 51.
[1062] McKenzie Rebuttal at 2 and 4.
[1063] *Id*. at 3.
[1064] *Id.*
[1065] *Id.* at 7.
[1066] *Id.*

indicated an average increase of 15 basis points during the above-referenced time period.[1067]

Witness McKenzie also disputed the claims of witnesses McAuliffe and Woolridge that investors expect interest rates and yields to decrease, stating that long-term consensus projections of top economists that pointed to predictions of consistently elevated bond yields through 2028.[1068] Mr. Kenzie also disagreed with witness McAuliffe's testimony that a recession would lead to lower ROE's.[1069]

On surrebuttal, Dr. Woolridge maintained that he noted increased interest rates in his testimony, and stated that since interest rates declined much further than authorized ROEs in 2020-2021, authorized ROEs need not increase to the same degree that interest rates have increased in 2022-2023.[1070] According to Dr. Wooldridge, Mr. McKenzie inaccurately claimed that OPC's ROE recommendation is too low after comparing it to authorized electric and gas utility ROEs and the results of Mr. McKenzie's expected earnings approach.[1071] Dr. Woolridge objected to this approach, stating that it does not measure cost of equity capital and ignores capital markets.[1072] Dr. Woolridge argued that Mr. McKenzie provided no evidence that his 9.1% ROE recommendation failed to meet the standards that it should be comparable to returns investors expect to earn on other investments of similar risk, sufficient to assure confidence in the utility's financial integrity, and adequate to maintain and support the utility's credit and attract capital.[1073]

[1067] *Id.* at 9.
[1068] *Id.* at 11.
[1069] *Id.* at 12.
[1070] Woolridge Surrebuttal at 3.
[1071] *Id.* at 29.
[1072] *Id.* at 27-28.
[1073] *Id*. at 29-30.

He noted that his recommendation was based on BGE's consistent financial performance, growing revenues and an average ROE of 9.21% in the past five years.[1074]

Staff witness McAuliffe, on surrebuttal, dismissed as simplistic Mr. McKenzie's statements regarding the need to match the degree of interest rate increase to the ROE increase.[1075] He questioned BGE witness McKenzie's disagreement with his assessment that the MYP would reduce regulatory lag and reduce risk to BGE, noting that BGE was not required to file an MYP and could have chosen to resume filing rate cases based on a historical test year.[1076] Witness McAuliffe stressed that he abided by the Commission's preference for the use of gradualism in proposing an ROE, although it was less of a concern than in the previous BGE rate case because his analysis resulted in ROE recommendations similar to BGE's current authorized ROEs. [1077]

He defended his recommendation for a reduction in ROE in return for a true-up of BGE's cost of debt, stating that the true-up would guarantee BGE's recovery of nearly half of its capital structure, and the guarantee would be favorably viewed by investors as a lowered risk.[1078] Therefore, he stated, if the risk in investing in BGE is reduced, a corresponding ROE reduction is needed because investors would require less of a return.[1079]

Witness McAuliffe disagreed with Witness McKenzie's testimony that an underperforming utility should receive a higher allowed ROE in order to compete for

[1074] *Id*. at 30.
[1075] McAuliffe Surrebuttal at 4.
[1076] *Id.* at 11.
[1077] *Id.* at 12.
[1078] *Id.*
[1079] *Id.*

capital, stating that a utility controls its ability to earn its return.[1080] Mr. McAuliffe added that such an increase in an allowed ROE would undermine the Commission's goal of balancing utility and ratepayer interests by allowing utilities to continue over-investing in rate base, lowering earned returns and causing the Commission to allow the utilities to have higher ROEs.[1081]

Witness McAuliffe continued to reject witness Vahos' recommendation of a projected cost of debt, arguing it was "highly subjective and provides little to no benefit to BGE or its ratepayers."[1082]

C. Cost of Debt

BGE witness Vahos described BGE's proposed embedded cost of debt for each of the 2024-2026 MYP years, which he explained was representative of the overall cost for all long-term debt projected to be outstanding at the end of each MYP year, including any new long-term debt issuances and retirements planned for each period.[1083] Mr. Vahos stated that the projections interest rate assumptions applied to the debt issuance balances are based on the 2022 year-end 30-year Treasury forward curve, plus an adder of 143 basis points based on indicative pricing for comparable utilities at the time the budget was finalized in January 2023.[1084] He noted that in BGE's previous MYP Case No. 9645, the Commission approved a rate of return that included fixed cost of debt for the MYP period, with no consideration for interest rate fluctuations.[1085] Mr. Vahos stated that because of fluctuating interest rates, the actual cost of debt led to an over-recovery of interest expense

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[1080] *Id*. at 24.
[1081] *Id.* at 24-25.
[1082] *Id.* at 27.
[1083] Vahos Direct at 24.
[1084] *Id.*
[1085] *Id.*

in 2021 and an under recovery of interest expense in 2022, while BGE is also projecting an under-recovery in 2023.[1086]

He stated that BGE also proposes to include in the reconciliation process a true-up for the actual cost of long-term debt starting in MYP 2 and going forward, in order to recover the actual cost of debt, while ensuring customers can recover any costs resulting from a lower actual cost of debt.[1087]

Mr. Vahos described an alternative proposal to the true-up, where BGE would enter into a "forward starting interest rate hedging mechanism," lock in a specific interest rate for up to 70% of the principal of an issuance.[1088] He explained that if the interest rate at the time of issuance was higher than the agreed upon rate in the hedging mechanism, BGE would receive proceeds that represented the rate differences, and if the interest rate at the time of issuance was lower than the agreed upon rate in the hedging mechanism, BGE would pay the difference.[1089] BGE proposed to include any hedging mechanism impacts associated with the interest rate hedging agreement in future MYP reconciliations.[1090]

Staff witness McAuliffe objected to BGE's proposal to include a cost of debt true-up for BGE's last MYP, which BGE witness Vahos described as necessary in light of recent interest rate increases.[1091] Mr. McAuliffe stressed that despite recent interest rate increases, there are predictions that rates will begin to decrease in the next year and rate predictions over the next three years will be inaccurate. Therefore, he stated, allowing the cost of debt true-up would reduce or eliminate the incentive for BGE to prudently obtain debt at the

[1086] *Id.* at 25.
[1087] *Id.* at 26.
[1088] *Id.* at 27.
[1089] *Id.* at 28.
[1090] *Id.*
[1091] Testimony of Staff witness McAuliffe at 21.

most advantageous rate, because the Company would be made whole regardless of the cost of debt.[1092] He noted that the Commission previously rejected a cost of debt true-up in BGE's previous MYP Case No. 9645.[1093]

Mr. McAuliffe recommended that if the Commission approves BGE's proposal to true-up its cost of debt, the Commission should also assess a minimum five-basis point reduction to BGE's awarded ROE to account for the decrease in risk.[1094]

Mr. McAuliffe also objected to Mr. Vahos' proposal that, as an alternative to the true-up proposal, BGE would begin an interest rate hedging mechanism, where BGE would hedge 70% of the principal of the issuance, and requiring BGE to receive proceeds or pay proceeds based on what the agreed interest rate was and what rates were at the time of issuance.[1095] He added that BGE's proposal would extend to any hedging mechanism impacts in future MYP reconciliations, similar to BGE's proposed true-up.[1096] He recommended that the Commission also reject the hedging proposals.[1097]

Mr. McAuliffe further objected to and recommended rejection of witness Vahos' proposal to use three different projected cost of debt levels for each year of BGE's MYP – a similar proposal to that made in Case No. 9645, which the Commission rejected in favor of a fixed cost of debt rate to be applied to BGE's capital structure over the course of the MYP.[1098]

[1092] *Id*. at 22.
[1093] *Id.*
[1094] *Id.* at 21-22.
[1095] *Id*. at 22.
[1096] *Id.* at 23.
[1097] *Id.*
[1098] *Id*.

Witness Vahos disputed Staff witness McAuliffe's recommended fixed cost of debt for the 2024-2026 MYP years, based on the Company's cost of debt as of December 2022, with no recognition of interest rate fluctuations.[1099] Mr. Vahos countered that BGE's use of projected long-term debt interest rates in its forecasted cost of debt (based on the 2022 30-year Treasury curve, with an adder based on indicative pricing for similarly rated utilities) provides the best cost of debt estimate for the MYP period, since BGE is limited by current market conditions and interest rates.[1100] He expressed concerns regarding a lack of ability to true-up the actual cost of debt in the previous MYP Case No. 9645.[1101] Mr. Vahos stated that that exclusion leaves BGE and customers at the mercy of any volatility of interest rates, leading to over or under recoveries of actual interest costs.[1102] He explained that the cost of debt has a direct input to the rate of return, and the lack of a true-up could lead to a lack of recovery and amount to a permanent disallowance.[1103] He emphasized BGE's proposal to include cost of debt in future reconciliations would provide a fair and balanced opportunity for the Company to recover its actual cost of long-term debt and help ensure that customers are made whole.[1104] Mr. Vahos recommended that the Commission approve the use of BGE's projected cost of debt over the MYP period, and authorize the inclusion of the cost of debt in future MYP reconciliations.

[1099] Vahos Rebuttal at 51.
[1100] *Id.*
[1101] *Id*. at 52.
[1102] *Id.*
[1103] *Id.* at 53.
[1104] *Id.* at 24.

Commission Decision

A public utility must charge just and reasonable rates for the regulated services that it provides.[1105] Pursuant to well-established regulatory principles, regulated utilities are allowed the opportunity to recover the costs of prudently incurred debt financing. Court precedent, primarily *Bluefield*[1106] and *Hope Natural Gas*,[1107] 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.[1108]

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.

The Commission finds that ROEs of 9.5% for BGE's electric distribution service and 9.45% 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 BGE's financial

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[1105] 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.
[1106] *Bluefield Water Works and Improvement Co. v. Pub. Serv. Comm'n of W. Va.,* 262 U.S. 679 (1923).
[1107] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).
[1108] PUA § 3-112.

integrity, and are adequate to maintain and support BGE's credit and attract any needed capital.

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 at the center range recommended by Staff.[1109] They fall below the high end of DOD's recommended range, except for BGE.[1110] They fall above the range of reasonableness recommended by OPC, again except for BGE.[1111] And they fall toward the middle of the bottom half of the range recommended by BGE.[1112]

The Commission further finds that the ROEs approved in this Order for both gas and electric are within the range of solutions proposed by Staff and are justifiable based on the *Bluefield* and *Hope* decisions, including principles of comparable risk (i.e. being commensurate with returns on investments in other enterprises with corresponding risks), financial integrity, attracting needed capital, and considering the impact of current market conditions.

The Commission, in light of recent laws and policies that are ushering in a reduction in the use of gas and an increase of electrification, prefers a higher ROE for electric distribution as a reflection of the policy shift. The slightly lower gas ROE should incentivize BGE, a dual fuel utility, to invest in its electric distribution system rather than gas distribution.

[1109] Mr. McAuliffe recommended an ROE for BGE's gas business of 9.45% and for BGE's electric business of 9.45%. McAuliffe Direct at 11.
[1110] Mr. Walters found a range of reasonableness for BGE's combined gas and electric businesses of 9.20% - 9.90%. Walters Direct at 3.
[1111] Dr. Woolridge found a recommended range of reasonableness of between 8.55% - 9.30%. Woolridge Direct at 60.
[1112] Mr. McKenzie found a range from 9.7%-11.1%. McKenzie Direct at 50.

Despite the current market conditions comprising higher interest rates and inflation, the above-referenced authorized ROEs are just and reasonable and will provide BGE with sufficient access to capital. The Commission also recognizes OPC's argument that the rate that is set does not have to absolutely reflect the interest rates in the economy as a whole.

The Commission's approval of BGE's request for an MYP, including a reconciliation, provides an overall lower risk for the utility and an opportunity to revisit the ROE should economic conditions deteriorate. The Commission finds that attempts to project interest rate variations over the three-year MYP are too speculative and declines to use them here. The MYP which BGE initially requested and the continuation that BGE is requesting in this proceeding provides faster cost recovery which consequently lowers the Company's risk profile.

The Commission approves BGE's proposed capital structure except for the proposed cost of debt. 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.[1113] BGE's proposed capital structure, except for the cost of debt, was not challenged by other Parties and is in line with BGE's actual capital structure and with those historically approved by this Commission.

The Commission denies BGE's proposed cost of debt and any associated true-up mechanisms and accepts Staff's proposal. Staff witness McAuliffe is correct that the Commission in the previous BGE MYP order expressed preference for the use of a single,

[1113] Case No. 9484, *Application of Baltimore Gas & Electric*, Order No. 88975 at 70-71.

fixed cost of debt rate over the course of the MYP.[1114] Additionally, the Commission agrees with Staff witness McAuliffe that it is difficult to project interest rates.[1115] The Commission also reaffirms its previous finding to not include a cost of debt true-up within a MYP to ensure BGE continues to have the appropriate incentives to obtain debt capital at the most favorable rates.[1116]

IV. Cost of Service

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 rates for the numerous customer classes.

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.

BGE witness Manuel explained that there are generally three basic steps to measure customer class responsibility for rate base and expense: (1) functionalization; (2) classification; and (3) allocation.[1117]

Functionalization is the process of dividing rate base and expense components of the cost of service study into specified utility functions based on the characteristics of those

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[1114] Order No. 89678, Case No. 9645 at 155.
[1115] McAuliffe Direct Testimony at 24.
[1116] Order No. 89678, Case No. 9645 at 155.
[1117] Manuel Direct at 5-6.

components. BGE functionalizes its gas delivery service assets and related expenses as either production, storage or distribution operations. All of these costs, however, are recovered through base distribution charges. Gas commodity costs, on the other hand, are recovered through BGE's Rider 2 – Gas Commodity Price – and are not included in the GCOSS.

Classification is the process of separating the functionalized rate base and expenses into categories that relate to how costs are caused. Distribution costs are primarily classified between demand and customer-related components. Demand- related costs are generally driven by customer class Non-Coincident Peak ("NCP") demand and/or coincident peak ("CP") demand levels, while customer-related costs are driven by the number and cost of customers connecting to gas mains and the necessary requirements for the utility to service those customers (i.e., metering, meter reading, account processing, and billing systems). There are some instances in which distribution costs (though minor in relative cost significance) are variable with customer class consumption; in those instances, expenses would be classified as energy-related.

Allocation is the process through which rate base and expenses in each of the classified cost categories are assigned to customer classes according to customer load impositions on the distribution system and/or customer connection requirements. 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 (i.e., meters). When the costs are not directly assignable to customer classes (i.e., mains), they are then allocated to the correct customer classes using an appropriate methodology that best represents cost causation principles. That methodology varies depending on the nature of the item being allocated and the data available at the time of the analysis.

The only disagreement raised by the parties to BGE's COSS's was by Staff. This disagreement concerned the creation of a new allocator used for various FERC accounts, whose use is proposed for BGE's next rate case.

Staff

Staff witness Delgado testified that using a lone labor or plant allocator presents potential inconsistencies for FERC accounts 303, 389, 398.[1118] For example, FERC account 303, whose costs are currently estimated at 56.06 percent labor-related, is presently allocated using a LABOR allocator but previously was allocated using a plant allocator under a prior cost allocation estimate.[1119] Witness Delgado testified that he requested, but BGE did not perform, an analysis of how much recent growth in account 303 (approximately 43 percent) is driven by labor vs plant-related costs.[1120] This creates significant variability in cost allocation.[1121]

Mr. Delgado testified that BGE has communicated that they will not conduct an updated itemized analysis for FERC accounts 303, 389, and 398.[1122] He recommended, as an alternative, using an internalized allocator that is based on both a plant and labor allocator for the FERC accounts that have a ratio of plant to labor or labor to plant that is between 40 and 60 percent.[1123] He called this proposed allocator "PLANTLAB" and proposed basing it 50 percent on the PTDPLT (plant) allocator and 50 percent on the

[1118] Delgado Direct at 12.
[1119] *Id.*
[1120] *Id.*
[1121] *Id.*
[1122] *Id.* at 13.
[1123] *Id.*

LABOR (labor) allocator.[1124] Mr. Delgado testified that the Commission took a similar approach in Case No. 9490, Order No. 89072.[1125]

Mr. Delgado recommended that the Commission direct BGE to provide an updated itemized analysis for accounts 303, 389, and 398 in its next rate case if costs for those accounts increase by more than 25 percent from this proceeding, with allocators adjusted accordingly.[1126]

BGE Rebuttal

In rebuttal, BGE witness O'Neill testified that BGE believes the use of the proposed PLANTLAB allocator is reasonable but that it disagrees with Staff's methodology in developing the allocator.[1127] She testified that the PLANTLAB allocator should have used the allocation factors, not the ratios, of the PTDPLT and LABOR allocators.[1128]

BGE witness O'Neill testified that BGE already performed an itemized analysis of these FERC accounts for the current rate case, and that the result of that analysis yields an extremely immaterial impact on the overall class RROR. Witness O'Neill further testified that such analyses involve a significant amount of time and effort to complete.[1129]

Staff Surrebuttal

In surrebuttal, Mr. Delgado testified that he deliberately chose not to utilize the methodology proposed by BGE witness O'Neill because BGE's method did not account for the fact that the PTDPLT account balance was significantly larger than the LABOR account balance, resulting in a blended allocator that would be heavily weighted by the

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[1124] *Id.*at 13-14.
[1125] *Id.* at 14.
[1126] *Id.*at 15.
[1127] O'Neill Rebuttal at 3.
[1128] *Id.*at 3-4.
[1129] *Id.*at 5.

plant account balance, whereas the itemized analysis shows the primary cost driver for FERC accounts 303, 389, and 398 to be labor.[1130] He further testified that BGE's proposal results in an allocator that is largely indistinguishable from the PLANT allocator and that would not be appropriate for allocating costs whose main cost driver is labor.[1131]

Mr. Delgado testified that an itemized analysis is necessary in order to track whether the cost drivers of those accounts are continuing to vary, thus necessitating a different allocator be used.[1132] He testified that he originally recommended only conducting this analysis for accounts 303, 389, and 398 and only if the costs for these accounts increase by more than 25 percent, but (in response to concerns about unnecessary work) changed his recommendation to require an itemized analysis for account 303 only, and only if the total balance for that account changes by more than 50 percent from this proceeding.[1133] He testified that account 303 is much larger than the others and has shown significant increases in BGE's last three rate cases.[1134]

Commission Decision

The Commission finds that the PLANTLAB allocator, as proposed by Staff, is a reasonable solution to the cost causation concern at issue. The Commission further finds that Staff's proposed methodology in developing the PLANTLAB allocator is more likely to result in an allocator that fits cost causation, given the concerns raised by Staff regarding the relative weights within the account balances. The Commission directs BGE to utilize

[1130] Delgado Surrebuttal at 4-5.
[1131] *Id.*at 5.
[1132] *Id*. at 7.
[1133] *Id*. at 8.
[1134] *Id*. at 8-9.

the PLANTLAB allocator, as proposed by Staff, for accounts 303, 389, and 398 in the current rate case.

The Commission also finds Staff witness Delgado's revised recommendation to conduct an itemized analysis of account 303 in the event that the total balance of the account changes by more than 50 percent from this proceeding is reasonable, given the concerns about shifting cost allocation for that account. BGE is directed to include that analysis in its next rate case, if that threshold is met.

The Commission otherwise accepts as undisputed the use of BGE's gas and electric COSS's as a guide for setting rates in this case.

V. Staff's Proposal to Shift Revenue Between Years

Staff

Staff witness Thomas testified that there is a ratemaking problem with both BGE and Staff's proposed revenue increases because they both include large increases in rate year 1 compared to rate years 2 and 3, with rate year 1 containing more than half of the total revenue increase.[1135] He testified that if this large rate year 1 revenue increase were moved into rate year 1 rates, it would not follow the principles of gradualism or of setting predictable rates.[1136] Mr. Thomas recommended that the Commission shift a portion of the rate year 1 revenue increase to rate years 2 and 3, with the goal of achieving an equal increase in each of the three rate years.[1137] Mr. Thomas testified that taking such a step has not previously been done in an MYP by this Commission.[1138]

[1135] Thomas Direct at 15.
[1136] *Id*. at 16.
[1137] *Id*.at 16; Table 8 at 17.
[1138] *Id*. at 17.

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that the shifting of revenue requirement between recovery years is outside the scope and expertise of a rate design witness.[1139] She testified that Staff's proposal to shift revenue from year 1 to later years does not include carrying costs.[1140] She testified that any deferral amount would need to be recovered through an adjustment rider in a short time period, which would reduce the intended rate smoothing.[1141]

Staff Surrebuttal

In surrebuttal, Mr. Thomas testified that his recommendation is supported by Commission Order No. 89226,[1142] finding that a benefit of MYPs included more predictable rates for customers by spreading changes in rates over multiple years.[1143] He testified that BGE's proposed revenue allocation front-loads rate increases into rate year 1.[1144] He testified that adjustments in the yearly revenue requirement could be done that would not require additional revenue reconciliation.[1145]

Commission Decision

The Commission appreciates the creative approach to protecting ratepayers exhibited by Staff's proposal. However, the Commission finds that there are open questions about carrying costs, mechanics, and fairness that weigh against implementation of Staff's proposal. The Commission therefore rejects this proposal.

[1139] Fiery Rebuttal at 19-20.
[1140] *Id.*at 20.
[1141] *Id.*at 20-21.
[1142] Thomas Surrebuttal at 54.
[1143] *Id*. at 3.
[1144] *Id*. at 4.
[1145] *Id*. at 5.

VI. Rate Design

A. Electric Inter-class Cost Allocation

The allocation of costs among electric classes in this case contains three interrelated issues: the selection of a cost allocation method, the concern that Schedule T is over-collecting, and the amount of future tax benefits, if any, to accelerate into this rate case. The last issue was discussed above and will not be repeated here except in the decision section.

This section of the Order will address the party positions on those issues in order and conclude with a single decision that addresses all the issues together.

1. Cost Allocation Method

BGE

BGE witness Fiery proposed a two-step revenue allocation method.[1146] Her first step assigned revenue to Schedule R (which is the only class whose Relative Rate of Return ("RROR") is below 0.90) until its RROR was half-way to 0.90. Her second step assigned revenue to the existing rate classes in proportion to base distribution revenues, after step one, but with no additional revenue assigned to Schedule PL, EVP, or T.[1147]

Staff

Staff witness Hoppock recommended that the Commission use a four-step revenue allocation method for allocating revenue among the electric classes.[1148] He testified that his method is preferable to BGE witness Fiery's two-step method because his approach keeps Schedule SL within an RROR of 0.9 to 1.1.[1149]

[1146] Fiery Direct at 18-19.
[1147] *Id*. at 19.
[1148] Hoppock Direct at 2 and 68.
[1149] *Id*. at 69.

Mr. Hoppock testified that in his first step he excluded highly over-earning classes with an ROR of more than 2.0 (only Schedule PL and Schedule T).[1150] In his second step, he allocated classes with an RROR between 0.9 and 1.1 the system percentage increase in revenue relative to BGE's 2024 forecast class distribution baseline revenue.[1151] In his third step, he allocated under-earning classes (only Schedule R) a multiplying factor of the system percentage increase in distribution revenue.[1152] In his fourth step, he allocated the remaining revenue to the over-earning classes based on BGE's 2024 forecast class baseline distribution revenue.[1153] He testified that his goal was to move the forecasted RROR of Schedule R from 0.65 to 0.78, halfway to an RROR of 0.9.[1154] Other goals were to keep classes with an RROR of 0.9 to 1.1 within that range and decrease the RROR of over-earning classes.

Walmart

Walmart witness Kronauer testified in support of BGE's proposed electric and gas cost of service allocations but recommended that, should the Commission approve a revenue requirement lower than that requested by BGE, any reduction in revenue requirement should be allocated in a manner that moves customer classes toward their respective costs of service.[1155]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that Staff's proposed four-step allocation is overly elaborate and unnecessary because it achieves the same results as BGE's proposed

[1150] *Id.*
[1151] *Id.*
[1152] *Id.*
[1153] *Id.*
[1154] *Id.*
[1155] Kronauer Direct at 24-26.

two-step revenue allocation.[1156] She testified that step three of Staff's proposed allocation, which includes a multiplying factor of the system percentage increase in distribution revenue of 1.10 times the system average increase to Schedule R, is not grounded in any factual or constructive context and is too dependent upon the overall revenue increase authorized in this case.[1157] She testified that this third step will not function as intended if the Commission changes the revenue requirement from that proposed by Staff.[1158] She recommended the Commission adopt BGE's approach of using a set dollar amount to allocate revenue requirement to under-earning classes because it will not fluctuate based on the results of the overall award in this case.[1159] Witness Fiery also testified that if there is a reduction in BGE's proposed revenue requirement, the second step should still allocate the remaining deficiency to all classes based on each class's proportion of revenue after step one.[1160]

Staff Surrebuttal

In surrebuttal, Mr. Hoppock testified that four-step allocation methods were proposed by the Potomac Electric Power Company ("PEPCO") in its current rate case and approved in a prior PEPCO case settlement, No. 9472, and the most recent Delmarva Power & Light rate case settlement, No. 9861.[1161] He testified that the use of the 1.1 multiplier is purely instrumental to his goal of bringing the Schedule R RROR from 0 .65 to 0.78 and that the 1.1 multiplier is adjustable to whatever is necessary to achieve the desired

[1156] Fiery Rebuttal at 3-4.
[1157] *Id.* at 4-5.
[1158] *Id.* at 5.
[1159] *Id.*
[1160] *Id.* at 5-6.
[1161] Hoppock Surrebuttal at 3.

RROR.[1162] He testified that BGE's preferred two-step rate causes the Schedule SL estimated RROR to fall below 0.9, which is below Mr. Hoppock's desired RROR band.[1163]

2. Schedule T

BGE

In its application, BGE proposed that the Commission apply a $200,000 reduction in revenue to Schedule T, spread over three years, on the ground that Schedule T is projected to be over-earning relative to its costs.

Amtrak

Amtrak witness Faryniarz testified that BGE's Schedule T significantly over collects compared to its cost of service.[1164] He testified that, according to BGE's ECOSS, Schedule T contributes over 19 times the BGE systemwide average rate of return, up from almost 12 times the systemwide average rate of return in its last rate case.[1165] He recommended that the Commission approve a reduction in Schedule T rates that would bring Schedule T's RROR to no more than 1.1 by the third year of this rate case.[1166]

Mr. Faryniarz testified that BGE and the Commission have, in recent rate cases, elevated gradualism well above and to the exclusion of other ratemaking principles such as cost causation, inter-class equity, and economic efficiency.[1167] He testified that this has resulted in either leaving over-contributing class' rates alone or providing only a minimum amount of relief, effectively freezing in a chronic under-recovery of the cost to serve residential customers and a chronic over-recovery of the cost to serve Schedule T

[1162] *Id.*
[1163] *Id.* at 3-4.
[1164] Faryniarz Direct at 7.
[1165] *Id*. at 8.
[1166] *Id.* at 25.
[1167] *Id.* at 13-14.

customers.[1168] Mr. Faryniarz included with his testimony a table showing the RROR for each schedule in this and the last four BGE electric rate cases, which he testified showed a worsening trend of over-collection from Schedule T.[1169] Mr. Faryniarz testified that this punishes high load factor customers like Amtrak, reducing their incentive to consume even at times when there is excess BGE plant in service and increasing fares for travelers on Amtrak and MARC trains, usage of which furthers Maryland's push to electrify transportation.[1170]

Mr. Faryniarz testified that BGE is inappropriately allocating the costs of automatic metering infrastructure ("AMI") to Schedule T customers even though those customers do not have AMI technology installed.[1171] He testified that, alternatively, BGE should promptly install AMI metering and related equipment that Schedule T customers are paying for and should also ensure those customers have immediate access to the data, summaries, and other analyses BGE does or should perform with AMI data, including real-time access to meter data and other load profiling capability.[1172]

Staff

Staff witness Hoppock supported BGE witness Fiery's proposal for the Commission to reduce Schedule T revenue by $200,000, but he recommends that the entire amount be applied to rate year 1.[1173] He testified that this change is consistent with Order

[1168] *Id.* at 15.
[1169] *Id.* at 17-19.
[1170] *Id.* at 23-24.
[1171] *Id.* at 9.
[1172] *Id.*
[1173] Hoppock Direct at 69.

No. 89678, which reduced Schedule T revenue $200,000 in rate year 1 of BGE's prior MYP.[1174]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that she does not oppose Mr. Hoppock's recommendation that Schedule T receive the full $200,000 revenue reduction in RY1 instead of spreading the reduction over the three rate years.[1175] Witness Fiery testified that BGE does not oppose a larger reduction in revenue from Schedule T, which has historically been significantly over-earning.[1176]

BGE witness O'Neill testified that all customer classes benefit from AMI through energy and peak demand reducing programs that incentivize customers to reduce usage of electricity in response to very high demand and pricing. This helps to reduce the price of energy and capacity needed to be purchased by BGE and retail suppliers, which benefits all customers.[1177] She testified that Schedule T's current allocation of AMI costs is consistent with the methodology approved by the Commission in Order No. 87884, which accepted this reasoning.[1178]

Amtrak Rebuttal

In rebuttal, Amtrak witness Faryniarz testified that Staff's $200,000 reduction in Schedule T's revenue allocation is insufficient to address the high RROR faced by Schedule T, resulting in a $2.7 million overcontribution by Schedule T.[1179] He testified

[1174] *Id.*, citing Order No. 89678 at 217, Table 4, Case no. 9645.
[1175] Fiery Rebuttal at 3.
[1176] *Id.* at 8.
[1177] O'Neill Rebuttal at 7.
[1178] *Id.*, citing Case No. 9418, *In the Matter of the Application of Potomac Electric Power Company for Adjustments to Its Retail Rates for The Distribution of Electric Energy*, Order No. 87884 (Nov. 15, 2016).
[1179] Faryniarz Rebuttal at 4-5.

that, although the Commission has generally not granted rate decreases to any class when revenue requirements are increasing, it has made exceptions for over-contributing classes where such relief would have negligible impact on other customers.[1180] He testified that the principle of gradualism should not be used to justify refusing to give rate relief because falling rates will not result in rate shock.[1181] He testified that Staff has used a different method for calculating RROR than BGE for Schedule T, making comparisons difficult.[1182]

Staff Rebuttal

In Rebuttal, Staff witness Delgado testified that Schedule T's RROR has increased from BGE's last rate case because decreased rate base allocation–due in part to decreased AMI costs allocated to Schedule T–has outpaced decreased operating income.[1183]

Staff witness Delgado also recommended that the Commission maintain the existing allocation of AMI costs because AMI investments provide system-wide benefits to all ratepayers regardless of whether they individually receive distribution through an AMI meter.[1184] He testified that this approach was first approved in Case No. 9418, where Staff's position was that AMI enabled conservation and load management practices and programs that benefit ratepayers as a whole by lowering costs.[1185] He testified that BGE agreed as part of a settlement in Case No. 9610 to allocate AMI consistent with that methodology in its last rate case, No. 9645, which it did and which the Commission approved in Order No. 89678.[1186] Also in that order, the Commission directed BGE to

[1180] *Id.* at 6, citing Case Nos. 9645 and 9326.
[1181] *Id.*
[1182] *Id.* at 11-13.
[1183] Delgado Rebuttal at 8.
[1184] *Id.* at 2 and 4.
[1185] *Id.* at 4.
[1186] *Id.* at 5.

provide an updated AMI benefit analysis in its next rate case, the present one, which it did.[1187] Mr. Delgado testified that BGE's current AMI allocation does not allocate any meter costs to Schedule T (because Schedule T customers do not have AMI meters) but does allocate costs based on a proxy for the energy saving benefits of AMI meters.[1188] Mr. Delgado testified that the reason Schedule T's RROR has increased from BGE's last rate case because decreased rate base allocation–due in part to decreased AMI costs allocated to Schedule T–has outpaced decreased operating income.[1189]

BGE Surrebuttal

In surrebuttal, BGE witness Fiery agreed with Amtrak that Staff's RROR analysis was calculated differently than BGE's RROR analysis for all electric rate classes, making comparison difficult.[1190]

Amtrak Surrebuttal

In surrebuttal, Amtrak witness Munger testified that the "used and useful" standard requires that customers not benefiting directly from AMI installations at their premises should not be allocated AMI costs, and if AMI would be useful for those customers, they should have AMI meters installed at their facilities.[1191]

Staff Surrebuttal

In surrebuttal, Staff witness Hoppock testified that Amtrak's claimed overcontribution is larger than BGE's forecasted base distribution revenue for Schedule T in 2024.[1192] He testified that gradualism for under-earning classes would absorb any

[1187] *Id.*
[1188] *Id.* at 5-6.
[1189] *Id.* at 8.
[1190] Fiery Surrebuttal at 4.
[1191] Munger Surrebuttal at 7-8.
[1192] Hoppock Surrebuttal at 17.

revenue reduction - most notably Schedule R, for which BGE proposes an 11.25 percent increase in distribution rates (after Rider 16 and rate year 1 offsets are considered).[1193]

Commission Decision

The two proposed methodologies, by BGE and Staff, take a different approach in attempting to bring the classes toward parity. The Commission is concerned, however, by the elaborate approach taken by Staff, which may prove difficult to rely on as a principled methodology in future rate cases. The Commission notes also that BGE proposed a similar banded approach here to the one it proposed in its last rate case, Case No. 9645. In that case, the Commission ultimately elected to utilize a two-step unbanded allocation approach, which has been the Commission's historic approach. That approach applied 20 percent of the total increased revenue requirement in step one to the classes with a UROR under 1.0 after adjusting net operating income for the incremental revenue increase. In step two, the remainder of the revenue requirement increase was applied to classes (except PL and T, which are significantly over-earning, and EVP which is market-based) in proportion to their current revenue as a percentage of total current revenue.

The Commission finds that the parties have not presented compelling evidence to depart from the Commission's historic two-step approach, and the two-step approach shall therefore be utilized in this current case.

Regarding Schedule T, the Commission notes the concerns of Amtrak that Schedule T's RROR has continued to worsen despite flat rates. That concern was also well-argued in Case No. 9645, where the Commission found Schedule T to be over-earning and approved a $200,000 reduction from Schedule T revenues as a part of Step-One of the

[1193] *Id.* at 18.

revenue allocation methodology. The Commission now directs BGE to remove $600,000 from Schedule T revenues as part of Step-One in the revenue allocation methodology. The Commission notes that Schedule T's cost of service has continued to fall as a result of changing cost allocations. Although Amtrak has argued that Schedule T should not bear any costs for AMI metering because it does not utilize smart meters, Schedule T's share of AMI costs is limited to those derived from estimated system-wide benefits, which benefit all customers. Amtrak's proposal to provide AMI meters to Schedule T customers would increase costs allocated to Amtrak. The Commission does not understand that to be Amtrak's goal.

Lastly, as noted above, the Commission finds that the current economic environment justifies the continued use of accelerated tax benefits in this MYP for the 2024 rate year in order to cushion ratepayers from rate shock at a time of economic vulnerability. The available tax offsets total approximately $114 million for electricity and are derived from an overcollection caused by the Tax Cuts and Jobs Act of 2017. The Commission directs that $75,687,000 in tax offsets shall be applied against the electric revenue requirement for the 2024 rate year, calculated in the same manner as in Case No. 9645.

The Commission will set rates for the MYP period for the next three years based on the following revenue requirements by year.

Table 8 - Electric Relative Rate of Return by Class

Resulting Relative Rate of Return (RROR)			
Class	**Current RROR**	**Proposed RROR**	**Allocated Amount over Course of MYP**
R	0.65	0.80	$ 134,113,239
RL	1.21	1.04	$ 7,101,355
G	0.96	1.04	$ 25,216,466
GU	N/A	N/A	$ 52,178
GS	1.50	1.25	$ 1,440,638
GL	1.73	1.43	$ 43,235,419
P	1.36	1.27	$ 14,828,247
T	19.08	9.20	$ (600,000)
SL	0.95	0.94	$ 5,285,457
PL	3.32	2.01	$ -

Table 9 - Electric Allocated Revenue by Rate Year[1194]

Revenue Allocated by Class (Electric)				
Class	**2024**	**2025**	**2026**	**Total**
R	$ 67,826,314	$ 21,718,095	$ 14,666,035	**$ 104,210,444**
RL	$ 3,588,442	$ 1,149,983	$ 776,573	**$ 5,514,998**
G	$ 12,752,954	$ 4,083,516	$ 2,757,562	**$ 19,594,032**
GU	$ 26,389	$ 8,450	$ 5,706	**$ 40,545**
GS	$ 727,980	$ 233,295	$ 157,542	**$ 1,118,817**
GL	$ 21,847,634	$ 7,001,478	$ 4,728,036	**$ 33,577,148**
P	$ 7,499,225	$ 2,401,264	$ 1,621,552	**$ 11,522,041**
T	$ (600,000)	$ -	$ -	**$ (600,000)**
SL	$ 2,673,062	$ 855,919	$ 577,994	**$ 4,106,975**
PL	$ -	$ -	$ -	**$ -**
Total	**$ 116,342,000**	**$ 37,452,000**	**$ 25,291,000**	**$ 179,085,000**

[1194] Allocated revenue amounts do not include reconciliation amounts.

Table 10 - Average Total Residential Bill Impact[1195]

Average Residential Bill Impact						
	Electric		**Gas**		**Electric and Gas**	
	$	**%**	**$**	**%**	**$**	**%**
2024	$ 4.08	3.01%	$ 10.43	11.54%	$ 14.51	6.42%
2025	$ 1.22	0.87%	$ 2.96	2.94%	$ 4.18	1.74%
2026	$ 0.34	0.24%	$ 2.80	2.70%	$ 3.14	1.29%

B. Gas Inter-class Cost Allocation

The allocation of costs among gas classes in this case contains two issues: the selection of a cost allocation method, and the question of the amount of future tax benefits to accelerate into this rate case. The latter issue is described above and will not be repeated herein, except in the decision section.

BGE

BGE's proposed allocation method is the same for gas as for electric, above, and a two-step method with a +/- 10 percent band is utilized.[1196] BGE does not allocate any additional revenue to Schedule PLG, which is significantly over-earning and closed to new customers.

Staff

Staff witness Thomas testified that he proposed a two-step allocation method.[1197] He testified that, like BGE witness Fiery, he excluded Schedule PLG from both steps because it was greatly over-earning.[1198] In his step 1, Mr. Thomas proposed to move the RROR's of Schedules IS and ISS halfway to 0.90 and to move the RROR of Schedule C

[1195] The Bill Impacts presented are inclusive of current energy rates and applicable gas charges.
[1196] Fiery Direct at 41-42.
[1197] Thomas Direct at 19.
[1198] *Id.*

to 0.90.[1199] In his step 2, Mr. Thomas proposed allocating the remaining revenue by each class's share of the forecasted 2024 baseline revenue and step 1 revenue allocation.[1200] He testified that the major difference in results between his and BGE's allocations was that BGE increased rates more aggressively for Schedules IS and ISS, while Staff's allocation was more gradual.[1201]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that BGE does not oppose Staff's step one allocations to Schedules IS and ISS.[1202] She testified that Staff's revenue allocation to Schedule C is incorrect and results in assigning more than three times more revenue than BGE because Staff's approach does not consider BGE's increasing rate base from the test year in the GCOSS and consequently over-allocates the step one increases needed to move customer classes toward an RROR of 0.90.[1203]

Staff Surrebuttal

In surrebuttal, Mr. Thomas testified that the difference in allocations for Schedule C can be attributed to how the step one amounts are determined, explaining that his approach accounts for the revenue increase and not the rate base increase.[1204] He testified that the additional revenue allocated to Schedule C in his step one will lessen the chance of Schedule C slipping below an RROR of 0.90 and is therefore preferable to BGE's proposed allocation.[1205]

[1199] *Id.*
[1200] *Id.* at 20, Table 10.
[1201] *Id.* at 19-20, Table 12.
[1202] Fiery Rebuttal at 21.
[1203] *Id.* at 22.
[1204] Thomas Surrebuttal at 5-6.
[1205] *Id.* at 6.

Mr. Thomas updated his allocations and proposed rates in surrebuttal but did not change his methods.[1206]

Commission Decision

As with electric, the Commission finds that the parties have not presented a compelling reason to depart from the approach it took in BGE's last rate case, Case No. 9645. In that case, the Commission ultimately elected to utilize a two-step unbanded allocation approach, which it noted has been the Commission's historic approach.

In this case, the Commission will also apply a similar approach, the same used for electric above: a first step applying 20 percent of the total increased revenue requirement to the classes with a UROR under 1.0, after adjusting net operating income for the incremental revenue increase, with the remainder applied to classes (with the exception of PLG) in proportion to their current revenue as a percentage of the total current revenue.

The available tax offsets total approximately $19 million for gas and are derived from an overcollection caused by the Tax Cuts and Jobs Act of 2017. The Commission directs that the full amount of remaining tax offsets, $19,648,000 shall be applied against the gas revenue requirement for the first year of rates under this case, rate year 2024.

The Commission will set rates for the MYP period for the next three years based on the following revenue requirements by year.

[1206] *Id.* at 16-18.

Table 11 - Gas Relative Rate of Return by Class

Resulting Relative Rate of Return (RROR)			
Class	Current RROR	Proposed RROR	Allocated Revenue over Course of MYP
D	1.10	0.99	$ 141,953,565
C	0.89	1.07	$ 90,439,489
ISS	0.52	0.74	$ 1,169,827
IS	0.53	0.77	$ 15,593,344
EG	1.09	0.89	$ 1,327,776
PLG	7.94	3.65	$ -

Table 12 - Gas Allocated Revenue by Rate Year[1207]

Revenue Allocated by Class (Gas)				
Class	**2024**	**2025**	**2026**	**Total**
D	$ 82,377,997	$ 24,245,857	$ 22,983,212	**$ 129,607,066**
C	$ 52,483,528	$ 15,447,185	$ 14,642,746	**$ 82,573,459**
ISS	$ 678,870	$ 199,808	$ 189,403	**$ 1,068,081**
IS	$ 9,049,075	$ 2,663,364	$ 2,524,665	**$ 14,237,104**
EG	$ 770,530	$ 226,786	$ 214,976	**$ 1,212,292**
PLG	$ -	$ -	$ -	**$ -**
Total	**$ 145,360,000**	**$ 42,783,000**	**$ 40,555,000**	**$ 228,698,000**

Table 13 - Average Total Residential Bill Impacts[1208]

Average Residential Bill Impact						
	Electric		**Gas**		**Electric and Gas**	
	$	**%**	**$**	**%**	**$**	**%**
2024	$ 4.08	3.01%	$ 10.43	11.54%	$ 14.51	6.42%
2025	$ 1.22	0.87%	$ 2.96	2.94%	$ 4.18	1.74%
2026	$ 0.34	0.24%	$ 2.80	2.70%	$ 3.14	1.29%

1207 Allocated revenue amounts do not include reconciliation amounts.
1208 Total Bill Impacts presented are inclusive of current energy rates and applicable gas charges.

C. Intra-class Revenue Allocation for Gas and Electric

BGE witness Fiery presented the Company's proposed electric and gas revenue allocations, rate designs, and tariff changes for BGE's MYP for the years 2024-2026, based on BGE's proposed revenue requirement.

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 Charge for electricity. Not all classes use each type of charge.

The Customer Charge is the fixed monthly charge on a customer's bill that is intended to recover the operating costs that are caused by customers connecting to the electric or gas distribution system. The Demand Charge is a charge for certain rate schedules that is based on the maximum load over a measured period of time and is designed to recover the costs driven by customer class' peak loads. The Delivery Service Charge is a volumetric charge meant to recover the costs caused by customers' usage (or the costs which vary as customer usage varies).

Various parties commented on elements of BGE's proposed rate design and tariffs, as follows:

1. Schedule SL Delivery Service Charge

BGE

In its Application, BGE witness Fiery proposed to allocate 40 percent of the incremental revenue requirement for Schedule SL to the Delivery Service Charge.[1209]

[1209] Fiery Rebuttal at 17-18.

Staff

Staff witness Hoppock recommended that the Commission accept his method to allocate 27 percent of the incremental revenue requirement for Schedule SL to the Delivery Service Charge, consistent with the approach taken in BGE's last rate case.[1210] Mr. Hoppock recommended recovering the remaining revenue through the other fixed charges.[1211] He further recommended that for Schedule SL, the reconciliation rate be displayed in $/Lamp-Watt rather than $/kWh, as agreed by BGE.[1212]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that Mr. Hoppock's proposal improves the rate design over the MYP period but does not go far enough to provide correct price signals.[1213] Ms. Fiery testified that her proposal of a 40 percent allocation provides a better price signal to install more efficient lighting technology and restores the prior rate design from before delivery charges were reduced as part of nuclear decommissioning and the Tax Cut and Jobs Act reductions.[1214] BGE witness Fiery testified that BGE agreed with the proposal to display the Schedule SL rate in $/Lamp-Watt.[1215]

Staff Surrebuttal

In surrebuttal, Mr. Hoppock testified that his proposed allocation is a more gradual way of reaching the same goal proposed by witness Fiery.[1216]

[1210] Hoppock Direct at 2, 74-75.
[1211] *Id.* at 75.
[1212] *Id.*
[1213] Fiery Rebuttal at 18.
[1214] *Id.* at 17-18.
[1215] *Id.* at 29.
[1216] Hoppock Surrebuttal at 5-6.

Commission Decision

The Commission finds that assigning a share of the Schedule SL incremental revenue requirement to the Delivery Service Charge would improve the price signaling and align with cost-causation. The Commission agrees with Staff and believes that BGE's proposed 40 percent allocation could result in rate shock. The Commission finds that Staff's proposed 27 percent allocation provides a more gradual approach for reaching those goals and is more consistent with the Commission's prior approach. The Schedule SL rate shall also be displayed in $/Lamp-Watt as agreed by the parties.

2. Schedule GS Participation Threshold

Staff witness Hoppock recommended that the Commission remove the 2,000 kWh usage threshold for participation in Schedule GS, which currently offers time-of-use SOS rates for Schedule G customers above the threshold.[1217] He testified that BGE has agreed to remove this usage threshold in the Schedule GS tariff.[1218] He testified that this change will expand opportunities for Schedule GS customers to participate in time-of-use rates.[1219]

Commission Decision

The Commission finds the undisputed recommendation of Staff to be reasonable. It shall therefore be adopted.

3. Schedule GL Rate Structure

Walmart

Walmart witness Kronauer testified that BGE's proposed Schedule GL does not reflect the underlying cost of service and shifts responsibility within the rate class by

[1217] Hoppock Direct at 3and 82.
[1218] *Id.* at 82.
[1219] *Id.*

charging customers for demand-related costs through delivery charges.[1220] He testified that BGE's proposal also increases risk to BGE because it makes revenue more dependent on customer usage, which depends on weather and the economy.[1221] He recommended that the Commission accept BGE's proposed customer charge and allocate the remaining revenue increase to the demand charge, but if the Commission approves a lower revenue requirement, that reduction should be applied to the energy charges.[1222]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that there are cost causative reasons to increase the demand charge at a higher percentage than the delivery charge, but this proposed rate design is not gradual enough compared to the rate designs that the Commission has historically accepted.[1223] She testified that BGE performed a bill analysis comparing its own proposal to that of Mr. Kronauer, included within her testimony, showing that Mr. Kronauer's proposal results in much greater bill variability for customers with different load factors across the class.[1224]

Staff Rebuttal

In rebuttal, Staff witness Hoppock testified that Walmart's proposed rate design is not gradual and would result in a 37.1 percent increase in the Schedule GL tariffed secondary service demand charge in rate year 1 and a 10.3 percent increase in the Schedule GL tariffed secondary delivery service charge.[1225] He testified that it would also diminish the current incentives for ratepayers to reduce consumption through distributed generation

[1220] Kronauer Direct at 28.
[1221] *Id.* at 31.
[1222] *Id.* at 31-32.
[1223] Fiery Rebuttal at 15.
[1224] *Id.* at 17.
[1225] Hoppock Rebuttal at 2-3.

and energy efficiency programs.[1226] He also testified that Schedule GL is subject to Rider 25, a revenue decoupling rider, which reduces the impact of weather and economic shifts on BGE's revenues.[1227]

Walmart Surrebuttal

In surrebuttal, Walmart witness Kronauer testified that, in his opinion, the differences in monthly bill impacts between Walmart and BGE's proposed Schedule GL are relatively modest, and he included a comparison chart.[1228] He reiterated that Walmart's proposal brings rates closer to their cost of service.[1229] He testified that Staff's concerns about energy efficiency incentives are overblown and that customers are already motivated to control use by the supply charges, which are volumetric.[1230]

Commission Decision

The Commission finds that the position of Staff and BGE to adopt a more gradual approach that maintains a strong conservation incentive is most in line with the Commission's prior ratemaking decisions and will best balance the competing ratemaking principles at issue. Although the Commission appreciates the concerns raised by Walmart regarding cost-causation, the Commission is unconvinced that supply charges alone provide sufficient incentive for customers to conserve energy. The Commission is also concerned that Walmart's proposal may have an undesirably large bill impact on some other customers of Schedule GL, as raised by BGE in its bill analysis.

[1226] *Id.* at 3.
[1227] *Id.* at 4.
[1228] Kronauer Surrebuttal at 4.
[1229] *Id.* at 5.
[1230] *Id.* at 6.

4. Electric Rider 34 and Gas Rider 18 - Accelerated Tax Benefits

Staff

Staff witness Hoppock recommended that electric Rider 34 offset rates be set to zero if the Commission approves an electric distribution revenue requirement with any revenue offset embedded.[1231] In parallel, Staff witness Thomas recommended that the Commission set gas Rider 18 offset rates to zero if the Commission approves a gas distribution revenue requirement with revenue offsets embedded or no revenue offsets.[1232]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that BGE did not object to Staff's proposed Rider 34 offset rates.[1233] She testified that this would diverge from the Commission decision in Order No. 89678 to display a separate offsetting credit amount on a customer's bill for added transparency.[1234]

Commission Decision

The Rider 34 and 18 offset rates shall reflect the full amount of those offsets, consistent with the approach taken in Case No. 9645.

5. Electric Rider 25 - Effective Rate Adjustments

BGE's application includes language for Electric Rider 25, a revenue decoupling mechanism that adjusts rates each month to account for variations caused by components such as weather, and to incentivize BGE to continue supporting conservation efforts by

[1231] Hoppock Direct at 67-68.
[1232] Thomas Direct at 37-38.
[1233] Fiery Rebuttal at 34.
[1234] *Id.*

reducing the link between revenues and customer usage. Similar riders have been approved for other utilities, including BGE in its prior rate case.

Staff

Staff witness Hoppock recommended that the Commission limit Rider 25, Effective Rate adjustments, to 10 percent of current rates and set the Rider 25 decoupling Monthly Rate Adjustments based on the distribution rates without the 10 percent cap.[1235] He explained that this would entail setting electric Rider 25 and gas Rider 8 test year base rate revenues without the 10 percent cap and making adjustments based on changes in the number of customers without the 10 percent cap.[1236] He testified that this was consistent with what was approved in Case No. 9655, Pepco's MYP, and ensures that BGE is allowed to collect its allowed revenue requirement while reducing rate shock.[1237]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that this proposal sets the current effective base distribution rates at levels too low to generate the full revenue requirement and instead collects a portion of base distribution revenue via the decoupling mechanism of the Rider 25 Monthly Rate Adjustment, which is intended to adjust rates for changes in usage and customers and not be a primary method for recovery of the revenue requirement.[1238] She testified that this could also lead to customer confusion as well as confusion for rate design in subsequent rate cases.[1239]

[1235] Hoppock Direct at 71.
[1236] *Id. at* n 247.
[1237] *Id.* at 2, 68, and 71.
[1238] Fiery Rebuttal at 32.
[1239] *Id.* at 33.

Staff Surrebuttal

In surrebuttal, Mr. Hoppock testified that both Pepco and DPL have MYPs that incorporate 10 percent caps on Effective Rate Adjustments.[1240] He testified that in all MYPs to date with approved or proposed Effective Rate Adjustment caps, the cap has only applied in year 1 of the MYP, but if the cap were in effect in the final year of the MYP, this could be accounted for in rates.[1241] He testified that, although BGE has proposed a year 1 offset, Staff's proposed rate design, including Rider 25 decoupling, does result in BGE receiving the approved revenue requirement.[1242]

Commission Decision

The Commission finds that Staff's recommendations regarding Rider 25 are reasonable and consistent with the Commission's approach in prior cases and should be adopted. The Commission is concerned that BGE's proposal would intentionally set it apart from other utilities in the treatment of this issue without a clear basis for that unique treatment. The Commission is unpersuaded by BGE's claim that Staff's proposal would prevent BGE from recovering its full revenue requirement. The use of rate adjustments in Rider 25 is not a guarantee of BGE's authorized revenue requirement. Staff's proposal fairly balances the goals of incentivizing energy efficiency and correcting for weather variation with the need to provide predictable rates to customers.

[1240] Hoppock Surrebuttal at 9-10, citing Case Nos. 9655 and 9681.
[1241] Hoppock Surrebuttal at 10-11.
[1242] *Id.* at 10.

6. Income Tax Adjustment Rider

BGE

In its application, BGE proposed an Income Tax Adjustment ("ITA") Rider, through electric Rider 29 and gas Rider 17, that would adjust revenue in the event of a major change in BGE's tax rates.

OPC

OPC witness Nelson recommended that the Commission reject BGE's proposed Income Tax Adjustment Rider.[1243] He testified that a rider should only be used for costs that are large, volatile, and largely beyond the control of the utility.[1244] He testified that, while taxes are large and outside utility control, they are predictable and connected to a utility's standard forecasting practices.[1245] He testified that rider recovery could create asymmetry within the regulatory framework, assuming that BGE is unlikely to propose riders for costs it believes will decrease over time.[1246]

Staff

Staff witness Hoppock also recommended that the Commission reject the proposed tariff language for BGE's proposed Income Tax Adjustment Rider.[1247] He testified that those proposed riders would have the effect of making rates effective within 10 days of filing or the effective date the new tax rates take effect and pre-determining the revenue allocation and rider rate design.[1248] He testified that, in his opinion, this would not allow sufficient time for the Commission to review the proposed rider rates and supporting

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[1243] Nelson Direct at 4.
[1244] *Id.* at 32.
[1245] *Id.*
[1246] *Id.* at 33.
[1247] Hoppock Direct at 2.
[1248] *Id.* at 2-3.

workpapers, removes the Commission's authority to approve rider rates, and does not offer flexibility regarding revenue allocation and rate design.[1249] He testified that BGE's proposal would also prevent the Commission from accounting for factors, such as changes in customer counts, which may arise.[1250]

<u>BGE Rebuttal</u>

In rebuttal, BGE witness Frain testified that when it previously suggested an ITA rider, the Commission questioned the necessity of such a rider absent federal taxation changes and outside of a rate case.[1251] He testified that the Inflation Reduction Act of 2022 and pending guidance for the consideration of the tax repairs deduction in the corporate alternative minimum tax justifies consideration of the rider at this time.[1252] He testified that the riders are a superior method to relying on reconciliation because tax changes can have significant impacts on revenue requirements, and waiting for reconciliation could mean accumulating large variances that need to be collected/returned in reconciliation.[1253] He testified that the ITA riders are designed to allow rates to respond gradually and reduce rate shock from large reconciliation charges when moving between rate cases.[1254] He testified that tax changes are out of BGE's control and are large and volatile, thus justifying the use of a rider.[1255] He testified that the ITA riders are proposed to symmetrically adjust rates up or down in response to tax changes.[1256]

[1249] *Id.* at 77.
[1250] *Id.*
[1251] Frain Rebuttal at 21-22, citing Case No. 9664, Proposed Order of Public Utility Law Judge, approved by the Commission in Order No. 90001.
[1252] Frain Rebuttal at 21-22.
[1253] *Id.* at 22-23.
[1254] *Id.*
[1255] *Id.* at 23-24.
[1256] *Id.* at 24.

Also in rebuttal, BGE witness Fiery testified that BGE is willing to modify its proposed ITA rider such that it would file for the new rider rates prior to the tax change taking effect, allowing the Commission the flexibility and additional time to review the rate change and evaluate whether the revenue requirement difference resulting from the tax rate change is sufficiently significant to warrant inclusion in the ITA riders.[1257] She testified that BGE's proposed tariff language is consistent with how it allocates other rider true-up revenues and how the Commission determined the revenue requirement should be allocated in the last rate case, thus alleviating the administrative burden of determining the allocation in the future if a tax rate change is enacted and an adjustment is necessary.[1258]

OPC Surrebuttal

In surrebuttal, Mr. Nelson testified that BGE witness Frain has not demonstrated that tax repairs are unrelated to the utility's income and does not recognize the risk that BGE will propose riders with asymmetric risk.[1259] He testified that the Commission could create a one-way tax refund adjustment that only refunds customers for the revenues that they are owed but does not result in additional charges.[1260]

Staff Surrebuttal

In surrebuttal, Mr. Hoppock testified that BGE has not proposed revised ITA Rider tariff language addressing his concerns.[1261] He recommended that the Commission reject any tariff language that limits the Commission's discretion over the time it has to consider a filing or that sets new rates if the Commission takes no action within a timeframe stated

[1257] Fiery Rebuttal at 31.
[1258] *Id.*
[1259] Nelson Surrebuttal at 19.
[1260] *Id.* at 19-20.
[1261] Hoppock Surrebuttal at 6-7.

within the tariff language.[1262] He also recommended that the Commission reject any tariff language that pre-determines the revenue allocation or rate design.[1263] He testified that, by comparison, BGE's MYP Adjustment Rider (the true-up and reconciliation mechanism) does not specify an allocation method and leaves that determination to the Commission.[1264]

Commission Decision

The Commission finds that BGE's novel proposal raises too many concerns and offers too few benefits and should therefore be rejected. Although the Commission acknowledges that possible changes in tax law could impact BGE, and BGE ratepayers, the Commission is unpersuaded by the necessity of the proposed rider. There have been prior tax changes before, and the Commission has handled the effects on ratepayers and utilities as appropriate at the time and given the circumstances surrounding the tax changes. The Commission is concerned at the possibility of a mechanism approved in a rate case that could pre-commit the Commission as to how to handle a change in the tax code, without knowing the context in which such a change may occur.

7. Site Not Ready Fees

BGE

As part of its application, BGE proposed amended gas and electric tariff language concerning Site Not Ready fees, stating that the customer is responsible for paying any costs incurred by BGE when BGE arrives at a construction site at a mutually agreed date and the site is not ready for construction.[1265]

[1262] *Id.* at 7.
[1263] *Id.* at 7-8.
[1264] *Id.*
[1265] Fiery Direct at 65.

Staff

Staff witness Hoppock recommended that the Commission accept BGE's proposed Site Not Ready fees.[1266] He testified that this proposal is consistent with cost causation.[1267]

Mr. Hoppock also recommended the Commission require BGE to state the fees in their tariffs, in order to reduce misunderstandings and provide a clear price signal so that customers understand the consequences of not abiding with previously agreed construction schedules.[1268] He testified that this is consistent with electric tariff section 8.2 and 8.23.[1269]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that BGE negotiates the Site Not Ready Fees with contractors on a routine basis and that Staff's proposal would require additional filings to keep updated fees in the tariff.[1270] She testified that, as an alternative, BGE could offer transparency regarding fees by providing the accurate fee to the customer through company materials as well as when construction plans are discussed and finalized.[1271]

Staff Surrebuttal

In surrebuttal, Mr. Hoppock testified BGE makes multiple filings on a routine basis, such as SOS administrative charges and transmission rates, and could also file updated Site Not Ready Fees.[1272]

[1266] Hoppock Direct at 3 and 79.
[1267] *Id.* at 80.
[1268] *Id.* at 3 and 79-80.
[1269] *Id.* at 80.
[1270] Fiery Rebuttal at 36.
[1271] *Id.*
[1272] Hoppock Surrebuttal at 14-15.

Commission Decision

The Commission finds that Staff's proposal, requiring that Site Not Ready Fees appear in BGE's tariff, will further the interest of transparency without unreasonably burdening BGE, which already makes a number of routine filings. The Commission otherwise accepts BGE's proposal for these fees.

8. Class R and G Smart Meters

BGE

In its application, BGE stated that it was no longer able to source net-metering compatible non-smart meters and proposed that future net metering customers should be required to accept an AMI smart meter.

Staff

Staff witness Hoppock recommended that the Commission reject BGE's proposal to require a smart meter for participation in net metering.[1273] He testified that this proposal is inconsistent with BGE Rider 27, which allows Schedule R and G customers to opt-out of having a smart meter.[1274] He testified that BGE has not fully examined if there are other Commission-approved non-smart meters that it could use for net metering customers who do not want a smart meter.[1275] He recommended that BGE should demonstrate that other non-smart meter options are not viable for net metering if the Commission were to take BGE's recommendation.[1276] He also testified that BGE's proposal to grandfather existing

[1273] Hoppock Direct at 3, 80.
[1274] *Id.* at 80.
[1275] *Id.* at 80-81.
[1276] *Id.* at 81.

non-smart net metering customers is inconsistent with BGE's proposed tariff language, which does not allow for grandfathering.[1277]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that BGE has found one possible solution to the lack of availability of net metering capable non-AMI meters and is currently conducting testing on new meters.[1278] She testified that, for the time being, BGE is agreeable to the rejection of its smart meter requirement for net metering.[1279] She testified that BGE currently has no new inventory of non-smart meters capable of net metering, and any new net metering customer wishing to opt-out of a smart meter will be unable to do so until the inventory problem is resolved.[1280]

Staff Surrebuttal

In surrebuttal, Mr. Hoppock testified in the event that a Rider 27 smart meter opt-out customer requests net metering and insists on not receiving a smart meter, BGE would need to file a request for a temporary exemption.[1281]

Commission Decision

Given BGE's agreement to Staff's position, the Commission rejects BGE's proposal to add a smart metering requirement to the net metering rider. The Commission directs BGE to make a filing within the earlier of 90 days of this order or whenever it locates an acceptable meter replacement, informing the Commission of the status of this

[1277] *Id.*
[1278] Fiery Rebuttal at 34.
[1279] *Id.*
[1280] *Id.* at 34-35.
[1281] Hoppock Surrebuttal at 12.

issue, with an additional filing every 90 days thereafter until a replacement is made available for customers.

9. Employee Training Customer Charge

IBEW

IBEW witness Jacobs recommended that the Commission approve a special customer charge to provide dedicated funds to increase hiring.[1282] He testified that BGE must expend a substantial amount of money to train employees to ensure that they are fully qualified and capable of replacing more seasoned employees.[1283]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that Mr. Jacobs' proposal goes against cost causation because customer charges are used to collect fixed costs, not costs associated with hiring and staffing.[1284]

Commission Decision

The Commission finds that IBEW's proposal for an employee training customer charge is inconsistent with cost causation and not based on any historic Commission practice. It is therefore rejected.

10. Schedule C Declining Block Rate Structure

BGE

In its Application, BGE proposed continuing the existing declining block rate structure of the Schedule C delivery charge, which results in distribution rates being larger

[1282] Jacobs Direct at 14-15.
[1283] *Id.* at 14.
[1284] Fiery Rebuttal at 13-14.

for the first 10,000 therms of usage per month and smaller for the usage in excess of 10,000 therms per month.

Staff

Staff witness Thomas testified that he disagreed with BGE's proposed declining block rate structure for the Schedule C delivery charge.[1285] He recommended phasing out the declining block structure over the course of the three rate years of this MYP, ultimately resulting in a flat rate structure for Schedule C beginning in rate year 3.[1286] He testified that the Commission has previously disfavored declining block rates because they do not incentivize conservation.[1287] He testified that this change would also apply to the interruptible service (IS and ISS) schedules along with schedule EG through the Optional Firm Delivery Service, which mirrors the Schedule C firm delivery rates.[1288]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that BGE does not oppose the elimination of the declining block rate structure in the next rate case but needs additional time to run a GCOSS to analyze if a new "large customer" rate schedule is needed for customers whose usage currently exceeds 10,000 therms per month.[1289] She testified that the removal of the block structure in the current rate case would otherwise be far from gradual for these larger customers.[1290]

[1285] Thomas Direct at 30.
[1286] *Id.* at 31.
[1287] *Id.*, citing case No. 9651, Order No. 89779 at 36-7; Case No. 9490, Order No. 89072 at 109.
[1288] Thomas Direct at 31-32.
[1289] Fiery Rebuttal at 27-28.
[1290] *Id.* at 28.

Staff Surrebuttal

In surrebuttal, Mr. Thomas testified that he supported BGE's proposal to conduct an analysis of Schedule C on the question of whether a large customer C class is needed, but deferring his recommendation to eliminate the declining block rate structure would defer the benefits of incentivizing greater energy efficiency in Schedule C.[1291]

Commission Decision

The Commission finds that Staff's proposal may bring consistency across comparable rate classes among different utilities and could support greater conservation. However, the Commission is concerned that the record does not contain an analysis of Schedule C that would provide insight into the impact and fairness of Staff's proposal. Staff's proposal is therefore denied. BGE, in consultation with Staff, is directed to conduct an analysis of Schedule C and produce a revised Cost of Service Study to determine if this rate class still adequately represents the customer base and if a new "Large Commercial" rate schedule is needed for customers in their next base rate case. The Commission also directs BGE to conduct a study on the rate impacts and the amount of "rate shock" that Schedule C customers will incur with the removal of the current declining block rate structure, as well as a proposal to eliminate this rate structure altogether for all customer classes in their next base rate case.

11. Gas Line Extension Fees

OPC

OPC witness Nelson recommended that the Commission sunset the current practice of ratepayer subsidization of line extension allowances which furthers the expansion of the

[1291] Thomas Surrebuttal at 11.

natural gas system by covering a portion of the cost of extending main and service lines to new customers.[1292] He testified that this practice has been phased out in California and is being reduced in Oregon, Washington State, and New York.[1293]

Mr. Nelson testified that, despite BGE's claims that they do not offer line extension allowances, BGE actually does cover the costs of line extensions when it estimates that a project will produce more revenues than costs over a 30-year period.[1294] He testified that BGE also provides a standard allowance of 150 feet of service line extension for new customers that do not require a main line extension.[1295] He testified that BGE was forecasted to spend approximately $70.5 million on line extensions in 2023, with increasing estimates in subsequent years.[1296] Mr. Nelson testified that service lines used to serve a single customer should not be socialized across all ratepayers and that subsidies for line extensions distort the decisions of customers in favor of using gas and are not in the public interest.[1297] He testified that the 30-year amortization used by BGE is not justified given the uncertain future of the gas system.[1298]

<u>BGE Rebuttal</u>

In Rebuttal, BGE witness Case recommended the Commission reject OPC's proposal.[1299] He testified that BGE's current economic test is intended to ensure that there is no subsidization/socialization between existing gas customers and new gas

[1292] Nelson Direct at 34.
[1293] *Id.* at 35-36.
[1294] *Id.* at 36.
[1295] *Id.* at 37.
[1296] *Id.* at 37-38.
[1297] *Id.* at 38-39.
[1298] *Id.* at 39-40.
[1299] Case Rebuttal at 106.

customers.[1300] He testified that new customers help existing customers by spreading the rate base over a large number of customers.[1301] He testified that the expected revenue from line extensions has historically been $25 million more than the estimated cost of the projects.[1302] He recommended that any policy change on gas line extensions should be made via a work group that includes a broader group of stakeholders and testified that other jurisdictions that have undertaken this policy have done so in a broader manner, not in a rate case.[1303]

IBEW Rebuttal

In Rebuttal, IBEW witness Jacobs testified that customers, builders, and developers rely on this allowance, and it would be unfair to remove it without proper notice and comment.[1304]

Staff Surrebuttal

In surrebuttal, Staff witness Hoppock recommended that the Commission examine gas line extension policy in a wider forum, such as a working group, that examines the issue at a statewide level.[1305]

OPC Surrebuttal

In surrebuttal, Mr. Nelson testified that BGE has failed to respond to the concern that its gas line extension policy and 30 year replacement period, while historically appropriate, is inappropriate under BGE's present decarbonization strategy, which risks

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[1300] *Id.* at 105.
[1301] *Id.*
[1302] *Id.* at 106.
[1303] *Id.* at 106-108.
[1304] Jacobs Rebuttal at 2.
[1305] Hoppock Surrebuttal at 16.

stranding assets long before their projected lifespan.[1306] He testified that there is sufficient information to know that subsidizing expansion of gas is an increasingly risky prospect for ratepayers in today's evolving industry and does not require significant investigation before implementation given the substantial amounts that are forecasted to be spent in this rate case on gas line extensions.[1307]

Commission Decision

The Commission finds that this decision should be made on a statewide basis, with full participation of all stakeholders, rather than in a piecemeal fashion as rate cases arise. OPC's proposal is therefore rejected without prejudice. OPC may raise the issue in the Commission's ongoing proceeding addressing the future of natural gas in Maryland, Case No. 9707.

12. Large Load Interconnections

Walmart

Walmart witness Kronauer recommended that the Commission more tightly define a "large load" customer for the purposes of a BGE proposal to begin recovering certain electric service extension costs on a case-by-case basis from new customers taking service under Schedules P or T.[1308] Mr. Kronauer testified that BGE's current proposal could potentially apply to electric vehicle charging infrastructure.[1309] Mr. Kronauer recommended that defining "large load" as a 25+ MVa customer would prevent EV infrastructure deployment from being subject to potential delays and costs.[1310]

[1306] Nelson Surrebuttal at 22-23.
[1307] *Id.* at 24-25.
[1308] Kronauer Direct at 20-22.
[1309] *Id.* at 21.
[1310] *Id.* at 22.

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that BGE has begun to see requests for larger load service which give rise to customer and situation-specific risks that are best addressed on a case-by-case basis and are not entirely driven by load size.[1311] She recommended that the Commission reject Walmart's proposal.[1312]

Commission Decision

The Commission finds that Walmart's proposal raises statewide issues that would be better addressed uniformly for all utilities. Walmart's proposal is therefore rejected without prejudice. Walmart may make a separate filing requesting the Commission address this issue outside of a rate case.

13. Remaining Customer Charges

BGE

In its application, BGE proposed increasing customer charges as follows:

Table 14

BGE Customer Charge Proposal for Electric					
Class	Cost	Current	2024	2025	2026
R and RD	$ 16.78	$ 9.00	$ 9.25	$ 9.50	$ 10.00
G and GP	$ 28.96	$ 14.00	$ 14.60	$ 15.30	$ 16.00

Table 15

BGE Customer Charge Proposal for Gas					
Class	Cost	Current	2024	2025	2026
D	$ 26.03	$ 15.25	$ 15.75	$ 16.25	$ 16.75
C	$ 113.28	$ 38.00	$ 39.00	$ 40.00	$ 41.00
ISS	$ 791.97	$ 375.00	$ 390.00	$ 400.00	$ 410.00

[1311] Fiery Rebuttal at 35.
[1312] *Id.* at 35-36.

OPC

OPC witness Nelson recommended that the Commission reject BGE's proposed customer charge increases for residential gas and electric customers for Schedules R, RD and D.[1313] He argued that they contradict Commission precedent and state policy goals and that they would disproportionately harm low-usage customers who tend to be low-income.[1314]

Staff

Staff witness Hoppock recommended that the Commission accept BGE's proposed Schedule R customer charge increase, with an adjustment to the manner in which the Schedule R customer charge increases over the three years of this case, going to a more gradual increase over time.[1315]

Staff witness Hoppock recommended a gradual $1.60 increase for the Schedule G customer charge over the current rate, which results in an increase by the same amount as in Case No. 9645, BGE's last rate case.[1316]

Staff witness Thomas testified that BGE's proposed increases of gas customer charges for Schedules D, C, and ISS were higher than those the Commission has historically approved.[1317] Mr. Thomas recommended smaller increases in customer charges.[1318] Mr. Thomas agreed with BGE's proposal to not increase customer charges for Schedules IS and EG.[1319]

1313 Nelson Direct at 30.
1314 *Id.* at 4, 21, and 26-27.
1315 Hoppock Direct at 68 and 71.
1316 *Id.* at 68 and 71-72.
1317 Thomas Direct at 23-24.
1318 *Id.* at 24-26, Tables 17-18.
1319 *Id.* at 26.

Walmart

Walmart witness Kronauer recommended the Commission approve BGE's proposed Schedule C rate structure, which remains unchanged from the prior rate case.[1320] He recommended that the Commission allocate any revenue increase for Schedule C to the customer charge until it reaches parity with BGE's GCOSS, then proportionally through the delivery charges, with any reduction by the Commission from BGE's requested revenue requirement being applied as a reduction to the delivery charges.[1321]

BGE Rebuttal

In rebuttal, BGE witness Fiery testified that OPC's position against increasing the customer charge goes against cost causation because failing to recover fixed costs through fixed charges results in intra-class inequities as higher-using customers subsidize the fixed costs of serving lower-using customers.[1322] She testified that BGE's proposed customer charge increases are not expected to disproportionately affect customers with limited incomes because usage by customers is not significantly different between limited-income customers and other customers.[1323] She testified that BGE's proposed Schedule D customer charge increase would result in only slight changes in the percentage of the average bill that are variable charges, thus having no meaningful impact on the price signals encouraging energy conservation.[1324]

BGE witness Fiery testified that BGE supported Staff's proposal to increase the schedule R electric customer charge gradually.[1325] Ms. Fiery testified that Staff's proposed

[1320] Kronauer Direct at 33.
[1321] *Id.*
[1322] Fiery Rebuttal at 11-12.
[1323] *Id.* at 12-13.
[1324] *Id.* at 26.
[1325] *Id.* at 9-10.

gas customer charge increases are too small to meaningfully improve the overall rate design to be more aligned with the GCOSS.[1326] She testified that BGE's proposed customer charge increases are consistent with the amounts the Commission has approved in recent rate cases where it has approved customer charge increases.[1327]

BGE witness Fiery testified that Walmart's proposed change to the Schedule C customer charge would support cost causation but would be insufficiently gradual given past Commission increases.[1328]

BGE witness Fiery recommended that the Commission adopt her $2.00 customer charge increase for Schedule G and testified that it is appropriate to move the G and GS schedules closer to alignment because the only remaining difference between them is the commodity rate.[1329]

OPC Surrebuttal

In surrebuttal, Mr. Nelson testified that customer charge increases do not reflect cost causation because BGE has, in his opinion, mis-classified some distribution plant expenses as customer-related rather than demand-related.[1330] He testified that BGE mis-classified costs related to service lines, service regulators, and meters, all of which are sized based on peak load.[1331] He testified that BGE has an incentive to shift revenue into the customer charge in order to stabilize revenue.[1332] He testified that, although rate changes may be small for individual customers, they can have large impacts across the customer

[1326] *Id.* at 25.
[1327] *Id.*
[1328] *Id.* at 26-27.
[1329] *Id.* at 10.
[1330] Nelson Surrebuttal at 5.
[1331] *Id.* at 5-8.
[1332] *Id.* at 8.

base, and incremental increases add up over time.[1333] He testified that the larger proposed increase, by BGE, in the gas customer charge versus the electric weakens the incentive to electrify.[1334] He testified that electrification can best be achieved through specific electricity rates designed for that purpose.[1335] Mr. Nelson also testified that BGE's analysis showing that low-usage customers are not necessarily low-income fails to consider income trends or multiple years.[1336] He testified that regional energy usage and income data shows a clear and consistent relationship between income and energy usage.[1337] He also testified that making comparisons based only on the receipt of energy assistance is an inappropriate proxy for determining energy usage among all lower income customers because energy assistance customers use more energy than non-energy assistance low-income customers.[1338]

Staff Surrebuttal

In surrebuttal, Mr. Hoppock testified that his proposal regarding Schedule G is in line with the increase approved in BGE's last rate case.[1339]

In surrebuttal, Mr. Thomas testified that BGE's analysis of prior cases errs in not including cases where a customer charge increase was not approved or that involved a settlement.[1340] He testified that his proposal for smaller increases gives customers more control over their bill through energy efficiency.[1341]

[1333] *Id.* at 11.
[1334] *Id.* at 13-14.
[1335] *Id.* at 14.
[1336] *Id.* at 15.
[1337] *Id.* at 15-16.
[1338] *Id.* at 16.
[1339] Hoppock Surrebuttal at 4.
[1340] Thomas Surrebuttal at 8.
[1341] *Id.*

Commission Decision

Regarding the residential electric customer charges – classes R and RD – the Commission finds that Staff's proposal, supported by BGE, is the most reasonable balance between the need to respect cost causation and the need for gradualism when handling residential customer rates. The Commission appreciates the concerns raised by OPC regarding low-income customers. However, a policy of zero movement on customer charges that are already well below the estimated cost of service would unreasonably elevate one principle of ratemaking above all others and would result, given rising rates overall, in an effective decrease in the customer charge, moving it still further out of alignment with cost causation. Although OPC witness Nelson claimed that BGE's cost causation estimates are erroneous, the Commission notes that OPC did not offer a witness challenging BGE's cost of service study, and its argument regarding mis-classification of costs did not appear in testimony until Mr. Nelson's surrebuttal. The Commission finds that the argument is not persuasively supported by the record nor was it properly and timely raised.

Regarding gas classes D, C, and ISS, the Commission notes that BGE's proposal would increase the trend of customer charge increases faster than recent Commission decisions, when all cases are taken into account. Staff's proposal more accurately follows that historic trend. As noted above, OPC's proposal to halt increases in the residential customer charge entirely is too extreme, given that the customer charge is already well below that called for in the cost of service study. Walmart's proposal for Class C would significantly exceed the historic trend and could result in rate shock for some customers in Schedule C. The Commission finds that Staff's proposals are most preferable, given the economic environment and the need to minimize additional rate shock on top of rising rates, while still allowing customer charges to grow in line with recent trends.

Regarding class G, the Commission finds that Staff's proposed gradual approach is preferable to BGE's proposal because it reduces the risk of rate shock and follows the pattern of BGE's last rate case, while still moving class G's rate design closer to its cost of service.

The Commission accepts BGE's remaining customer charges not addressed above as uncontested.

Customer charges for rate years 2024, 2025, and 2026 will be as follows:

Table 16

Electric Customer Charges				
Customer Class	**Current**	**2024**	**2025**	**2026**
R	$ 9.00	$ 9.30	$ 9.65	$ 10.00
RL	$ 12.00	$ 12.00	$ 12.00	$ 12.00
RD	$ 9.00	$ 9.30	$ 9.65	$ 10.00
G/GP	$ 14.00	$ 14.55	$ 15.10	$ 15.60
GU	$ 6.00	$ 6.00	$ 6.00	$ 6.00
GS	$ 18.60	$ 18.60	$ 18.60	$ 18.60
GL/GLP	$ 97.00	$ 97.00	$ 97.00	$ 97.00
P	$ 660.00	$ 660.00	$ 660.00	$ 660.00
T	$ 2,400.00	$ 2,400.00	$ 2,400.00	$ 2,400.00

Table 17

Gas Customer Charges				
Customer Class	**Current**	**2024**	**2025**	**2026**
D	$ 15.25	$ 15.55	$ 15.85	$ 16.15
C	$ 38.00	$ 38.35	$ 38.70	$ 39.05
IS	$ 1,250.00	$ 1,250.00	$ 1,250.00	$ 1,250.00
ISS	$ 375.00	$ 378.00	$ 381.00	$ 384.00
EG	$ 3,000.00	$ 3,000.00	$ 3,000.00	$ 3,000.00

Table 18 - Resulting Bill Impacts[1342]

Average Total Residential Bill Impact						
	Electric		Gas		Electric and Gas	
	$	%	$	%	$	%
2024	$ 4.08	3.01%	$ 10.43	11.54%	$ 14.51	6.42%
2025	$ 1.22	0.87%	$ 2.96	2.94%	$ 4.18	1.74%
2026	$ 0.34	0.24%	$ 2.80	2.70%	$ 3.14	1.29%

IT IS THEREFORE, this 14th day of December, in the year Two Thousand Twenty-Three, by the Public Service Commission of Maryland, **ORDERED**:

(1) that the Application of Baltimore Gas and Electric Company, filed on February 17, 2023 (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, 2024, January 1, 2025, and January 1, 2026, 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:

[1342] The bill impacts shown are total bill impacts inclusive of current energy rates and gas charges.

Table 19

Electric	Incremental			Total	
	Before Offsets	Accelerated Tax Benefit	Incremental Base Rate	2021/2022 Reconciliation	Total Rate Recovery
2024	$116,342	-$75,687	$40,655	$52,188	$92,843
2025	$32,148	$80,991	$113,139	$0	$153,794
2026	$25,291	$0	$25,291	$0	$179,085

Table 20

Gas	Incremental			Total	
	Before Offsets	Accelerated Tax Benefit	Incremental Base Rate	2021/2022 Reconciliation	Total Rate Recovery
2024	$145,360	-$19,684	$125,676	$21,786	$147,462
2025	$41,410	$21,057	$62,467	$0	$188,143
2026	$40,555	$0	$40,555	$0	$228,698

Table 21

Electric + Gas	Incremental			Total	
	Before Offsets	Accelerated Tax Benefit	Incremental Base Rate	2021/2022 Reconciliation	Total Rate Recovery
2024	$261,702	-$95,371	$166,331	$73,974	$240,305
2025	$73,558	$102,048	$175,606	$0	$341,937
2026	$65,846	$0	$65,846	$0	$407,783

(3) that BGE is directed to accelerate the return of certain customer monies in rate year 2024, as directed above;

(4) that BGE is authorized to collect reconciliation amounts in rate years 2024 and 2025, as directed above;

(5) that OPC's request to terminate the instant MYP proceeding and convert it to a traditional rate case is denied;

(6) that PBWLDC's request to condition approval of BGE's MYP application on a demonstration by BGE of compliance with PUA § 5-305 is denied;

(7) that in its next rate case application, BGE is directed to demonstrate that contracting labor was procured in compliance with PUA § 5-305, as described above;

(8) that until further direction of the Commission, BGE is directed to include in all future rate case applications an ongoing benefit cost analysis of its conduit agreement with Baltimore City until the costs of the contract are fully recovered, including benchmarking against any new contract BGE enters into with Baltimore City;

(9) that BGE is directed to file with the Commission within 180 days of this Order the details of its EM&V plan to study benefits enumerated in its NTIA application and the appropriateness of expanding fiber, as described above;

(10) that BGE is directed to include in its next rate case application all documentation used for internal management approval of its EAM 2.0 Project, as described above, and to provide that documentation to Staff prior to implementation of the selected solution;

(11) that BGE is directed to provide to Staff the requested information regarding Project 84816, as described above, as soon as it becomes available;

(12) that the PC44 EV Workgroup is directed to provide a recommendation to the Commission regarding the concerns raised herein with the EV BCA methodology, by June 3, 2024;

(13) that BGE's request that Phase 1 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 MYP rate-effective period;

(14) 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

(15) that all motions or requests not granted herein are denied.

/s/ Fredrick H. Hoover, Jr.

/s/ Michael T. Richard

/s/ Anthony J. O'Donnell

/s/ Kumar P. Barve

/s/ Bonnie A. Suchman
Commissioners