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August 14, 2020

Mr. Andrew S. Johnston
Executive Secretary
Public Service Commission
Of Maryland
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Re: CN 9645 -- BGE MRP -- Direct Testimony of OPC Witnesses Roberto, Larkin-Connolly, and Alvarez/Stephens (Public)

Dear Mr. Johnston:

Enclosed for filing, please find the Direct Testimonies of Office of People's Counsel ("OPC") witnesses Cheryl Roberto and Brendan Larkin-Connolly and the Public Version of the Direct Testimony of OPC witness panel Paul Alvarez and Dennis Stephens.

Should you have any questions, please do not hesitate to contact me.

Respectfully submitted,

/electronic signature/
Joseph G. Cleaver
Senior Assistant People's Counsel

JGC:eom
Enclosure
cc: All Parties of Record (PSC Service List Case No. 9645)

BEFORE THE
PUBLIC SERVICE COMMISSION OF MARYLAND

In the matter of the Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan.

Case No. 9645

Direct Testimony of
Cheryl Roberto

On Behalf of
Office of People's Counsel

August 14, 2020

LIST OF ATTACHMENTS

Attachment CR 1: Resume of Cheryl Roberto

Attachment CR 2: Whited, Melissa and Cheryl Roberto. 2019. *Multi-Year Rate Plans: Core Elements and Case Studies*, Prepared for Maryland PC51 and Case 9618

I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, title, and employer.

A My name is Cheryl Roberto. I am employed by Synapse Energy Economics, Inc. as a Senior Principal. My business address is 485 Massachusetts Avenue, Cambridge, MA 02139.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in electricity industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q Please summarize your professional and educational experience.

A For more than 30 years I have managed, regulated, or guided the operation of utilities and regulatory policy related to public utilities. From 2008 until 2012, I served as a Commissioner of the Public Utilities Commission of Ohio, where I initiated a national pilot partnership with the U.S. Department of Energy to support cost-effective deployment of combined heat and power systems. I served as Co-Chair of the 2012 National Electricity Forum. As a member of the National Association of Regulatory Utility Commissioners, I served on the Task Force on Environmental Regulation and Generation, the Committee on Electricity, and Vice Chair of the Committee on Critical Infrastructure. Immediately after my service as a Commissioner, I led a nation-wide program advocating for regulatory reform as Associate Vice President of the Environmental Defense Fund's Clean Energy Program. The goal of the program was accelerating the adoption of renewable energy technologies; modernizing U.S. energy infrastructure; and eliminating financial and regulatory barriers that prevent widespread implementation of renewables, energy efficiency, and innovative energy generation and distribution approaches. Prior to my service as a Commissioner, I led the Department of Public Utilities for the City of Columbus as its Director, serving, with a staff of 1,300, the 1.1 million residents of the Central Ohio region. From 1987 through 2000, I practiced law as an Assistant Attorney General in Ohio, Assistant Counsel in Pennsylvania, and Assistant City Attorney in Columbus, Ohio. I hold a B.A. in Political Science from Kent State University, and a J.D. from the Moritz College of Law at The Ohio State University. My resume is attached hereto as Attachment CR-1.

Q **On whose behalf are you testifying in this case?**

A I am appearing on behalf of the Office of People's Counsel.

Q **Have you testified previously before the Public Service Commission of Maryland or participated in any Commission-sponsored proceeding?**

A I have not testified before the Public Service Commission of Maryland ("Commission") but I did provide expert guidance to the Maryland Office of People's Counsel ("OPC") during Phase I of the working group effort established by the Commission in Case No. 9618 regarding the processes and procedures for multi-year rate plans ("MRP") including participating in the working group discussions.

Q **Have you testified previously before any other tribunals?**

A Yes. I have previously appeared before Federal Energy Regulatory Commission and the U.S. Senate Energy and Natural Resources Committee. I have also provided testimony before the Public Utilities Commission of Ohio, the Indiana Utility Regulatory Commission, and the Colorado Public Utilities Commission.

Q **What is the purpose of your testimony?**

A I have been retained by the Office of People's Counsel (OPC) to review the Application of Baltimore Gas and Electric Company ("BGE") for an Electric and Gas MRP. The OPC requested that I evaluate whether BGE's proposed MRP complies with requirements and is designed to achieve the goals as outlined by the Commission's Order Establishing Multi-Year Rate Plan Pilot;[1] as well as whether it

[1] Order Establishing Multi-Year Rate Plan Pilot, February 4, 2020, Public Service Commission of Maryland Case No. 9618, *In Re: Alternative Rate Plans or Methodologies* ("Order").

is consistent with good regulatory policy, including the design of MRPs, rate escalation practices, utility incentives, and processes for forecasts and projections.

Q What materials did you rely on to develop your testimony?

A The sources for my testimony are public documents, industry literature, responses to discovery requests, and concurrently filed Direct Testimony from other expert witnesses retained by the Office of People's Counsel, as well as my personal knowledge and experience.

Q Did you prepare or direct the preparation of this testimony?

A Yes.

Q Please provide an overview of your testimony.

A My testimony begins with a big picture discussion of BGE's MRP Application against the backdrop of the current environment and the Company's recent history. I then address various aspects of the Company's case that are, in my view, inconsistent with either the Commission's Pilot Order or with established regulatory principles. I make various recommendations to the Commission for modifying or changing the Company's proposal accordingly. I then discuss the importance of and propose a framework for the Commission to use in assessing BGE's pilot case for purposes of maximizing the learnings from this pilot.

II. LARGER PERSPECTIVE

Q Do you have any overarching observations about BGE's MRP?

A Yes. Stepping back from the individual provisions of BGE's MRP, three observations stand out about the larger significance of this proposal. The first is that, pursuant to the Order and as proposed within BGE's MRP, Maryland will be the only jurisdiction which implements a broad-based tracker or reconciliation of all expenses to actual costs inside of an MRP. As such, additional ratepayer protections will be necessary. The second is that BGE's MRP continues an unrelenting pattern of increases in its annual revenue requirement, which the reconciliations authorized in the Pilot Order and as proposed within BGE's MRP could further exacerbate. My final observation regarding BGE's MRP is that, if adopted, it will introduce a significant risk of customer of rate shock at its conclusion.

Maryland Would Be the Only Jurisdiction Adopting an MRP that Reconciles All Expenses to Actual Costs

Q Please explain your statement that Maryland will be the only jurisdiction which implements a broad-based tracker or reconciliation of all expenses to actual costs inside of a multi-year rate plan.

A Under the Order, the Commission provided for two reconciliations, the consolidated reconciliation of rate years 1 and 2 (which will occur during rate year 3 of this case, as a part of the Company's next base rate case), and a "final reconciliation" of rate year 3, which will occur following the conclusion of this case. In these reconciliations, any over- or under-collections (comparing actual spending to the amounts recovered in rates) will be credited or returned to customers. BGE's MRP proposes to implement a reconciliation process consistent with that Order. To my knowledge, no Commission has ever adopted an MRP with a broad-based tracker or reconciliation of all expenses to actual costs.[2]

[2] During the PC51 proceeding, the Joint Utilities provided comments that included a report from the Brattle Group that documents this fact. Joint Initial Comments of Baltimore Gas and Electric Company, Potomac Electric Power Company, and Delmarva Power & Light Company, Before the Public

Q What is the significance of the fact the Maryland will be the only jurisdiction to implement a broad-based tracker or reconciliation of all expenses to actual costs inside of a multi-year rate plan?

A The significance of a broad-based reconciliation of all expenses to actual costs is that, as the Maryland Commission found in its Order Establishing Multi-Year Rate Plan Pilot, reconciliations:

> have a tendency to shift financial risks toward customers and reduce incentives for utilities to control costs.[3]

Because I share the Commission's view of the risk shifting nature of reconciliations, my view is that the Commission should impose additional cost control measures to mitigate the risk shifting that could result from the reconciliation processes that the Commission authorized the pilot utility to pursue.

Unrelenting Increases in Revenue Requirements

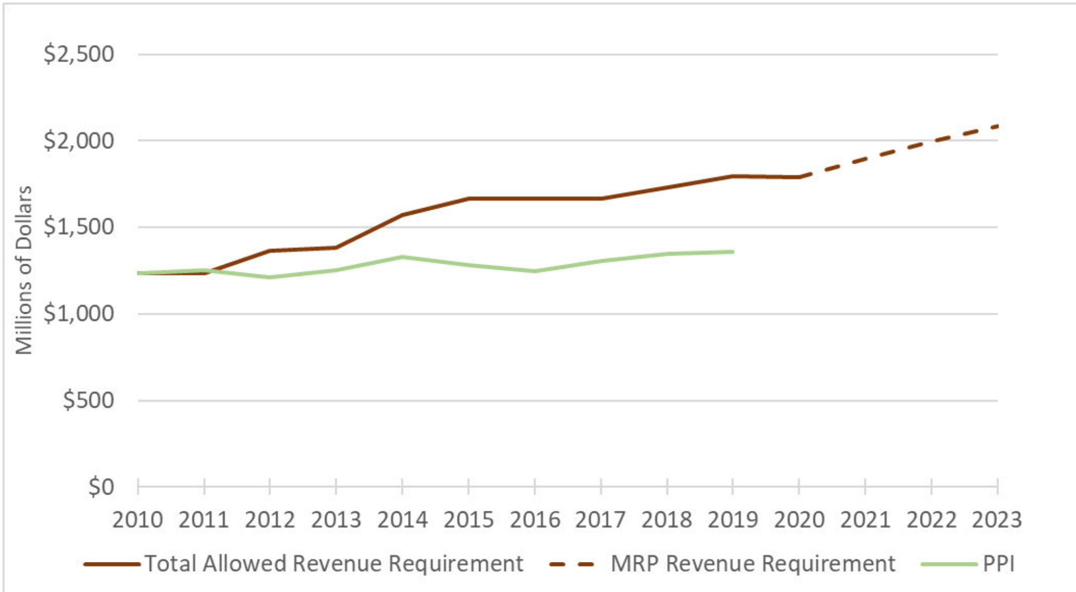
Q Please explain your statement that BGE's MRP continues an unrelenting pattern of increases in its annual revenue requirement that the reconciliations under the Pilot Order could exacerbate.

A It is my observation from evaluating the Commission-established revenue requirements granted to BGE from 2010 through 2019 that BGE has experienced revenue requirement growth at a rate that materially exceeds inflation experienced by utilities during that same period. If projected spending levels in BGE's MRP are approved, that pattern appears likely to continue. **Figure 1** illustrates this trend with historical revenue requirements and the Company's requested increases for the MRP years 2021-2023 (dashed).

Service Commission of Maryland PC1, *In Re: Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates For and Electric or Gas Company*, Appendix A Zarakas, William, Sanem Sergici, Pearl Donohoo-Vallett, Nicole Irwin, March 29, 2018, *Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates*, Response to PC1 Request for Comments, prepared for Joint Utilities of Maryland, pp. 17-20.

[3]Order, p. 26, paragraph 51.

Figure 1. Total historical and requested gas and electric revenue requirements and Producer Price Index (PPI) for the utilities sector[4]



Q **How does the proposed BGE MRP exacerbate this pattern?**

A As I discuss below, BGE employs forecasting methods that escalate the revenue requirement in a manner inconsistent with the Commission's Order and with good regulatory practice. BGE's forecasting practices create budgets far in excess of inflation to start. Because these forecasts would then be reconciled to actual expenses, the forecasts become spending targets for the utility. If BGE underspends the forecast, it must return the revenue already collected. If it overspends, it can

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[4] Figure 1 presents combined gas and electric revenue requirements for the historical period 2010-2019. Combined gas and electric revenue requirements for the year 2020 are according to the Prepared Direct Testimony of David M. Vahos – Part II submitted on behalf of Baltimore Gas and Electric Company, Exhibits DMV-3E-Updated and DMV-3G-Updated. Revenue requirements for the years 2021-2023 are constructed from the Prepared Direct Testimony of David M. Vahos – Part II submitted on behalf of Baltimore Gas and Electric Company, Exhibits DMV-3E-Updated and DMV-3G-Updated, with the total benefits and adjustments to both the electric and gas revenue requirements presented on page 71 of the Direct Testimony of David M. Vahos added back in to the revenue requirements presented in Exhibits DMV-3E-Updated and DMV-3G-Updated to reflect the true burden that will imposed on ratepayers. The PPI series is based upon the PPI index for utilities, and reflects the combined gas and electric revenue requirements for 2010 escalated at this PPI series' rate of increase. PPI data from Federal Reserve Bank of St. Louis and available online at https://fred.stlouisfed.org.

seek additional revenue. Neither the forecasting method nor the reconciliation process provide cost-containment incentives to BGE. Furthermore, BGE will be under pressure from investors to increase its earnings by increasing the rate base to which the ROE applies. For this reason, it is of paramount importance that the Commission carefully scrutinize the spending budgets that BGE has presented in this case.

Potential for Post-MRP Rate Shock

Q Please explain your statement that the BGE MRP will introduce a significant risk of customer of rate shock at its conclusion.

A By Company witness Vahos' calculation, BGE's MRP essentially borrows $461.7 million from the future, leaving customers incrementally responsible for that amount at the MRP's conclusion.[5] This figure does not account for additional carrying costs, for the potential of any major storm damage,[6] or for the potential that BGE's forecasts are lower than its actual expenditures such that customers will pay even more during reconciliation. While the economic impacts from the COVID-19 health emergency do justify consideration of using deferrals to mitigate rate impacts in the near term, nothing in BGE's MRP suggest that BGE is seeking opportunities to do as much as possible with as little as possible.[7] The most responsible course for a regulated utility to pursue in this trying economic situation would be to optimize its effectiveness while minimizing its costs. As illustrated by the graph above, BGE's proposed MRP is in no manner successful in reigning in costs.

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[5] Direct Testimony of David Effron, submitted on behalf of the Office of People's Counsel, August 14, 2020, p. 5.

[6] Direct Testimony of David Effron, submitted on behalf of the Office of People's Counsel, August 14, 2020, p. 4.

[7] In fact, quite the opposite. As detailed by OPC Witnesses Alvarez and Stephens, BGE's electricity capital budgets demonstrate that BGE is likely approaching or beyond the point of diminishing returns for reliability-related grid investments, achieving little benefit despite substantial investment. See Panel Response Testimony of Paul J. Alvarez and Dennis Stephens EE, on behalf of the Maryland Office of People's Counsel, August 14, 2020, p.16.

III. MRP MODIFICATIONS

Detail Benefits that Consumers Should Expect

Q What has the Commission said about the benefits consumers should expect to receive from an MRP?

A The Commission found that the benefits of the MRP for consumers would be more predictable rates and that changes in rates would be spread over multiple years.[8]

Q Has the Commission provided direction to the pilot MRP utility regarding customer benefits?

A Yes. The Commission ordered that the pilot utility should, at a minimum, provide in a clear and concise manner "detailed benefits that consumers should expect as a result of the Pilot Utility's participation and filing of [an] MRP."[9]

Q Does BGE's proposed MRP provide such an enumeration of the detailed benefits that consumers should expect as a result of BGE's participation in an MRP?

A No. BGE's proposed MRP does not provide in a clear and concise manner the detailed benefits that consumers should expect as a result of BGE's participation in an MRP. The application itself is devoid of any identification of consumer benefits that result from BGE's participation in an MRP.

Q Has BGE provided, outside of its proposed MRP, an enumeration of the benefits consumers should expect from the MRP?

A No. BGE has not supplemented its MRP to enumerate the benefits consumers should expect from the MRP. When OPC inquired what benefits consumers should expect as a result of the MRP, BGE responded by quoting the Commission's order.[10] Additionally, BGE directed OPC to specific portions of the Direct Testimony of Mark D. Case,[11] which similarly referenced the Commission's

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[8] Order, p. 1.

[9] Order, p. 18, paragraph 25.

[10] BGE Response to OPC DR 13-02.

[11] BGE Response to OPC DR 13-02.

Order[12] or described BGE efforts underway that would have occurred with or without participation in an MRP, such as EmPOWER Maryland programs, the STRIDE program, BGE's status as an ISO 14001 certified organization, the EV charging program,[13] and the impacts the ongoing BGE capital investments and the SEED Program have on economic development.[14]

Q Does BGE's MRP comply with the Commission's directive to provide in a clear and concise manner "detailed benefits that consumers should expect as a result of the Pilot Utility's participation and filing of [an] MRP."

A No. BGE's MRP does not comply with the Commission's directive to provide in a clear and concise manner "detailed benefits that consumers should expect as a result of the Pilot Utility's participation and filing of [an] MRP." When the Commission directed the applicant of an MRP to provide, clearly and concisely, detailed benefits that consumers could expect *as a result of* the utility opting for an MRP instead of a traditional rate case, it had already noted the benefits of more predictable rates and that changes in rates would be spread over multiple years. It is unlikely that the Commission expected an MRP applicant to quote its Order to meet the requirement.

Q Do you have a recommendation regarding BGE's failure to comply with the Commission's directive to provide detailed benefits that a consumer should expect to receive as a result of BGE's participation in an MRP?

A Yes. I recommend that the Commission find that BGE failed to comply with the Commission's directive to provide detailed benefits that a consumer should expect to receive as a result of BGE's participation in an MRP. Should the Commission nonetheless approve BGE's MRP, the Commission should identify in a clear and concise manner the benefits that it expects BGE to deliver to consumers as a direct

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[12] Prepared Direct Testimony of Mark D. Case, submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, pp. 17-18.

[13] Prepared Direct Testimony of Mark D. Case, submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, pp. 24-25.

[14] Prepared Direct Testimony of Mark D. Case, submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, pp. 29-30.

result of the Commission's approval of the MRP—benefits that would not otherwise be available to them if BGE had pursued a traditional rate case.

Enhance Reporting Requirements

Q Did the Working Group or Staff provide an opinion regarding the need for ongoing reporting during the operation of the MRP?

A Yes. The Working Group came to the consensus that a utility should file a mid-year report addressing completions and significant changes to capital projects as an early warning in advance of annual filing requirements.[15] Staff also recommended amending COMAR 20.07.04.07(A) to include a requirement that:

> A public service company filing an application in support of a multi-year rate plan ("MRP") shall also comply with any additional filing requirements and **continuing reporting requirements** authorized by the Commission.[16] (Emphasis added.)

Q What has the Commission said about reporting requirements within the MRP?

A The Commission directed that the pilot MRP must track the accuracy of the utility's forecast, have an annual informational filing, and also contain adequate reporting requirements.[17] The annual informational filing must compare forecasted data to actuals.[18] The Commission provided a template showing minimum levels of information with associated back-up materials that it would require.[19] The Commission, however, did not offer further guidance regarding what it viewed to be "adequate reporting requirements."

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[15] Order, p. 34, paragraph 70.

[16] Implementation Report, December 20, 2019, Public Service Commission of Maryland Case No. 9618, *In Re: Alternative Rate Plans or Methodologies* ("Report"), p. 64, Section II.I. Item 9.

[17] Order p. 3, paragraph 4.

[18] Order pp. 4 & 37, paragraphs 5 & 79.

[19] Order, Appendix 1.

Q What has BGE suggested regarding reporting within its proposed MRP?

A I could not find a proposal that addresses the Commission's MRP condition for "adequate reporting requirements" within BGE's MRP application.

Q What is the significance of BGE's failure to address the MRP condition for "adequate reporting requirements" within its MRP application?

A The Commission has established minimum MRP filing requirements that a pilot utility pursing an MRP must meet. These include that the utility-proposed MRP contains adequate reporting requirements.[20] This requirement is separate and distinct from the annual information filing that the Commission also required.[21] BGE has proposed no reporting requirements whatsoever, so the plan on its face fails to meet the Commission's minimum filing requirements. This failure will make it difficult to perform a post-implementation assessment of the pilot MRP as well as to monitor BGE's performance during the MRP.

Q Do you have a recommendation regarding BGE's failure to propose a framework to address adequate reporting requirements?

A Yes. I recommend that the Commission find that BGE failed to address adequate reporting requirements. Should the Commission nonetheless approve BGE's MRP, it should impose adequate reporting requirements. In my view, this would include, at a minimum, the metrics that I identify below in my testimony regarding a framework for evaluating the pilot MRP effort. Additionally, these metrics will support the ongoing performance incentive mechanism process.

[20] Order, p. 3, paragraph 4.

[21] *Ibid*.

Amend Off-Ramp Process

Q Did the Working Group or Staff provide an opinion regarding the need for an off-ramp process?

A The general consensus of the Working Group was that the Commission should allow for an approved MRP to be reviewed upon a petition by the utility or a stakeholder based on a major change.[22]

Q What has the Commission said about an off-ramp process in the MRP?

A The Commission directed that an MRP contain specific criteria for any off-ramp process which it defined to include extraordinary circumstances outside of the utility's control that would warrant the Commission's intervention to modify or terminate the MRP.[23] The Commission further defined such extraordinary circumstances as those that "call into question whether the existing rates are just and reasonable or threaten the fiscal solvency of the utility."[24] The Commission further expressed that the combination of an annual informational filing and the off-ramp would provide opportunities to address the impact of any extraordinary events on utility operations.[25] However, the utility would not be restricted to petitioning for relief under an off-ramp provision to the annual filing period, but could file for relief at any time.[26]

Q What has BGE suggested regarding an off-ramp within its proposed MRP?

A BGE has proposed that the Commission approve an off-ramp "through which any party, including the Commission on its own motion, may file a petition to re-open and review the Company's [MRP] if there is sufficient evidence that there is an issue that cannot be resolved through another avenue available under the [MRP]."[27]

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[22] Order, pp. 29-30, paragraph 58.

[23] Order, p. 3, paragraph 4.

[24] Order, p. 30, paragraph 60.

[25] Order, pp. 26-27, paragraph 51.

[26] Order, p. 38, FN 103.

[27] Prepared Direct Testimony of Mark D. Case, submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, p. 23, lines 2-4.

BGE proposes the provision would cover extraordinary circumstances outside of the control of the utility that occur during the MRP period, which may include changes in law, natural disasters, cyber or terror attacks, major economic events or other circumstances that would warrant the Commission's intervention to modify or terminate the MRP.[28] BGE proposes that the petitioning party should include a recommended proposal, timeline, and procedural schedule as part of its petition.[29]

Q Does BGE's proposed off-ramp provision meet the requirements for an off-ramp provision described by the Commission?

A No. BGE's proposed off-ramp provision does not meet the requirements described by the Commission. While BGE generally adopts the Commission's language regarding extraordinary circumstances outside the utility's control that warrant Commission intervention to modify or terminate the MRP, it does not include the threshold materiality requirement that the impact of the extraordinary circumstance must be such that it "calls into question whether the existing rates are just and reasonable or threaten the fiscal solvency of the utility."

Q Do you have a recommendation regarding BGE's failure to address the materiality of extraordinary circumstances required to trigger the off-ramp?

A Yes. I recommend that the Commission find that the off-ramp proposed by BGE is inadequate; and that it modify BGE's MRP off-ramp proposal to provide that the off-ramp is only available for extraordinary circumstances outside of the control of the utility that have the potential to cause substantial harm to BGE's ability to serve customers, threaten its fiscal solvency, or results in rates that are unjust or unreasonable.

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[28] Prepared Direct Testimony of Mark D. Case, submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, p. 23, lines 5-9.

[29] Prepared Direct Testimony of Mark D. Case, submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, p. 23, lines 11-13.

Revise Forecasts

Q What is the significance of the forecasting method within an MRP pursuant to the Commission's Order?

A The forecasting method is used to escalate the MRP's annual revenue requirement.

Q Did the Working Group or Staff provide an opinion regarding how forecasts were to be generated for use within the MRP?

A The Working Group considered whether there should be a standardized method of forecasting for both discrete and stochastic forecasts. It defined a discrete forecast as a forecast of something under the control of the utility, such as capital expenditures. It defined a stochastic forecast as a forecast of something not under the control of the utility, such as future sales. It determined that there was no need to standardize forecasting methods among utilities but that a utility must be consistent with the forecasting method relied upon within an MRP.[30]

Q What has the Commission said about the generation of forecasts for use within the MRP?

A The Commission agreed with the Working Group that forecasts should begin with a 12-month historical test year. The Commission, however, determined it would not require the pilot utility to use a particular method of forecasting but that the utility should be consistent in its forecasting method throughout its MRP filing.[31] The Commission stated that "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."[32]

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[30] Report, p. 42, Section II.E.(iv).

[31] Order, p. 21, paragraphs 41-42.

[32] Order, pp. 21-22, paragraph 43.

Q How is revenue escalation typically determined for an MRP?

A MRPs escalate revenue annually using external indices, a utility's forecasted revenue needs, or a hybrid in which O&M revenues are determined by external indices and capital costs are based upon the utility's forecasted needs.[33]

Q How would a utility apply the external indices method in an MRP?

A When utilities use external indices within an MRP, the indices are often based on inflation rates and productivity factors. In some cases, different categories of costs are escalated at different rates based on separate cost indices. For example, Southern California Edison ("SCE") uses a variety of indices to forecast O&M and capital cost escalation, including the Handy-Whitman Index of Public Utility Construction Costs, IHS Global Insight Forecasts, and internal labor indexes.[34] A common approach found in other jurisdictions is to escalate expenditures using a general measure of output inflation for the national economy, such as the gross domestic product price index ("GDP-PI") less a productivity factor ("X-Factor"). In other words, "GDP-PI – X-Factor" is often used as the external index. The X-Factor is typically included in an MRP index-based formula to reflect the fact that the formula should account for productivity trends of the target utility and the electricity industry in general. The X-Factor is often subtracted from an index-based growth trend (such as inflation) to provide the target utility with an incentive to increase productivity relative to that trend. To properly calibrate the X-Factor, a productivity factor study would need to be conducted. Productivity factor studies typically require identifying a peer group with which to compare the target utility, assessing the historical productivity trends of that peer group over many years, and comparing those trends with the historical trends of the target utility.

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[33] Lowry, MN, J Deason, M Makos, L Schwartz. 2017. *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,* U.S. Department of Energy Grid Modernization Laboratory Consortium, Section 4.1 https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf

[34] Southern California Edison (U 338-E) 2018 General Rate Case Application 16-09-001 (SCE-09, Vol. 1) at 86.

Q **What jurisdictions have used this index-type approach?**

A In addition to SCE, escalation based upon external indices is used in at least Massachusetts (National Grid), Maine (Central Maine Power), Washington (Puget Sound Energy), and in the Canadian Provinces of Ontario and Alberta.[35]

Q **How does the utility cost forecast method work?**

A As described in *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, this type of escalation is based solely on forecasted increases in revenue based upon a predetermined percentage each year, much like a rate case with multiple test years.[36]

Q **What jurisdictions have adopted the utility cost forecast method?**

A New York rate plans have adopted the utility cost forecast method.[37]

Q **What forecasting method has BGE adopted within its proposed MRP?**

A BGE has adopted none of the three recognized forecasting methods used in MRPs: not the index method, the utility cost forecast method, or the hybrid method. Instead BGE has described its forecasting method as a product of its prediction of its future needs based upon company-specific work plans, the development of budgets for capital investment and O&M expenses at a project level based upon historical

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[35] See for example Order, September 30, 2019, Massachusetts DPU Docket No. DPU 18-150, *In re: Petition of Massachusetts Electric Company and Nantucket Electric Company dba National Grid* https://fileservice.eea.comacloud net/FileService.Api/file/FileRoom/11262053; Order Approving Stipulation, July 1, 2008, Maine Public Utilities Commission Docket No. 2007-00215, *In Re: Central Maine Power* https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=66869&CaseNumber=2007-00215

[36] Lowry, MN, J Deason, M Makos, L Schwartz. 2017. *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, U.S. Department of Energy Grid Modernization Laboratory Consortium, Section 4.1 https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf

[37] Lowry, MN, J Deason, M Makos, L Schwartz. 2017. *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,* U.S. Department of Energy Grid Modernization Laboratory Consortium, Section 6.16. https://eta.lbl.gov/sites/default/files/publications/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf; Lowry, Mark Newton and Tim Woolf. 2016. *Performance-Based Regulation in a High Distributed Energy Resources Future,* Lawrence Berkeley National Laboratory, p. 27. https://emp.lbl.gov/sites/all/files/lbnl-1004130_0.pdf.

trends in spending,[38] and escalation of those budgets by an inflation factor.[39] While that sounds reasonable on its face, a close examination reveals that the Company's approach to spending forecasting in this MRP lacks consistency and is inconsistent with sound regulatory practice.

In multiple instances, the budgets upon which BGE builds its spending forecast contain placeholders—in other words, dollars for projects that are not defined and do not exist.[40] The budgets also contain projects which BGE now knows will not be built.[41] As for BGE basing its budgets upon historical spends with escalation for inflation, a review of BGE's budgets include multiple instances in which historical budgets were doubled or tripled or more without explanation and an irregular application of inflation.[42]

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[38] Prepared Direct Testimony of David M. Vahos – Part II submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, pp. 16-29.

[39] See Prepared Direct Testimony of A. Christopher Burton submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, p. 31, line 1 and Company Exhibit ACB-1, pp. 3 of 17, 14 of 17; See also Prepared Direct Testimony of Robert D. Biagiotti, P.E. on behalf of Baltimore Gas and Electric Company, May 15, 2020, p. 20, lines 8 and 20, p. 22, line 8, p. 24, line 2, p. 26, lines 7 and 21, Company Exhibit RDB-1, pp. 2 of 35, 4 of 35, 5 of 35, 24 of 35, 25 of 35.

[40] See Direct Testimony of Brendan Larkin-Connolly, submitted on behalf of the Office of People's Counsel, August 14, 2020, p. 54, describing placeholders for building security at company office buildings and pp. 46-47, 48, describing placeholders for information technology.

[41] BGE Response to StaffDR 74-01(b), August 7, 2020.

[42] See Direct Testimony of David Effron, submitted on behalf of the Office of People's Counsel, August 14, 2020, pp. 12-15 for an inexplicable escalation of minor storm damage line item and p. 15 for a description of the imprecise application of a 2.5% inflation adjustment to non-labor O&M; See Direct Testimony of Brendan Larkin-Connolly, submitted on behalf of the Office of People's Counsel, August 14, 2020, pp. 42-43 describing gas tools budget more than doubling without explanation, pp. 50-51 describing fleet budget more than doubling without explanation, pp. 59-60 describing innovation pilots doubled without explanation, pp. 60-61 describing "other capital" more than doubling without explanation, pp. 52-53 describing tripling the budget for facilities to include HVAC, elevators, alarms, motors, chillers, boilers and paving without explanation, and pp. 53-54 describing an astonishing 200x historical budget for capital lifecycle projects, again, without explanation; See Panel Response Testimony of Paul J. Alvarez and Dennis Stephens EE, on behalf of the Maryland Office of People's Counsel, August 14, 2020, pp. 14-16, describing dramatic growth in electricity reliability investments for little to no reliability gain, pp. 17-22, describing replacement of functioning 4kV lines when costs do not exceed benefits, pp. 22-25, describing capital additions for substation security that are not supported by industry practice, pp. 25-29, describing the "proactive" replacement of functioning transformers, pp. 31-32, describing a cable replacement program in which the costs do not exceed the benefits, pp. 36-43, describing a tripling of the historic electricity capacity expansion budget without adequate data-driven

Q Does BGE's proposed budget meet the requirements for forecasting described by the Commission?

A No. BGE's proposed budget does not apply any recognized forecasting method. Nor does it propose a cohesive forecasting approach. With respect to numerous spend categories, BGE inexplicably and unpredictably escalates its budgetary forecasts based upon no discernable workplan or indices, and in a manner that is not transparent.

Q Does BGE's proposed budget comport with good regulatory practice?

A No. BGE does not properly apply any of the three recognized revenue escalation methods. It did not establish a predetermined percentage increase for each year that it then applied to escalate the historical test year. Instead, BGE modified individual budgets at will based upon company-specific work plans or no work plan at all. Nor did it apply the external index approach in any recognizable way. It applied the inflation factor to modified budgets, and not the historical test year. The Company also failed to justify or explain the variable inflation factor it applied when it routinely escalated its modified budgets. BGE case also fails to apply the hybrid method, which applies the external index approach to O&M and the utility cost forecast to capital budgets. BGE applied both an external index (inflation factor) and its own version of a utility cost forecast for all expenses—using two methods to escalate the same expenses.

Q What would be the result of adopting BGE's MRP forecasting method?

A If BGE's MRP were adopted using its proposed forecasting method, costs within the MRP would be unnecessarily and arbitrarily escalated with no discernable cost-containment. Additionally, the asymmetric understanding of BGE's internal company specific budgets and work plans would undermine transparency and ultimately prudency reviews.

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explanation and despite falling system demand, pp. 50-52, describing a 36.5% increase in electric new business capital over historic spending despite the economic downturn, p. 54.

Q Do you have a recommendation regarding BGE's forecasting method?

A Yes. I believe that the Company's failure to comply with the Commission's directive that utility forecasting be consistent is grounds for denial of the Company's Application. In the event that the Commission approves BGE's MRP, I recommend that the Commission adopt the budgetary and spending recommendations of OPC Witnesses Effron, Larkin-Connolly, and Alvarez and Stephens. Those recommendations will greatly mitigate the impacts surrounding the Company's approach to forecasting.

Eliminate ROE Performance Adder

Q What has BGE suggested regarding an ROE Performance Adder?

A BGE originally proposed that its return on equity should be adjusted upwards for a performance adder of 35 basis points because "when a utility shows consistent excellent performance and customer satisfaction, that historical performance should positively impact the return on equity authorized by the Commission."[43] However, it has modified that request to 20 basis points, in light of the COVID-19 pandemic impact on the Company's customers.[44]

Q What support does BGE offer to establish its "consistent excellent performance"?

A BGE Witness David M. Vahos testified that, with regard to electricity customers, "Since 2014, BGE has delivered first quartile 2.5 Beta CAIDI results and in 2019 BGE delivered first quartile 2.5 Beta SAIFI results as well."[45] With regard to gas customers, Mr. Vahos testified that BGE "has consistently delivered first decile gas

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[43] Prepared Direct Testimony of David M. Vahos – Part I submitted on behalf of Baltimore Gas and Electric Company, March 2, 2020, p. 2.

[44] Prepared Direct Testimony of David M. Vahos – Part II submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, p. 6, lines 17-19.

[45] Prepared Direct Testimony of David M. Vahos – Part II submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, p. 4, lines 9-11. CAIDI refers to Customer Average Interruption Duration Index and SAIFI refers to System Average Interruption Frequency Index.

emergency response times, responding to 99.97 [percent] of emergencies within less than an hour."[46]

Q What support does BGE offer to establish its customer satisfaction?

A BGE witness Mark D. Case testified that more than 90 percent of residential customers are satisfied with their service based upon a research study conducted by a market research firm via phone call with a random sample of customers across the BGE service territory.[47] Mr. Case also testified that BGE's service to business electric and gas customers resulted in J.D. Power's "Highest" award among Large Utilities in the East.[48]

Q Is it a customary regulatory practice for a commission to increase an authorized return on equity based upon a utility's historical performance?

A No. I am not aware of a circumstance in which a Commission increased an authorized return on equity for historical performance. Nor does BGE cite any precedent for an enhancement of an authorized return on equity for historical performance, in Maryland or elsewhere. In fact, BGE has acknowledged that "[a] utility's performance – good or bad – is not an input used in any of the models commonly used for determining the appropriate return on equity."[49] It is, however, a regulatory practice for a commission to express its displeasure with historical utility performance by reducing an authorized return on equity during the following rate case. For instance, the Hawaii Public Utilities Commission explicitly reduced authorized return on equity for poor historical performance by MECO despite the

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[46] Prepared Direct Testimony of David M. Vahos – Part II submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, p. 4, lines 11-14.

[47] Prepared Direct Testimony of Mark D. Case, submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, pp. 14, lines 15-16 and p. 31, line 13; BGE Response to Staff Data Request 19, Item No. StaffDR19-16.

[48] Prepared Direct Testimony of Mark D. Case, submitted on behalf of Baltimore Gas and Electric Company, May 15, 2020, p. 31, line 14-19.

[49] BGE Response to OPC Data Request 28-01(e), August 7, 2020.

fact that the parties to the case had stipulated the higher return on equity.[50] The Hawaii Public Utilities Commission slashed the agreed upon return on equity by 50 basis points, stating that:

> The commission finds it appropriate to adjust the Parties' stipulated ROE another 50 basis points downward in light of apparent system inefficiencies which negatively impact MECO's customers. For example, MECO appears unable to properly address known renewable energy curtailment issues. … Additionally, among other matters, MECO appears unable to control operational costs such as pension costs which are discussed above.[51]

This Commission has also found, in a Pepco rate case, that:

> Pepco's ROE should reflect the substandard reliability and service quality of Pepco's distribution system, as our recent decision in Case No. 9240 emphasizes. The Company must be held accountable, and cannot provide poor service and expect that its return on equity and overall rate of return will be unaffected, let alone increased.[52]

Q Do you recommend that BGE be awarded an ROE Performance Adder in its MRP?

A No. There is no regulatory basis to enhance BGE's authorized ROE based upon historical performance. Additionally, the evidentiary support of excellent performance is thin. While BGE has highlighted a handful of meritorious performance indicators, these do not on their own provide sufficient insight into BGE's performance relative to Maryland's regulatory goals and Maryland's expected level of performance from BGE. As discussed above, BGE's performance has resulted in an uninterrupted pattern of increasing costs to customers. Failure to control costs was one of the reasons the Hawaii Public Utilities Commission cited

[50] Decision and Order No. 31288, May 31, 2013, Hawaii Public Utilities Commission Docket No. 2011-0092, *In Re: Application of Maui Electric Company*, p. 107-110 https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A13F03B43854C12062.

[51] *Ibid*.

[52] Order No. 85028, July 20, 2012, Maryland Public Service Commission Case No. 9286, *In Re: Application of Potomac Electric Power Company for Authority to Increase its Rates and Charges for Electric Distribution Service*, p. 108.

in reducing MECO's ROE. BGE's increasing costs do not support an enhanced ROE. I recommend eliminating BGE's proposed ROE Performance Adder.

BGE will have an opportunity in its next rate case to incorporate comprehensive performance metrics, target, and incentives based upon the ongoing effort within Case No. 9618, Phase II. As I discuss below, BGE can facilitate the adoption of incentives in the next rate case (whether MRP or traditional) by beginning to track and share key metrics in this case. By incorporating performance rewards at the conclusion of this comprehensive process, the Commission will be able to articulate its expectations of BGE's performance and to align incentives with those expectations and policy goals so that BGE will be rewarded for the performance the Commission finds desirable.

IV. EVALUATION OF PILOT MRP EFFORT

Basis for Evaluation of Pilot MRP

Q Did the Working Group or Staff provide an opinion regarding the importance of reviewing the operation of the initial pilot MRP?

A Yes. The Working Group reached consensus that a "lessons learned" review following the initial MRP test case was necessary. Staff proposed that this review occur at the conclusion of the initial MRP to discuss changes or modification to the MRP process going forward. Staff proposed that these would be informal sessions followed by a Staff-prepared report detailing recommendations.[53]

Q Did the Commission adopt a requirement for a post-implementation review of the initial MRP?

A Yes. The Commission found a post-implementation review would be helpful to inform future MRP filings. The Commission directed Staff to prepare and file a

[53] Order, p. 12, paragraph 22.

report detailing recommendations to improve MRP filings and the review process in Case No. 9618.[54]

Q Did the Commission identify the requirements or a framework for a post-implementation lessons learned evaluation of the initial MRP?

A No. The Commission did not identify requirements or a framework for a post-implementation lessons learned evaluation of the initial MRP.

Q Did BGE propose a framework for post-implementation evaluation of its MRP?

A No.

Evaluation Criteria

Q What were the Commission's stated goals in pursuing multi-year rate plans as an alternative to cost of service regulation?

A As the Commission described in Order No. 89226,[55] the Commission is mandated to ensure continued just and reasonable rates. It has accomplished this using cost of service regulation, employing the following principles.

> The Commission's principles of ratemaking balances utility cost recovery, rate impact, consumer interests and public policies.[56]

The Commission identified perceived drawbacks in traditional ratemaking relating to "a failure to equitably distribute risk, limited capabilities to monitor costs, limited ability to achieve policy outcomes and potential restrictions on utility innovation, and arguably regulatory lag, which can impede the utilities' ability to earn their authorized ROR."[57] The Commission found that alternative forms of regulation "may be helpful, if carefully implemented, in facilitating the achievement of the

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[54] Order, p. 13, paragraph 25.

[55] Order on Alternative Forms of Rate Regulation and Establishing Working Group Processes, August 9, 2019, Public Service Commission of Maryland PC51 Case No. 9618, *In Re: Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*

[56] *Id*. at p. 52.

[57] *Ibid*.

State's ambitious goals regarding electrification, renewable development, pipeline replacement, development of new consumer solutions, grid resiliency, and other state goals."[58] The Commission opted to pursue MRPs over other alternative forms of regulation because it anticipated MRPs would deliver the following benefits:[59]

- Shortened cost recovery periods
- More predictable revenues for utilities
- More predictable rates for customers
- Changes in rates spread over multiple years
- Decreased administrative burden on regulators by staggering filings over several years
- More transparency into the utility planning process

Additionally, the Commission found "MRPs also allow adjustments to reflect changes in the business environment, rather than changes in the utility's actual revenue and costs."[60]

Q How would you synthesize, into evaluation criteria, the Commission's mandated obligation to ensure just and reasonable rates, its principles of ratemaking, and its goals for implementing alternative ratemaking, particularly an MRP?

A I would rely upon the Commission's principles for ratemaking to serve as a functional organizing structure: utility cost recovery, rate impact, consumer interests, and public policies. I will address each component of this structure below.

[58] *Id*. at pp. 52-53.

[59] Order, p. 1.

[60] Order on Alternative Forms of Rate Regulation and Establishing Working Group Processes, August 9, 2019, Public Service Commission of Maryland PC51 Case No. 9618, *In Re: Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*, p. 54.

Utility Cost Recovery

Q How could a post-implementation evaluation assess the impact of the pilot MRP on utility cost recovery?

A The Commission identified the likelihood that an MRP would shorten the cost recovery period and provide more predictable revenue for utilities as a benefit of MRPs. The combined impact of these features should be reflected in the ability of the utility to earn its authorized return on equity. While a causal link could not necessarily be assumed, the ability of a utility to earn its return on equity under an MRP would be an instructive metric.

Rate Impact

Q How could a post-implementation evaluation assess the impact of the pilot MRP on utility rates?

A Since rate impacts are causally related to the escalation of the annual revenue requirement and the net annual reconciliations, rate impacts could be assessed through several lenses. One is simply the percentage increase or decrease of the combined annual revenue requirement and the net annual reconciliation adjustments year over year. A variation on this metric would be to compare the result to annual revenue requirement changes of peer utilities. A second method is to test the forecasting method for revenue escalation proposed as part of the first MRP against an escalation based upon external indices.

Q How could the results of the pilot MRP forecasting revenue escalation method be compared to an escalation based upon external indices?

A As part of this MRP proceeding, the Commission could adopt and implement BGE’s forecasting revenue escalation method. At the same time, the Commission could adopt, but not implement, a “shadow” escalation method based upon external indices. By adopting both methods but implementing BGE’s forecasting revenue escalation method, the Commission and stakeholders will be able to compare how the selection of one method over the other impacted the overall revenue requirement.

Q How would the Commission adopt, but not implement, a revenue escalation method using external indices?

A The Commission could adopt a revenue escalation method using external indices by selecting, within this case, the inputs required to establish a revenue calculation using exogenous factors. The Commission could then direct BGE to calculate and track the revenue requirement using both methods and report the results annually. For purposes of selecting external indices, the Commission could rely upon GDP-PI and it could assume that the productivity factor is 0, meaning that no productivity is assumed. This method is consistent with that adopted by jurisdictions implementing revenue escalation methods using exogenous, external indices. It is also well-aligned with the Commission's stated expectation that an MRP will allow adjustments from the historical test year to reflect changes in the business environment, rather than changes in the utility's actual revenue and costs.

Consumer Interests

Q How could a post-implementation evaluation assess the impact of the pilot MRP on consumer interests?

A Consumer interests begin with ensuring cost-effective, reliable, and safe service. The Commission indicated that consumer interests would benefit from an MRP because rates would be more predictable and changes in rates would be spread over multiple years. Additionally, the Commission anticipated that an MRP would increase transparency. The post-implementation of the pilot MRP should assess each of these elements of consumer interest.

Q How could a post-implementation evaluation assess the impact of the pilot MRP on cost-effectiveness?

A The MRP should ensure the prudency of expenditures and, under BGE's proposed MRP, that consumers receive the benefit of the projects serving as the foundation of the MRP budget. If the forecasted budgets reflect prudent expenditures, then the deviation of actual expenditures from forecasted costs could indicate prudence. However, the information available at this stage of the process makes it difficult to be confident the forecasted budgets do reflect prudent expenditures, so it is necessary to conduct a qualitative assessment as to whether the reconciliation process provided an adequate opportunity to review prudence. Finally, because specific projects form the foundation of BGE's MRP budget, a comparison between which projects were budgeted and which were completed will provide information relevant to whether consumers benefitted from the MRP.

Q How could a post-implementation evaluation assess the impact of the pilot MRP on reliability and safety?

A Electric and gas utilities have well-established metrics for reliability and safety such as CAIDI, SAIFI, dig-in/location faults, response time to gas odor complaints, and OSHA recordable incidents. The MRP could include a process for identifying key reportable metrics related to reliability and safety that could be tracked and assessed for trends to determine whether performance improved, eroded, or remained consistent.

Q How could a post-implementation evaluation assess the impact of the pilot MRP on providing more predictable rates and changes in rates spread over multiple years?

A The two reconciliation processes outlined in the Pilot Order will move rates up or down depending upon how much actual expenditures vary from those budgeted. To the extent this variation is substantial it can create rate volatility. A simple measure of whether the MRP provides predictable rates that mitigate rate volatility is to track actual rates following the reconciliations. Comparing these to rates to those predicted at the initiation of the MRP will provide as indication of predictability.

Q How could a post-implementation evaluation assess the impact of the pilot MRP on transparency into the utility planning process?

A Transparency of utility planning and decision-making is ever more important to meet the challenge of growing distribution system complexity arising from the proliferation of cost-effective new technologies for energy efficiency, generation, storage, and management controlled by customers. By increasing the transparency of grid-related investment decisions, utilities and customers will be able to optimize the use of all available resources to meet customer needs and enhance the likelihood of achieving Maryland's energy and climate goals, while avoiding unnecessary costs and improving grid reliability and resilience. Transparency goes well beyond disclosing individual projects. Indicators of transparency include, among others, ease of access to time and locational values of distributed energy resources, open and shared planning processes to include training in tools such as modeling, and competitive procurement processes for non-wires alternatives. An assessment of transparency could include a qualitative evaluation of the degree to which the utility shares information about and encourages participation in utility planning and decision-making.

Public Policies

Q How could a post-implementation evaluation assess the impact of the pilot MRP on Maryland's public policies?

A The Commission expressed an optimism that a carefully implemented MRP could help to facilitate public policy goals regarding electrification, renewable development, pipeline replacement, development of new consumer solutions, and grid resiliency. To the extent that each of the goals has identified targets, these targets could be tracked to assess how well the MRP is advancing them. If no established metrics exist, BGE could be directed to identify how its MRP will advance each of the public policies and associated metrics to track that effort.

Recommendations for Evaluation of Pilot MRP Effort

Q To summarize, what are your recommendations for a framework for evaluation of BGE's pilot MRP effort?

A My recommendation is that the Commission adopt a framework for the post-implementation review of the pilot MRP effort and direct BGE to track, evaluate, and report on the following metrics to assist the Commission in its post-implementation evaluation of the pilot MRP effort:

- To evaluate the ability of the utility to recover its costs, track the utility's actual return on investment relative to its authorized return on investment.
- To evaluate rate impact:

- Track the percentage increase or decrease of the combined annual revenue requirement and the net annual reconciliation adjustments year over year, and compare the result to annual revenue requirement changes of peer utilities; and
- Calculate an annual revenue requirement using GDP-PI-X to escalate from the historical test year where X is 0 and compare it to the BGE combined annual revenue requirement and the net annual reconciliation adjustments year over year.

- To evaluate consumer interests:
  - Track the deviation of actual expenditures from forecasted costs;
  - Conduct a qualitative assessment as to whether the reconciliation process provided an adequate opportunity to review prudence;
  - Track which projects were budgeted and which were completed;
  - Identify and report on key metrics related to reliability and safety, and assess for trends to determine whether performance improved, eroded, or remained consistent;
  - Track actual rates year over year to assess whether the MRP produced predictable rates and mitigated rate volatility; and
  - Conduct an annual, qualitative evaluation of the degree to which the utility shares information about and encourages participation in utility planning and decision-making—including but not limited to ease of access to time and locational values of distributed energy resources, open and shared planning processes to include training in tools such as modeling, and competitive procurement processes for non-wires alternatives.
- To evaluate public policies:
  - To the extent that Maryland has identified targets for its goals of electrification, renewable development, pipeline replacement,

development of new consumer solutions, and grid resiliency, track progress toward the targets to assess how well the MRP is advancing them; and

- If no established metrics exist, the Commission should direct BGE to identify how its MRP will advance each of the public policies together with associated metrics to track that effort.

Q Does this conclude your testimony?

A Yes, it does.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Principal*, 2019–present.

Provides expert consulting services for removing operational, regulatory, and policy barriers to the decarbonization of the energy system on behalf of mission-driven investors, regulators, and other stakeholders seeking to accelerate the transformation of the grid.

Twenty First Century Utilities, Washington, D.C. *Senior Advisor*, 2019 – present; *Managing Director: Utility Transformation,* 2015–2019.

Worked to transform, through acquisition and operation, regulated utilities with a 21st century model that drives mass adoption of clean, low-cost energy producing and energy saving technologies. Advanced utility of the future policies, operations, technologies, and governance inclusive of grid optimization, de-carbonization of utility-scale fleet, implementation of TFC Utilities' Million Rate Base Market Platform, and achieving sustainable business value.

Environmental Defense Fund, *Associate Vice President, EDF Clean Energy Program,* 2013–2015.

Led national program advocating regulatory reform to help modernize U.S. energy infrastructure, accelerate deployment of clean technologies into the nation's electric system, and break down the regulatory and financial barriers to broad-scale adoption of renewable energy, energy efficiency, and other innovative ways to generate, distribute, and use energy. Managed a team of over 30 individuals and an annual budget of $11 million dollars.

Public Utilities Commission of Ohio, Columbus, Ohio. *Commissioner,* 2008–2012.

In addition to customary responsibilities of a Commissioner, initiated a national pilot partnership with the United States Department of Energy (U.S. DOE) for combined heat power; served as Co-Chair 2012 National Electricity Forum, Co-Chair, State and Local Energy Efficiency Action Network Driving Ratepayer-Funded Efficiency Working Group (also Chair Sub-Committee for Utility Financial Incentives), Co-Leader U.S. Agency for International Development (U.S. A.I.D.)/NARUC meeting with National Electricity Regulatory Commission of Ukraine (Kiev, Ukraine, September 2011), and a member of the National Association of Regulatory Utility Commissioners (NARUC):

- Task Force on Environmental Regulation and Generation (2012)
- Committee on Critical Infrastructure (also served as Vice Chair) (2010–2012)
- Committee on Electricity (2008–2012)

Department of Public Utilities, City of Columbus, Columbus, OH. *Director*, 2003–2006, *Deputy Director for Operations,* 2001–2003.

Led municipal water, wastewater, and electric utility with annual operating budget of $400 million dollars, an annual capital budget of $250 million dollars, and a staff of 1300 people serving the nation's 15th largest city and 22 Central Ohio political subdivisions. Established and successfully managed $2.5 billion dollar capital engineering and construction program, the largest ever undertaken by the City of Columbus. Completed extensive restructuring of utility rate models and design for the first time in two decades to validate cost of service. Managed successful water quality-focused environmental initiatives involving extensive stakeholder outreach and public education, including the development and adoption of the Hellbranch Run Watershed protection Overlay and Clean Water Act Facilities Plan.

Office of the Mayor, City of Columbus, Ohio, Columbus, OH. *Policy Advisor*, 2000.

Provided advice on public policy issues including health, environment, public utilities, housing, public safety, and development to support the launch of the Mayoral administration of Michael B. Coleman.

Office of the City Attorney, City of Columbus, Columbus, OH. *Assistant City Attorney,* 1997–2000.

Represented City of Columbus for municipal law issues related to environmental, health, and safety matters including environmental permitting (NPDES, Title V, MS4), regulatory enforcement (industrial pretreatment, fire code, storm water development), compliance counseling (RCRA, OSHA, Clean Drinking Water), environmental liability management (PCB disposal, real estate), and contracts.

Commonwealth of Pennsylvania, *Assistant Counsel, Office of Chief Counsel,* 1996–1997.

Served as counsel to the Department of Environmental Protection concerning Superfund, drinking water, wastewater, solid and hazardous waste, and air pollution.

Cheryl L. Roberto, Esq. *Owner,* 1993–1996.

Built boutique law practice specializing in environmental matters; representative clients included City of Erie, Pennsylvania, Erie Sewer Authority, and Erie County Department of Health.

State of Ohio, Columbus, OH. *Assistant Attorney General,* 1987–1992.

Represented the State of Ohio in Environmental and Consumer Protection matters through administrative proceedings, civil actions, and criminal prosecutions concerning wastewater, solid and hazardous waste, and air pollution.

EDUCATION

Moritz College of Law, The Ohio State University, Columbus, OH
Juris Doctor, 1987. Member, Journal of Dispute Resolution. Recipient, University Scholarship and Caris Fellowship. Founding Member, Board of Directors for the Student Funded Fellowship.

Kent State University, Kent, OH
BA, Political Science, *cum laude*, 1984.

Graduated with General Honors from the Honors College. Omicron Delta Kappa and Pi Sigma Alpha. Recipient of Manchester Cup, Junior Service Award, Sophomore Leadership Award, Honor's Scholarship. Honor's Dissertation adopted and implemented by K.S.U. Board of Trustees: "Student Leadership Compensation Model for Kent State University," KSU Library Archives, Honors Papers (1984).

CONTINUING EDUCATION

Harvard University, John F. Kennedy School of Government, Cambridge, MA
Executive Education Certificate of Completion: Strategic Management of Regulatory and Enforcement Agencies, 2012.

University of Colorado, Silicon Flatirons Center, Boulder, CO
Institute for Regulatory Law and Economics, Seminar, May 2012.

Scott Hempling Attorney at Law LLC, Electricity Law Update Seminar, March 2012.

American Law Institute/American Bar Association
42nd Annual Advanced Course of Study in Environmental Law, February 2012.

SNL Center for Financial Education, Essentials of Regulatory Finance, June 2011.

National Regulatory Research Institute, Electricity's Current Challenges: Capital Investment, Renewables, Energy Efficiency, "Modern" IRP, and Transmission. January 2011.

Michigan State University, East Lansing, MI
Advanced Regulatory Studies Program, "Ratemaking, Accounting, and Economics," September 2010.

HONORS AND AWARDS

Inspiring Efficiency Leadership Award, January 2013.
Presented by the Midwest Energy Efficiency Alliance to the organization or individual in the 13-state region who has served as a strong leader in support of energy efficiency in their city, state, region, company, or community.

BOARDS AND COMMISIONS

- Executive Group for the State and Local Energy Efficiency Network (2012–present)
- Board of Directors of the National Regulatory Research Institute (NRRI) (2012)
- Financial Research Institute (FRI) Advisory Board (2011–2012), Chair, Hot Topic Hotline Committee (2012)
- Audubon Ohio, Board Member (2007–2008)
- Franklin County Planning Commission, Member (2001–2006)

- Solid Waste Authority of Central Ohio, Board Member (2003–2006); Engineering, Operations and Compliance Committee Chair
- Mid-Ohio Regional Planning Commission, Member (2003–2006); Greenways Steering Committee Chair; Member Public Works Integrating Committee
- Community Research Partners, Board Member (2000–2002)

PRESENTATIONS

Roberto, C. 2017. "Aligning Economic Incentives: Evolution of the Utility Business Model." Hawaii Clean Energy Law and Finance. Honolulu, HI. July 21, 2017.

Roberto, C. 2017. "TFC's Million Rate Base Model." National Association of Regulatory Utility Commissioners Committee on Energy Resources and the Environment. May 15, 2017.

Roberto, C. 2017. "Creating a Resilient Energy Economy." Maui Energy Conference. Maui, HI. April 6, 2017.

Roberto, C. 2016. "A Twenty First Century Utility." Department of Energy Quadrennial Energy Review Second Installment Public Meeting. Atlanta, GA. May 24, 2016.

Roberto, C. 2016. "What is Sustainable Electricity." Electric Power Research Institute ENV-VISION: Environmental Vision – An International Electricity Sector Conference. Washington, D.C. May 10, 2016.

Roberto, C. 2016. "Utility Transformation: Opportunities for Jobs, our Communities & the Planet." Florida Women in Energy Conference. April 15, 2016.

Roberto, C. 2016. "Confluence of Environmental & Economic Regulation." Ohio Bar Association Environmental Law Conference. Columbus, OH. April 14, 2016.

Roberto, C. 2016. "Can Ohio Meet the Clean Power Plan?" John Glenn College of Public Affairs Dialogue. January 21, 2016.

Roberto, C. 2015. "Right to Data Access." SmartGrid Consumer Collaborative. August 26, 2015.

Roberto, C. 2015. "Success Factors: Career Profiles of Women Leaders." National Association for Environmental Management Women's EHS & Sustainability Leadership Roundtable. San Antonio, TX. April 16, 2015.

Roberto, C. 2015. "Smart Grid: Lessons Learned." Energy Thought Summit 2015. Austin, TX. March 25, 2015.

Roberto, C. 2015. "Decarbonizing the Energy Supply." Energy & Climate Change: 15th National Conference and Global Forum on Science, Policy, and the Environment. January 27, 2015.

Roberto, C. 2014. "Clean Energy Policy -- Looking Ahead to 2020." Forum 20/20: Innovation and the Future of CleanTech. October 29, 2014.

Roberto, C. 2014. "2014 EPRI-TVA Environmental Benchmarking Forum, Charlotte, NC, October 6, 2014.

Roberto, C. 2014. “Product Innovations for Retail Customers.” Retail Energy Supply Association’s 2014 Energy Competition Symposium. Columbus, Ohio. October 2, 2014.

Roberto, C. 2013. “Policies Matter: Practical Approaches for Regulators to Encourage CHP.” WVU Law Center for Energy & Sustainable Development Energy Conference 2013. April 24, 2013.

Roberto, C. 2013. “Enhancing Industry through Industrial Energy Efficiency & Combined Heat and Power.” National Governors Association Policy Academy. March 4, 2013.

Roberto, C. 2013. “Breaking Through the ‘Grid’-lock.” ARPA-E Energy Innovation Summit. February 26, 2013.

Roberto, C. 2013. “Investing in Combined Heat and Power: Benefits and Challenges.” National Association of Regulatory Utility Commissioners Winter Meeting. February 5, 2013.

Roberto, C. 2013. “Should There Be a Change to Cost Effectiveness Testing?” 2013 Midwest Energy Solutions Conference. January 17, 2013.

Roberto, C. 2013. “Working Together to Advance Energy Efficiency: Partnerships for Tackling Persistent Barriers & Achieving Results.” Department of Energy. January 16, 2013.

Roberto, C. 2013. “Transmission Cost Allocation: What Lies Ahead?” Harvard Electricity Policy Group Sixty-Eighth Plenary Session. October 11-12, 2012.

Roberto, C. 2012. “What is the future design of the regulatory process?” 2012 Financial Research Institute Symposium: Emerging Issues in the Management of the Regulatory Interface, September 19, 2012.

Roberto, C. 2012. NARUC/FERC Forum on Reliability and the Environment. February 7, 2012.

Roberto, C. 2012. “Testing…Testing: Are We Getting the Most Value out of Cost-Effectiveness Tests for Energy Efficiency?” Mid-Atlantic Conference of Regulatory Utilities Commissioners 17th Annual Education Conference. June 26, 2012.

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1. CORE ELEMENTS OF MULTI-YEAR RATE PLANS

Multi-year rate plans (MRPs) are widely used around the world and have been in place for many decades in a variety of industries. MRPs are also known as "price cap regulation" or "revenue cap regulation." These approaches have also been referred to as "hands-off regulation" because the utility's costs are not closely examined during the duration of the plan. Instead, the utility's revenues are de-linked from its actual costs in combination with a rate case moratorium (typically lasting from three to five years).

Jurisdictions typically implement MRPs to achieve some or all of the following goals:

- Provide the utility with cost containment incentives
- Encourage innovation by allowing the utility to manage business decisions with greater flexibility.
- Reduce regulatory costs and burdens.
- Provide utilities with greater regulatory guidance and assurance regarding investments in new and innovative technologies to better align utility investments with energy policy goals.

Modern MRPs generally cap allowed revenues, rather than prices, in order to reduce the utility's throughput incentive and encourage the utility to focus on cost reductions rather than increasing revenues. The utility is typically allowed to retain some or all of the savings that it achieves through cost reductions during the duration of the rate plan.[1]

Under an MRP's rate case moratorium, the utility must refrain from filing a new rate case for the duration of the plan. This moratorium generally lasts three to eight years and ensures that the utility cannot simply come in for a new rate case if costs and revenues diverge. This shifts the risk associated with poor utility cost management to utility shareholders, rather than ratepayers, which strengthens the utility's cost containment incentives.

During the rate plan, revenues may either be held at a fixed level or be adjusted according to a pre-defined formula called an "attrition relief mechanism" or "ARM." An ARM may be based on an external cost index (such as inflation), cost forecasts, or a combination of the two. Importantly, the formula does not track the utility's *specific* costs. As explained in the Edison Electric Institute's survey of alternative

[1] However, as discussed in sections 3.1 and 4.2, when the utility's allowed revenues for capital investments are based on capital cost forecasts rather than external indexes, jurisdictions often require the utility to return any under-spend to ratepayers.

regulation mechanisms, "[t]he rate adjustments provided by ARMs are largely "external" in the sense that they give a utility an *allowance* for cost growth rather than reimbursement for its *actual* growth."[2]

In this manner, an MRP is similar to traditional cost of service regulation with a revenue decoupling mechanism, since the utility's costs do not necessarily equal revenues between rate cases, but the utility is still allowed to recover its allowed revenues (regardless of changes in sales). The primary differences from cost of service regulation with decoupling are:

- Allowed revenues can be increased annually through an ARM instead of frozen, and
- The utility agrees to not file another rate case for a set number of years (i.e., a rate case moratorium).

Because revenues do not increase in lock step with costs, the utility has an incentive to reduce costs to increase its profits for the duration of the rate plan. At the end of the MRP term, these cost reductions can then be passed on to ratepayers when rates are reset in a rate case.

To summarize, there are four key design elements that are critical to MRPs:

1) **Revenue Cap:** Revenues are capped at certain pre-determined levels.
2) **Attrition Relief Mechanism (ARM):** The initial year revenues may be escalated based on an index or cost forecast determined at the outset of the rate plan. Cost trackers may be added to the ARM for certain costs, particularly "exogenous" costs that the utility has no control over.
3) **Rate Case Moratorium:** A "stay-out" provision limits the ability for rates to be reset during the plan.
4) **Incentive to Improve Efficiency:** Utilities are incentivized to reduce costs during the plan by retaining some or all of the savings from efficiency gains.[3]

While MRPs can provide strong cost containment incentives and reduce regulatory burden, they also present two key risks. First, the utility's costs may deviate substantially from its allowed revenues during the rate plan. Second, the revenue adjustments provided by an index may not provide adequate revenue for new and unusual investments.

To address the first concern, regulators have often implemented consumer protection measures, such as earnings sharing mechanisms, to ensure that the utility does not over-earn excessively. For example, the utility may be allowed to earn 200 basis points above its allowed ROE, but beyond that it must share some of the extra earnings with customers.

[2] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 34.

[3] Conversely, ratepayers are protected from poor utility performance during the rate plan by being insulated from some or all of any increase in costs above the revenue cap.

To address the second concern, certain costs may be pulled out of the MRP and treated separately. For example, Massachusetts removed Eversource Energy's grid modernization investments from the MRP and is allowing recovery of those costs through a separate "Grid Modernization Factor."

MULTI-YEAR RATE PLAN EXAMPLE: MASSACHUSETTS

Overview: Eversource Energy operates under an MRP that uses a revenue-indexing mechanism to adjust base rates, plus reconciliation of certain exogenous costs. The MRP has a five-year stay out period.

Revenue Index: Eversource's MRP allows for an adjustment of Base Rates using the rate of input price inflation representative of the electric distribution industry, less offsets for productivity and a consumer dividend.

Annual Adjustments: Effective January 1 of each year, the utility's Base Revenue Requirement is adjusted through an adjustment formula equal to the percentage change in the US Gross Domestic Product Price Inflation (GDPPI), plus a productivity adjustment of 1.56% minus a consumer dividend of 0.25%, plus an adjustment for exogenous costs.

Reconciliation of Exogenous Costs: Exogenous costs must (1) be beyond the utility's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives; (3) be unique to the electric industry as opposed to the general economy; and (4) meet a threshold of "significance" of $5 million. The utility must present supporting documentation and rationale to the commission for consideration. Once allowed by the commission, the cost is recovered or returned in a separate factor to be reviewed and approved by the commission.

Recovery of Pre-authorized Grid Modernization Costs: All grid modernization-related capital and O&M expenditures are recovered separately and are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the Grid Modernization Factor shall not exceed the preauthorized three-year budgets.

Customer Protections: Earnings Sharing provides an important protection for customers in the event that expenses increase at a rate much lower than the revenue increases generated by the MRP revenue index. If the utility's actual ROE exceeds the utility's allowed ROE by 200 basis points, 75% of any additional earnings must be shared with customers.

See: *NSTAR Electric Co. d/b/a Eversource Energy, Tariff Sheets M.D.P.U. No. 59A, filed February 16, 2018.*

2. CONTRAST TO FORMULA RATE PLANS

2.1. What is a Formula Rate Plan?

Both MRPs and formula rate plans (FRPs) feature formulas, thereby creating some confusion regarding the differences between the two approaches. The primary distinction is that formula rate plans formulaically ensure that revenues track costs, often measured as deviations in ROE from the utility's target ROE. If a utility's earned return is above its ROE target, it will be required to reduce its rates. Likewise, if a utility's earned return is below its target return it will be allowed to increase its rates. In contrast, MRPs do not adjust revenues to equal costs during the plan.[4]

A report by Edison Electric Institute describes a formula rate plan as "essentially a wide-scope cost tracker designed to help a utility's revenue track its cost of service."[5] The report explains how this works as follows:

> Earnings surpluses or deficits occur when revenue and cost are not balanced. FRPs have earnings true up mechanisms that adjust rates so that earnings variances are reduced or eliminated…. The earnings true up mechanism plays a key role in an FRP. Some mechanisms compare the earned ROE to the target ROE and then calculate the rate adjustment needed to reduce the ROE variance. Others adjust rates for the difference between revenue and a pro forma cost of service calculated using a rate of return target.[6]

In other words, formula rate plans true up revenues to costs once the ROE deviates from the allowed ROE by a certain amount. These true-ups are generally accompanied by some form of commission review and approval, but these reviews are more streamlined than those that occur in a general rate case.

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[4] With the possible exception of a limited set of cost trackers or reconciliations for specific types of costs.

[5] Mark N. Lowry, Matthew Makos, and Gretchen Waschbusch, "Alternative Regulation for Emerging Utility Challenges: 2015 Update" (Edison Electric Institute, November 11, 2015), 47.

[6] *Ibid*.

Alabama Power's Formula Rate Plan

Overview: Alabama Power Company operates under an FRP called the "Rate Stabilization and Equalization plan." Each year, the Alabama Public Service Commission compares the utility's projected ROE for the next year to its authorized ROE. If necessary, the utility's base rates are adjusted to keep the expected ROE within the authorized range, following a review of the reasonableness of the utility's costs.

Reconciliation Process: By December 1 of each year, the utility provides the commission with its projected ROE for the next year, together with an analysis of the main causes of any deviations from its authorized ROE and the need for any rate adjustment. During December, parties review and discuss the need for the rate adjustment, with any adjustments going into effect in January.

Customer Protections: Several customer protection measures are in place. Annual rate adjustments are capped at 5% to reduce rate shock. Once the utility's revenues are adjusted to match its projected costs for the upcoming year, the onus is on the utility to keep costs in check. If the utility fails to achieve its allowed ROE, no further reconciliation is made. However, if the utility's ROE exceeds its allowed ROE, then the excess is refunded to customers.

__See:__ Laurence Kirsch and Mathew Morey, "Alternative Electricity Ratemaking Mechanisms Adopted by Other States" (Christensen Associates Energy Consulting, May 25, 2016), p. 11.

Entergy Arkansas, Inc.'s Formula Rate Plan

Overview: As required by 2015 Ark. Acts 2015 725, §3, formula rate plans in Arkansas use a formula based on the difference between a utility's target and earned return. If the utility's earned return exceeds its target return by 50 basis points, it is required to reduce its rates. Likewise, if the utility's earned return falls below its target return by 50 basis points, it is allowed to increase its rates.

Cost Forecasts: The utility may choose to use a projected test year or a historical test year. If a projected test year is used, the utility must file its cost forecasts in July of each year for the next calendar year period.

Reconciliation Process: If a projected test year is used, rate changes must include an adjustment to net any differences between the prior formula rate review test period change in revenue and the actual historical year change in revenue for that same year.

Regulatory Review: The review of cost forecasts, reconciliation, and approval of new rates occurs in a 180-day process that includes a public hearing.

Customer Protections: Annual rate adjustments for each rate class are capped at 4%.

See: AR Code § 23-4-1207 (2015)

2.2. Concerns with Formula Rate Plans

Commissions have generally been reluctant to adopt formula rate plans due to the problematic incentives they provide and recognition that these plans shift risk onto ratepayers. For example, the Maryland Public Service Commission noted that problems with formula rate plans include "tendency to shift financial risks toward customers, a concern that automatic adjustments may curtail the thorough review of utility costs, and reduced incentives for utilities to control costs."[7]

These concerns have been borne out by experience in jurisdictions where FRPs have been implemented. For example, in 2015, Act 725 was passed in Arkansas requiring that the Commission approve formula rate plans, but capped revenue increases under an FRP to 4% per year. Following passage of the Act, Entergy Arkansas, Inc. filed for a formula rate plan. In each subsequent year, Entergy has requested rate increases exceeding 4%, leading to concerns that the formula rate plan has not provided appropriate cost containment incentives. As explained by the Commission Staff,

> An FRP is an annual rider. It fundamentally accomplishes a higher level of certainty of recovery thus reducing risk to the utility…. The ability to increase revenues 4% each year is a considerable risk reduction for the utility.[8]

More specifically the Staff noted that an FRP:

- Reduces the time afforded for review of utility costs, which can serve to incentivize spending;
- Allows projections on projections, which incentivizes spending as compared to a regulatory framework where projections are based on what is otherwise historical information from which to make known and measurable changes;
- Incentivizes spending due to the annual rate adjustments. Once the FRP framework is selected by a utility, an outcome of a 4% increase each year (over the prior year) is less subject to challenge as long as the costs are prudently incurred and calculated in accordance with the tariff. The traditional regulatory tools in the Commission's toolkit are more limited under the FRP framework as the Commission has recognized;
- The unstated implication of the FRP statute is that the risk of an earnings review is effectively eliminated. There is no clear incentive to contain costs between annual FRP 4% increases. While the FRP framework states the rate change may be an increase or a decrease, the likelihood of a decrease is highly unlikely.[9]

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[7] Maryland Public Service Commission, Order 89226, PC51, August 9, 2019, at 53.

[8] AR PSC Staff, Initial Brief Pursuant to Order No. 18, Docket 16-036-FR, January 1, 2019, at 17.

[9] *Id.,* at 18-19.

In its order, the Arkansas Commission agreed with Staff, stating that "many of the FRP processes, including a reduction in the time afforded for review, the use of projections, and annual rate adjustments do little to incentivize a utility to control its costs as compared to traditional ratemaking."[10]

In contrast, multi-year rate plans provide strong efficiency incentives precisely by *avoiding* cost true-ups. As noted in a Brattle report filed by the Joint Utilities in Maryland, "Multi-year rate plans typically have reconciliations **more limited in scope** and typically focused on capital expenditures, **to the extent that reconciliations are included at all** [emphasis added]."[11]

FORMULA RATES AND MINNESOTA'S MRP

When Minnesota was developing its rules for multiyear rate plans, various parties proposed different approaches to revenue adjustments during the rate plan.

- The Minnesota utilities favored favor formula rates, arguing that these rates could be more useful because they would adjust to reflect the latest data.
- Other parties opposed the use of automatic formulas for the purpose of adjusting rates to reflect new costs. They argued that formula rates would reduce a utility's incentive to operate efficiently and would be burdensome to supervise. Instead, these parties favored fixed multiyear rates. The rate case would establish the rates to be charged in each year of the multiyear rate plan; the rates for the first year might differ from the rates for later years, but the base rates for all years would be known by the end of the rate case.

Ultimately the Minnesota Public Utilities Commission declined to approve multiyear rate plans that rely on formula rates, noting that such rates reduce a utility's incentive to manage its costs. Moreover, the Commission observed that formula rates are unnecessary to achieve the purpose of a multiyear rate plan, stating that "Fixed multiyear rates permit prices to adjust over time to reflect anticipated changes in a utility's circumstances, yet can be established in a fact-driven ratemaking process built on a substantial evidentiary record." Consequently, the Commission directed utilities to propose fixed rates for each year of their plan when filing a multiyear rate plan.

See: Minnesota Public Utilities Commission, Docket No. E,G-999/M-12-587, Order Establishing Terms, Conditions, and Procedures for Multiyear Rate Plans, June 17, 2013, at 6-7.

[10] Arkansas Public Service Commission, Order No. 21, Docket 16-036-FR, July 5, 2019.

[11] The Brattle Group, Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates, Joint Utilities' Joint Initial Comments, Maryland PC51, March 2019.

3. ESCALATING REVENUES DURING THE MRP

Attrition relief mechanisms escalate a utility's allowed revenues over the course of an MRP. The ARM can be based on either an external price index or a cost forecast. With cost forecasts, information asymmetry is a serious concern, which has led many jurisdictions to opt for an index-based approach. We discuss both approaches below.

3.1. Revenues Escalated Based on Cost Forecasts

An ARM based on forecasts increases revenue by predetermined percentages in each plan year based, at least in part, on a utility's cost projections. The percentages can be different in each year, or the total increase can be levelized across the years.

To determine the revenue requirement for each year, both older capital investments (i.e., depreciation expense) and new capital additions must be accounted for. Depreciation expense is straight-forward to calculate, as older capital simply continues to depreciate. As noted in a recent report published by Lawrence Berkeley National Laboratories, the controversial issue lies in estimating the value of plant additions during the plan. The report explains that shortcuts are sometimes taken when estimating plant additions. For example:

- Plant additions may be set for each plan year at the utility's average value in recent years
- Plant additions may be set for each plan year at the value calculated in the test year of the most recent rate case
- Operation and maintenance expenses can be forecasted using index-based formulas.[12]

ARMs based on cost forecasts enable the utility's revenues to accommodate unusual investment trajectories, such as a capital investment surge. Since the ARM generally operates as a cap on revenues, it provides an incentive for the utility to ensure that actual investment costs are kept under the cost cap. However, forecasted ARMs are notoriously challenging for regulators, as it is difficult to ensure that the forecasts are reasonable due to asymmetry of information.

The National Regulatory Research Institute describes this issue as follows:

> Information asymmetry reflects the relatively less knowledge that a regulator has (relative to the utility's) on the correlation between forecasted costs and utility-management competence. When a utility files a cost forecast, how does the regulator know whether it reflects competent management? The analyst or auditor can evaluate the

[12] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 4.2, https://escholarship.org/uc/item/4r13j347.

> forecast applying state-of-the-art techniques; still, however, a level of uncertainty remains that leaves unknown the utility's level of managerial competence embedded in the forecast.[13]

Sophisticated approaches to reducing forecast bias are available, such as the menu approach used in the United Kingdom. Under this approach, the utility can choose among various combinations of allowed revenues and earnings sharing mechanisms, such as a plan with high revenues but for which it retains only a small portion of any cost savings, or a plan with low revenues but under which it can retain a higher portion of cost savings.

Regulators may also conduct independent benchmarking and engineering studies to determine the reasonableness of cost forecasts, but such endeavors are costly. In addition, regulators can check the accuracy of past cost forecasts and create performance incentive mechanisms for forecasting accuracy. Where cost forecasts are used to set allowed revenues, they are often accompanied by a one-way (downward) reconciliation mechanism, as is done in Minnesota and New York.

MRP Based on Cost Forecasts with One-Way Reconciliations

In 2017, the Minnesota Public Utilities Commission approved a settlement regarding Xcel Energy's multiyear rate plan application. The utility's initial application requested revenue increases supported by substantial documentation of the utility's proposed cost of service. During settlement proceedings, the annual revenue requirements were adjusted downward substantially, and generally became divorced from actual project costs.

The Minnesota Commission ultimately found the settlement reasonable, despite it no longer being tied to specific project costs, as the yearly rate increases were less inflation and significantly less than what Xcel initially proposed. Further, the settlement prohibited Xcel from filing another rate case until for four years or from seeking to institute any new riders for four years.

As an additional consumer protection measure, the settlement adopted a one-way capital-spending true-up, meaning that Xcel will make refunds if it spends less than it budgeted but cannot increase rates if it spends more. The true-up is based on aggregate capital spending, rather than individual projects. The Commission found that a true-up based on the aggregate amount of capital spending was reasonable given that Xcel's budget included approximately 1,800 capital projects. Nonetheless, the Commission also required that Xcel work with the Commission and Department of Commerce Staff to develop an annual capital-projects true-up compliance report that provides more granular data regarding project spending.

See: *Minnesota Public Utilities Commission, Findings of Fact, Conclusions, and Order, Docket E-002/GR-15-826, June 12, 2017.*

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[13] Costello, "Multiyear Rate Plans and the Public Interest," 35–36.

3.2. Revenues Escalated Based on External Indexes

External indexes have historically been the preferred means by which to set a utility's allowed revenue requirements for future years of an MRP. In some cases, different categories of costs are escalated at different rates based on separate cost indexes. For example, IHS Global Insights provides cost escalation forecasts that are specific to the utility industry and are broken out by category of cost.

Indexes may be coupled with a "productivity factor." This productivity factor is often denoted as "X" and generally reflects the multifactor productivity of a group of peer utilities. In addition, a stretch factor (or "consumer dividend") may be added to the productivity factor in order to provide customers with a share of the benefit of the stronger performance incentives that are expected under the plan.[14] Further, "Y" and "Z" factors for unusual costs or costs outside of the utility's control may be added, as discussed in Section 4.1 below. The resulting escalation formula may look something like this:

$$\textit{Revenue Requirement}_{\textit{Year 2}} = \textit{Revenue Requirement}_{\textit{Year 1}} * (1 + \textit{Inflation} - X) + Y + Z$$

The California Public Utilities Commission has repeatedly rejected ARMs based on the utility's specific cost forecasts, opting instead to use inflation forecasts for different types of costs. In 2019, the California Commission adopted a capital escalation rate equal to the unweighted average of capital escalation rates across seven categories of costs, as shown in the table below:[15]

Unweighted Average of Capital Escalation Rates

	Year	
	2019	2020
Total Steam Production Plant	2.51%	2.54%
Total Hydraulic Production Plant	2.45%	2.40%
Total Other Production Plant	2.11%	2.64%
Total Transmission Plant	2.63%	2.62%
Total Distribution Plant	3.14%	3.18%
General Plant	1.82%	1.81%
Total Nuclear Palo Verde	2.55%	2.46%
Unweighted Average Across 2019-2020		**2.49%**

Escalating allowed revenues based on an external index permits the utility to continue making necessary investments and avoid revenue attrition, while avoiding concerns regarding strategic behavior (i.e., gaming of forecasts) and information asymmetry that are present in forecast-based ARMs.

3.3. Conclusions Regarding Revenue Escalation Approaches

To summarize, index-based revenue adjustment mechanisms have many advantages over cost forecasts:

[14] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), 4.2, https://escholarship.org/uc/item/4r13j347.

[15] California Public Utilities Commission, D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company, May 24, 2019, at 284.

- External cost indexes do not require that specific costs be reviewed and pre-approved at the beginning of the MRP. In contrast, basing revenue adjustments on a cost forecast essentially asks that the regulator pre-approve investments and their associated costs. This unduly shifts risks from the utility to the regulator and ultimately to ratepayers. Further, it increases the administrative burden for regulators and stakeholders.
- External cost indexes do not rely on utility cost forecasts that may be subject to error or may be over-inflated.

An index-based mechanism avoids the above challenges, but still allows utility revenues to increase over the term of the MRP, allowing for longer time between rate cases, without unduly shifting risk to ratepayers.

4. Reconciliation of Costs in MRPs

Full reconciliations of costs and revenues in an MRP would be antithetical to the definition of an MRP. If revenues are trued up to equal the utility's actual costs, it erodes the utility's efficiency incentive, since the utility no longer benefits from implementing cost efficiencies and endures little risk if its costs exceed expectations. Broad annual true-ups would also essentially create annual rate cases, increasing the regulatory burden exponentially and erasing the benefits of the stay-out period.

However, some jurisdictions incorporate limited cost true-ups in MRPs. These true-ups often take the form of cost trackers for categories of costs that meet specific criteria and are limited in scope, such as costs that are outside the utility's control, or for a specific unusual capital investment.

When considering whether to implement any type of cost reconciliation mechanism, it is important to consider the impact on a utility's efficiency incentive and the impact on regulatory burden.

- If revenues are reconciled to actual costs, then the utility has reduced incentive to contain those costs.
- Under a broad reconciliation mechanism, the review required to determine that costs are reasonable imposes additional regulatory burden.

As emphasized by NRRI, "Regulators should avoid resetting annual rates based on a utility's actual cost in the absence of a prudence review…."[16] This means that any annual true-up based on actual costs would require a thorough examination of the utility's costs for prudence, which increases the regulatory burden. For these reasons, trackers and reconciliations should be used sparingly.

[16] Ken Costello, "Multiyear Rate Plans and the Public Interest," National Regulatory Research Institute, at 23.

4.1. Types of Costs that Are Often Reconciled in MRPs

In MRPs, cost reconciliations generally take some or all of the following forms:

A. Reconciliations for certain unusual, large investments
B. Reconciliations for recurring pass-through or mandated costs
C. Reconciliations or deferrals of one-time extraordinary costs

A. Reconciliations for Unusual, Large Costs ("K-Factor" Costs)

Large, unusual investments can be difficult to predict and incorporate into an MRP. Further, some investments may have impediments associated with their implementation, such as excessive risk or high capital costs. For example, the Massachusetts Department of Public Utilities found that utilities "may hesitate before making investments beyond what they deem necessary to ensure safe and reliable service, and that this reluctance may even exist "when the investments are cost-beneficial for a company but involve high capital costs, combined with regulatory lag and the potential for disallowed costs."[17]

For these reasons, large, unusual investments are sometimes addressed outside of an MRP's standard revenue requirement through a capital cost tracker or other reconciliation mechanism, often generically referred to as a "K-factor." In Massachusetts, such a factor was established for certain "foundational" grid modernization investments, as discussed in the box below.

[17] Massachusetts Department of Public Utilities, Order D.P.U. 12-76-A, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid, December 23, 2013, at 25. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9241637

RECONCILIATION OF GRID MODERNIZATION COSTS IN MASSACHUSETTS

Utilities may hesitate before making investments with high capital costs, particularly when combined with regulatory lag and the potential for disallowances. To encourage grid modernization, the commission in Massachusetts approved a targeted cost recovery mechanism called the "Grid Modernization Factor" or "GMF" for investments that are preauthorized by the commission.

Pre-authorization of investments and budgets: All grid modernization-related capital and O&M expenditures are subject to a targeted cost recovery cap. Specifically, the level of expenditures eligible for cost recovery through the GMF shall not exceed the preauthorized three-year budgets.

Cost Recovery: Costs are only eligible for recovery after the expenses have been incurred and the investments have been placed in service. The utilities file annual GMF rate adjustment and reconciliation filings comprised of: (1) actual, eligible preauthorized expenditures from the prior grid modernization plan investment year; and (2) a reconciliation component in the second year and beyond. Interest on over- or under-recovery of the revenue requirement is calculated on the average monthly balance using the customer deposit rate.

Annual Reconciliation Filings: On an annual basis, the utilities must file testimony and supporting exhibits with full project documentation of all grid modernization capital projects placed into service during the plan investment year and documentation of O&M expenses. The utilities must demonstrate that the costs sought for recovery are preauthorized, incremental, prudently incurred, in service, and used and useful (where applicable). Additionally, the filing shall also describe any cost variances as defined in the Companies' capital authorization policies, provide a demonstration that the proposed factors are calculated appropriately, and provide bill impact estimates.

***See:** Massachusetts Department of Public Utilities, Order D.P.U. 15-122, May 10, 2018, at 216-235. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9163507*

B. Reconciliations for Recurring Pass-Through or Mandated Costs ("Y-Factor" Costs)

Recurring costs that are volatile and outside of utility control may be fully or partially reconciled during an MRP using cost trackers or deferral mechanisms. In Alberta, these costs are referred to as "Y-Factor" costs. The Alberta Commission established the following criterial for costs eligible for Y-Factor treatment:

1) The costs must be attributable to events outside management's control.
2) The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
3) The costs should not have a significant influence on the inflation factor in the [MRP revenue] formulas.
4) The costs must be prudently incurred.

5) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.[18]

New York allows reconciliations only for costs that "are difficult to forecast with certainty and are largely beyond the direct control of utility management."[19] In New York, reconciliation and/or deferral accounting mechanisms have been used for costs including:

- Taxes
- Pensions/other post-employment benefits (OPEBs)
- Environmental remediation costs
- Regional Greenhouse Gas Initiative ("RGGI") costs
- System Benefits Charges
- Energy Efficiency Portfolio Standard charges and Demand Side Management costs
- New York Public Service Law §18-a regulatory assessment (for commission costs)
- Market supply charges
- Cost of the Low Income customer charge discounts[20]

We note, however, that some of these reconciliations have been only partial in order to preserve some incentive for the utility to manage the costs efficiently. In Consolidated Edison's MRP, if property taxes varied in any Rate Year from the projected level provided in rates, only 80% of the variation would be deferred and either recovered from or credited to customers, subject to a cap on the Company's share equal to 10 basis points on common equity for each Rate Year.[21]

In its order approving ConEdison's MRP, the New York Public Service Commission explained that asymmetrical and partial reconciliations for certain costs "provide the Company an incentive to manage such costs to the extent practicable." The Commission further noted that such reconciliation provisions decrease the volatility of a company's earnings and transfer risk to ratepayers, which allows the Commission to reduce the allowed return on equity in rate proceedings. The Commission explains that this "is one of the prime reasons returns allowed in New York are and can be lower than those in many other jurisdictions."[22] It is reasonable that any reconciliations and reduced risk to the utility be accompanied by a commensurate reduction in the utility's allowed ROE.

[18] Alberta Utilities Commission, Decision 2012-237, September 12, 2012, at 135.

[19] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 26. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1714A09D-088F-4343-BF91-8DEA3685A614}

[20] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014.

[21] Joint Proposal, CASE 09-E-0428- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, November 24, 2009, at 18.

[22] Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, February 21, 2014, at 29-30.

C. Reconciliations of One-Time Extraordinary Costs ("Z-Factor Costs")

In an MRP, true-ups can be appropriate for exceptional costs that have a material effect on the utility's costs, are beyond the control of utility management, and which were incurred reasonably (such as extraordinary storm response costs). For example,

- New York's MRPs allowed cumulative major storm damage expenses in excess of a certain threshold to be deferred. The expenses would be subject to New York Department of Public Service Staff review.[23]

- California has utilized "Z-factors" to reconcile items that meet the following criteria:
  1. The event must be exogenous to the utility;
  2. The event must occur after implementation of rates;
  3. The costs are beyond the control of the utility management;
  4. The costs are a normal part of doing business;
  5. The costs must have a disproportionate impact on the utility;
  6. The costs and event are not reflected in the rate update mechanism;
  7. The costs must have a major impact on overall costs;
  8. The cost impact must be measurable; and
  9. The utility must incur the cost reasonably.[24]

4.2. One-Way Reconciliations of Costs

As discussed above, the most common means of adjusting allowed revenues during the rate plan is the index approach. However, some jurisdictions use cost forecasts, or a combination of external indexes and cost forecasts. Where cost forecasts are used, they are frequently accompanied by one-way (downward) reconciliations of costs.

A key challenge associated with the use of cost forecasts is that the utility has an incentive to inflate cost projections. As the Alberta Public Utilities Commission noted, unless there is a reconciliation mechanism, basing revenues on cost forecasts "creates the opportunity for the distribution utility to benefit from exaggerating its forecasts and puts more pressure on the Commission to ensure the forecasts are reasonable." Further, the Alberta Commission notes its "concerns about over-forecasting and asymmetrical information and finds that an incremental capital mechanism that includes a forecasting component but lacks a true-up is problematic because it incorporates the unacceptable forecasting incentives…"[25]

A one-way reconciliation mechanism reduces the benefit that the utility receives from inflating its cost projections and protects customers from utility under-spend. The one-way nature of the reconciliation

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[23] Joint Proposal, CASE 09-E-0428- Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, November 24, 2009, at 24.

[24] California Public Utilities Commission, D1408032, Authorizing PG&E's GRC Revenue Requirement for 2014-2016, at 661.

[25] Alberta Utilities Commission, Decision 20414-D01-2016, December 16, 2016, at 53.

also encourages the utility to keep costs below the projections and ensures that over-spends are not approved until a prudency review in the subsequent rate case. However, the one-way nature of the reconciliation still incentivizes the utility to inflate its capital projections to ensure that it does not exceed its capital cost forecast. Just as importantly, it provides no incentive to increase efficiency.[26]

Minnesota and New York both use cost forecasts to project revenue requirements associated with capital investments, but have coupled the forecasts with a one-way (downward) reconciliation mechanism. New York's approach is discussed in the box below.

NEW YORK'S "CLAW-BACK MECHANISM"

A one-way reconciliation mechanism is used in New York and referred to as the "Net Plant Reconciliation Mechanism" or "claw-back mechanism." The New York Public Service Commission describes this mechanism for Consolidated Edison as follows:

> If the Company's actual average net plant in service for each of the three categories of capital expenditures is less than that category's projected average plant-in-service balance…, the Company will defer the carrying costs associated with the difference for the benefit of ratepayers. If the Company exceeds the net plant-in-service targets, it must absorb the related carrying costs during the term of the rate plan. Con Edison must justify the need for, the reasonableness of, and its inability to reasonably avoid any such over-target expenditures in its next rate case filing. In addition, the revenue requirement associated with any such Commission-approved over-target expenditures from Rate Year 1, after the term of the rate plan and for the book life of the investment, will be calculated based on an assumption that the over-target expenditures were not financed by both common equity and debt, but rather solely by debt.

See: *New York Public Service Commission, Order Establishing Three-Year Electric Rate Plan, Case 09-E-0428, March 26, 2010, at 11.*

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[26] The California Public Utilities Commission (CPUC) has objected to such claw-back mechanisms precisely because it erodes the utility's incentive to be efficient. The CPUC explains:

> "…we are extending to utility management an opportunity and incentive to find ways to conduct operations for less than projected. When it can do this it flows the benefit to the utility's bottom line, which means profit. In the short term, between general rate proceedings, the shareholders benefit when the company's management can 'do it for less,' and correspondingly, ratepayers ultimately benefit because the productivity improvement will be reflected periodically when there is a comprehensive review of the utility's revenue requirement. Keeping this incentive for utility management is a cornerstone of ratemaking, which leads us to look askance at proposals for immediate 'give backs' of all cost savings to ratepayers. If ratemaking ever becomes so conceptually upside down that utility management loses the economic incentive to exercise its business acumen, California will be in a sad posture and will suffer under utility management which is lethargic with a 'cost plus' mentality."

See: California Public Utilities Commission, D.85-03-042, 17 CPUC2d 246, at 254, as cited in D.19-05-020, Decision on Test Year 2018 General Rate Case for Southern California Edison Company, May 24, 2019, at 152.

5. OTHER COMPONENTS OF MRPS

5.1. Earnings Sharing Mechanisms

Earnings sharing mechanisms are primarily implemented to ensure that utility earnings do not become excessive during multi-year rate plans. The vast majority of these earnings sharing mechanisms are one-way adjustments that cap the potential over-earning of the utility and require that the utility share some of its over-earnings with customers. As noted by the Brattle Group, earnings sharing mechanisms that apply to "utility over earnings (but not under earnings) are in place in 10 states."[27] Only one state (Hawaii) is considering an earnings sharing mechanism for under-earnings as well.

Four states with MRPs have no earnings sharing mechanisms at all, allowing the utility to retain all over-earnings or suffer any under-earnings. Where earnings sharing mechanisms are used, there is the risk that the utility's efficiency incentives will be blunted. Thus, to preserve utility incentives, many of the states with earnings sharing mechanisms also apply a deadband where a utility is not required to share excess earnings with customers.

In Massachusetts, the deadband for earnings sharing is 200 basis points for Eversource. If the utility's ROE exceeds its allowed ROE by 200 basis points, it must return 75% of additional earnings (beyond 200 basis point) to ratepayers. In Iowa, the commission set MidAmerican's allowed ROE at 10% and then required that earnings between 11% and 14% be shared 80% with ratepayers. Beyond an earned ROE of 14%, all of the excess earnings are to be returned to ratepayers.[28]

5.2. Rate Plan Duration

MRPs are usually last between three and five years, although the plans in the United Kingdom last for eight years. There are several distinct advantages to plans that are shorter in duration:

- Shorter plans require less up-front investment in time and resources (modeling, review).
- Shorter plans present less risk associated with getting the forecasts wrong.

However, shorter plans also provide much weaker incentives for a utility to reduce its costs, as any cost reductions will quickly pass on to ratepayers at the time of the next rate case (unless efficiency carryover mechanisms are used).[29]

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[27] Pepco Exhibit J, Witness Zarakas, in FC 1156, The Application of the Potomac Electric Power Company Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia, at 13.

[28] Iowa Utilities Board, Order Approving Settlement, with Modifications, and Requiring Additional Information, Docket No. RPU-2013-0004, March 17, 2014.

[29] Efficiency carryover mechanisms allow for the utility to retain a share of its savings from efficiency improvements for a set period of time when a multiyear rate plan expires. For more information, see Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Lawrence Berkeley National Laboratory, July 2017), at 4.8-4.10, https://escholarship.org/uc/item/4r13j347.

In contrast, longer plans provide greater innovation incentives (due to more time for utility to reap rewards from innovation and efficiencies). Longer plans also reduce the frequency of rate cases and therefore possibly reduce overall costs of regulation.

5.3. Reopener Provisions

Reopeners permit a reassessment of the utility's revenues and costs with the potential to make adjustments. A utility would be expected to request a reopener if it was under-earning, while a regulator or other stakeholder would be expected to request a reopener if they felt the utility was over-earning. However, use of reopeners can dilute incentives for the utility to operate efficiently, since the utility knows it can simply come back in and ask for more revenues, or the utility knows that if it operates too efficiently, its higher earnings will be taken away prematurely. Establishing clear criteria for reopening rate plans at the outset can help avoid reopening rate plans except when absolutely necessary.

In Minnesota, a utility that receives Commission approval of its multiyear rate plan must delay filing a new rate case until after the plan expires. However, utilities still retain the discretion to request rate relief from the Commission under Minn. Stat. § 216B.16, subd. 19 (c).

5.4. Performance Incentive Mechanisms

Under an MRP regulatory framework, utilities retain some or all of the savings achieved through cost reductions. This can create an incentive to cut costs at the expense of service quality. To combat this incentive, regulators have historically coupled MRPs with performance incentive mechanisms (PIMs) to prevent service quality degradation. Increasingly, PIMs are also increasingly being used to promote other outcomes, such as emissions reductions, as well as to ensure that a utility follows through on its commitments, such as investments in grid modernization.

APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR AN ELECTRIC AND GAS MULTI-YEAR PLAN

CASE NO. 9645

DATA RESPONSES REFERENCED

IN THE DIRECT TESTIMONY OF CHERYL ROBERTO

BGE Response to OPC Data Request 13-02
BGE Response to OPC Data Request 28-01(e)

BGE Response to Staff Data Request 74-01(b)

August 14, 2020

Case No. 9645
Baltimore Gas and Electric Co.
Response to OPC Data Request 13
Request Received: 06/30/2020
Response Date: 07/15/2020
Sponsor: Mark D. Case

Item No.: OPCDR13-02

Referring to Commission Order No. 89482 at 35, page 18, where it states that at a minimum, the Pilot Utility should therefore provide in a clear and concise manner: "benefits that consumers should expect as a result of the Pilot Utility's participation and filing of a MRP", please answer the following:

a. What benefits should consumers expect as a result of the Company's MYP?
b. How do the benefits described in (a) above differ from those customers would expect if the Company had filed a traditional rate case?
c. Did the Company quantify the benefits described in its answer to (a) above? If yes, please provide the dollar value and any associated documentation used to calculate those benefits. Please provide any calculations in Excel format with formulae intact. If no, please explain why not?

RESPONSE:

Order No. 89482, page 1, states "In Order No. 89226, the Commission found that the record developed in Public Conference 51 ("PC51") supported the use of a multi-year rate plan ("MRP") as an alternative to traditional ratemaking methods, and determined that a properly constructed MRP can result in just and reasonable rates and yield several benefits over time Among these benefits, the Commission determined that the use of MRPs could shorten the cost recovery period, provide more predictable revenues for utilities and more predictable rates for customers, spread changes in rates over multiple years, and decrease administrative burdens on regulators by staggering filings over several years." Please also see the Direct Testimony of Mark D. Case, pages 17-18, 24-25, and 29-30.

Case No. 9645
Baltimore Gas and Electric Co.
Response to OPC Data Request 28
Request Received: 07/31/2020
Response Date: 08/07/2020
Sponsor: David M. Vahos; Mark D. Case

Item No.: OPCDR28-01[1]

In Mr. Vahos' Direct testimony under the heading, "List of Issues and Major Conclusions," he states as follows:

> The 10.25% return on equity requested in the Company's MYP is based on the 9.9% return on equity recommended by Company Witness McKenzie, adjusted upwards for a performance adder of 35 basis points to align with the midpoint of the upper half of Company Witness McKenzie's recommended cost of equity range. BGE believes that when a utility shows consistent excellent performance and customer satisfaction, that historical performance should positively impact the return on equity authorized by the Commission.

At p. 5 of Mr. Vahos' Direct, he states, "Given that BGE's recent historical operational performance and customer satisfaction results also fall within the top quartile of industry performance, a top quartile ROE award is appropriate."

A. With regard to the above, if the Commission were to deny BGE's request for a performance adder, how (if at all) would BGE's performance be evaluated under the identical metrics? Please explain your response with reasonable specificity.

B. Is it BGE's position that investors who are following this proceeding expect or anticipate the award of a performance basis point adder to whatever return on equity the Commission determines? Whether you answer is in the affirmative or the negative, please explain with reasonable specificity.

C. Is it BGE's position that its customers should expect less than consistent excellent performance if the Commission denies BGE's request for a performance basis point adder? Whether you answer is in the affirmative or the negative, please explain with reasonable specificity.

D. Does BGE agree with the following statement: BGE bears some of the risk of actual costs exceeding forecasted costs and as a consequence must effectively manage its business to achieve this rate of return on equity. Whether you answer is in the affirmative or the negative, please explain with reasonable specificity.

E. With regard to Mr. Vahos' testimony that, "when a utility shows consistent excellent performance and customer satisfaction, that historical performance should positively impact the return on equity authorized by the Commission," please explain why that performance would not already be positively reflected in the ROE ultimately authorized by the Commission without the requested basis point adder.

F. Is it BGE's position that without the grant of its requested performance basis point adder, BGE will not be able to attract the capital (whether through debt issuances, stock issuances or stock price) necessary to run its utility business? Whether you answer is in the affirmative or the negative, please explain with reasonable specificity.

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[1] BGE has determined that this data request and its response do not need to be Confidential and has removed the Confidential designation accordingly.

G. In its "Order Establishing Framework for Multi-Year Rate Plans" (at pp. 26-27), Order No. 89482, Case No. 9618 (February 4, 2020) on establishing a ROE in this case, the Commission stated, "For the Pilot Utility, the Commission agrees that the ROE and capital structure will be set for the duration of the Pilot MRP."

(1) If the Commission were to grant BGE's request for a 35 basis point adder but BGE fell out of the top quartile of industry performance for years 2 and 3 of this multi-year rate plan, how would that be taken into account with respect to the just and reasonableness of the performance basis point adder?

(2) What would be the practical result?

RESPONSE:

Please note that in Part 2 of Company Witness Vahos' Direct Testimony, BGE lowered its requested performance adder to 20 basis points for a total recommended ROE of 10.1%.

A. Regardless of whether the Commission approves or denies BGE's request for a performance adder, BGE would continue to evaluate its metrics under the same metrics or other metrics that the Company determined to be appropriate.

B. Investors expect the Commission to award a return on equity that provides BGE with the opportunity to earn a reasonable return.

C. No. The Company is committed to providing quality service to its electric and gas customers.

D. BGE agrees that managing costs could impact its *earned* return on equity. However, the Company's earned return on equity will be impacted by the return on equity awarded by the Commission.

E. A utility's performance – good or bad – is not an input used in any of the models commonly used for determining the appropriate return on equity. Therefore, to the extent the Commission relies on these models to determine a utility's return on equity, an explicit adder would be necessary to recognize a utility's consistent excellent performance and customer satisfaction.

F. As a matter of policy, the Commission should consider a Company's operational performance when it determines the appropriate return on equity. As noted in the response to subpart E above, none of the commonly used models for determining the appropriate return on equity considers a utility's performance which is why the Company has proposed an adjustment in this case. In the end, the award of a reasonable rate of return will ensure BGE maintains access to capital at a reasonable cost.

G. Under the proposed scenario, there would be no impact during the multi-year plan because the Commission agreed that the ROE and capital structure be set for the duration of the multi-year plan. However, BGE's performance during the multi-year plan period would be appropriately considered when determining the appropriate ROE to award in the Company's next base rate case. Furthermore, the Commission would have other avenues for addressing any decline in the Company's performance such as the annual performance reviews currently undertaken in Case No. 9353 where civil penalties can be assessed for failing to meet the COMAR standards or Commission orders.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 74
Request Received: 07/28/2020
Response Date: 08/07/2020
Sponsor: Ajit Apte

Item No.: StaffDR74-01

Please refer to the Company Staff DR 55-02.

a. Explain if the budgeted amounts presented in the MYP are net of CIAC?

b. (Confidential) the Company indicated that the developer decided to indefinitely defer projects with ID numbers, 53894, 54224, 53888, and 54220. Why are projects 54224, 53894 still in this MYP? Please discuss.

RESPONSE:

a. The budgeted amounts in the projects itemized in the response to StaffDR55-02 response do not include any customer contributions. The projects within this response are all within the Capacity Expansion Distribution investment category and are required to address potential planning violations. As discussed in the response to StaffDR65-15, work to extend new electric services to customer locations are included in new business projects, which do have customer contributions applied.

b. The MYP filing was based on the budget at the time it was filed, which relied on the information we had at the time. To the extent that BGE receives new information, BGE would reflect that updated information in the next budget for 2021-2025. Furthermore, in accordance with Order No. 89482 and as described on pages 20-21 of the Direct Testimony of Company Witness Case and shown on Exhibit MDC-3, annual informational filings for 2021 and 2022 will be filed by April 1 of the next year. In an annual informational filing, to the extent a difference is found to exist between revenues and expenses that would result in a significant amount owed to customers, the Commission can make an adjustment to base distribution rates through the reconciliation riders proposed by Company Witness Fiery.

STATE OF MARYLAND

BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC FOR AN ELECTRIC AND GAS MULTI-YEAR PLAN	Case No. 9645

DIRECT TESTIMONY OF BRENDAN LARKIN-CONNOLLY

Submitted on Behalf of the

Maryland Office of People's Counsel

August 14, 2020

Table of Contents

I. INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is Brendan Larkin-Connolly. I am a Principal at DHInfrastructure LLC. My business address is 9 ½ Market Street, Suite 3B, Northampton, MA 01060.

Q. Please summarize your educational background and professional qualifications.

A. I graduated with a Bachelor of Arts in Economics from College of the Holy Cross in 2007 and I received a Master of Science in Resource Economics from the University of Massachusetts at Amherst in 2009. Upon graduation I started as an analyst at DHInfrastructure where I supported domestic and international projects related to water and energy sector regulation, privatization, renewable energy, and energy efficiency. I subsequently joined the Massachusetts Department of Public Utilities ("DPU") in 2011 as a rates analyst in the Rates and Revenue Requirement Division. Following two years at the DPU, I returned to DHInfrastructure in 2013 as a Manager, and have subsequently been promoted to Principal.

Q. What experience do you have in the area of utility rate setting?

A. As a rates analyst with the Department I was assigned to numerous electric and gas proceedings that required me to provide analytical support on various issues, such as base rates, revenue allocation, decoupling, capital cost recovery trackers, residential assistance adjustment factors, and storm cost recovery.

In my current position at DHInfrastructure, I have advised on utility rate making in both an international and domestic context. Since 2016, I have provided expert consulting services to the Massachusetts Attorney General's Office of Ratepayer Advocacy ("MA-AGO"), Maryland's Office of People's Counsel ("OPC"), and the Illinois Attorney General's Office ("IL-AGO"). My consulting work with the MA-AGO has included advising on six gas system enhancement plan ("GSEP") reconciliation dockets. The GSEP is Massachusetts' version of Maryland's Strategic Infrastructure Development and Enhancement Plan ("STRIDE") program. Like STRIDE, the GSEP is a legislatively mandated leak-prone replacement program with a bifurcated regulatory process that includes submission of annual replacement placement plans for initial approval followed by a reconciliation filing at the end of the construction year for final approval of cost recovery. I have also testified on behalf of the IL-AGO in a reconciliation docket involving the Illinois version of STRIDE, the Qualifying Infrastructure Program ("QIP").

I have worked on utility regulation projects in Kyrgyzstan, Armenia, Mexico, Mongolia, Nauru, Palau, Rwanda, Sierra Leone, Timor-Leste, and Tanzania. In 2018, I prepared a ten-year rate study for the Arusha Urban Water Supply and Sanitation Authority that will be used by local authorities to develop plans for maintaining affordability during a period of high capital investment. In 2016, I advised the Government of Nauru on options for reform of electric and water rates, offering advice on cost of service, rate design, and social protection mechanisms.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes. Attachment BLC-1 is a summary of my qualifications and experience.

Q. Have you previously appeared before the Commission?

A. Yes, I previously testified before the Maryland Public Service Commission (the Commission) on behalf of the OPC on five prior occasions, including Case Number (CN) 9468, Baltimore Gas & Electric's ("BGE" or the Company) request for approval of its second STRIDE plan ("STRIDE 2"). In addition, I submitted testimony in CNs 9479 and 9486, requests from Columbia Gas of Maryland ("CMD") and Washington Gas Light ("WGL"), respectively, for approval of their second STRIDE plans and the associated cost recovery mechanisms. I also testified on behalf of OPC on the issues of rate design and cost of service in CMD's 2018 request for adjustment to base rates, CN 9480. Most recently, I submitted testimony on the STRIDE capital additions being proposed for transfer to rate base in WGL's 2019 request for adjustment to base rates, CN 9605.

Q. Have you previously testified in regulatory proceedings at other agencies?

A. Yes. I have submitted testimony to the Massachusetts DPU on behalf of the Massachusetts AGO and to the Illinois Commerce Commission on behalf of the Illinois Attorney General's Office.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I have been asked by OPC to review the gas capital additions being proposed by BGE in its multi-year rate plan ("MRP"). This review includes both the actual plant additions made through the end of the 2019 historic test year ("HTY"), the budgeted

2020 bridge year ("bridge") additions, and the three-year budgeted additions that make up the MRP. The plant categories covered in my testimony includes six gas-only capital categories and eight common categories where project costs are shared with BGE's electric division.

Q. How is your testimony organized?

A. I begin the substantive part of my testimony, in Section III, by summarizing how BGE has presented the capital additions being proposed for the MRP and outline my approach for evaluating the proposed capital budgets. Then, in the next three sections, I have divided the categories I reviewed into three groups: STRIDE (Section IV), Non-STRIDE gas capital categories (Section V), and common capital categories (Section VI). Within these sections I discuss my findings and recommendations on various projects being proposed for the MRP. Next, in Section VII, I discuss why any budget contingency amounts should not be included in the MRP. Finally, in Section VIII, I offer a conclusion.

Q. Please summarize your findings.

A. I reviewed the historic test year, bridge year, and future test year capital additions being included in the rate base of the three future test years used in BGE's MRP. I have identified several issues with the project budgets that will be addressed in detail in this testimony:

- BGE is attempting to circumvent ratepayer protections included in the STRIDE surcharge by including budgeted STRIDE additions in the MRP rate base
- BGE is also planning to override the 48 mile per year replacement rate approved by the Commission for STIRDE 2 by recovering the cost of replacing additional STRIDE-eligible main through the MRP base rates
- Budgets for several gas and common projects are outside the historic test year (HTY) level without support for the increase in planned expenditures
- BGE has included "plug" or placeholder projects to house budgets for work it has not yet identified
- Contingency amounts have been included in the budgets of several projects and would be reflected in proposed MRP base rates.

Q. Do you recommend any adjustments based on these findings?

A. My review of the gas and common capital additions proposed by BGE for the MRP has identified $854.8 million in capital budgets that I am recommending be removed from the MRP. This includes reductions in gas plant additions of $196.0 million in 2021, $221.2 million in 2022, and $235.8 million in 2023.

The recommended gas plant adjustments also include approximately $610,000 in adjustments to the HTY rate base and $201.2 million in adjustments for the 2020 bridge year. These 2020 adjustments are being recommended because the capital additions being presented in the filing are based on budgets with the same flaws that I have identified for the MRP budgets.

In parallel to certain adjustments I have made to common capital that is shared between gas and electric distribution, there is a total of $119.4 million in MRP capital budget reductions and a $21.8 million reduction to 2020 additions that are flowed through to OPC Witnesses Alvarez and Stephens.

III. <u>MRP GAS CAPITAL ADDITIONS</u>

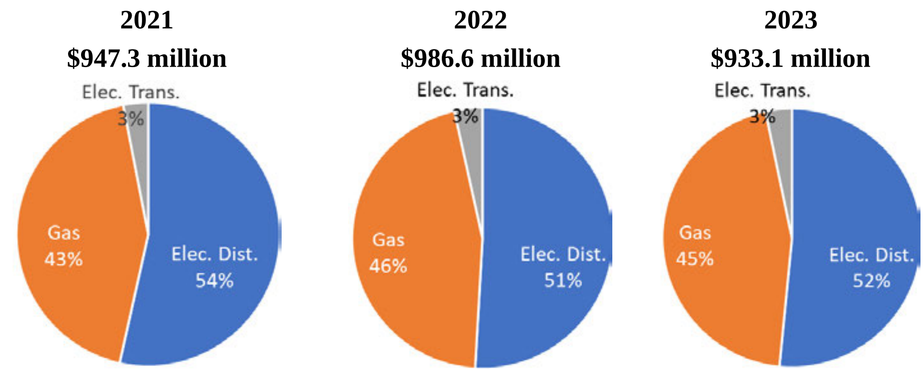
Q. Please summarize the capital additions being proposed in this proceeding.

A. The Company has submitted plans for $2.87 billion in projected capital additions for the MRP.

Q. How are the MRP capital additions allocated by lines of business?

A. The $2.87 billion in capital additions proposed in the MRP includes plant that is directly assigned to the gas distribution ($1.2 billion) and electric ($0.86 billion) distribution business lines; and common (i.e. shared) plant additions ($0.88 billion) that are allocated to gas distribution, electric distribution, and electric transmission. Figure 1 below shows how the capital additions are presented by business line.

Figure 1: MRP Capital Budgets by Business Line

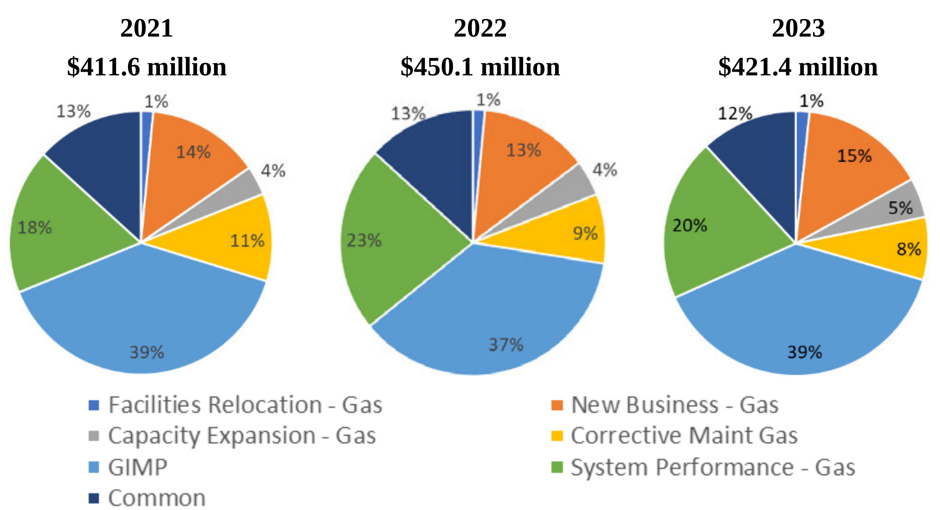


Source: Att. 1 to Staff 41-01

Q. How are the gas capital additions presented in the testimony?

A. BGE divides the gas capital additions, that are the focus of this testimony, into six gas-only categories and then another eight common categories with budgets shared by the Company's three business lines. Figure 2 shows the gas capital budgets are spread across these categories in each of the years in the MRP.

Figure 2: MRP Gas Capital Budgets by Category



Note: Common includes Tools, Customer Operations, BSC, Fleet, IT, Other, Real Estate and Facilities, and Training categories.
Source: Att. 1 to Staff 41-01

Q. What information does the Company provide to support the capital budgets being proposed for the MRP?

A. To support its MRP BGE has provided a list of the projected spend for "projects" over $1 million that are planned for the MRP and the total budget amount by category for projects less than $1 million.

Q. Has BGE complied with the project data filing requirements for the pilot MRP set by the Commission in Order No. 89482?

A. Not exactly. In Order No. 89482[1] the Commission specified that for the Pilot MRP the application should include project-level data for the first year and program-level data for each additional year. The Company has not provided a full set of project-level data for the first year of the MRP as required. As I will explain below what BGE is calling "projects" in the filing are not all specific, discrete work activities. Many are higher-level program budgets for all years of the MRP. BGE Witness Case states that the Company will submit a project list for 2021 within 60 days of the order in this proceeding and subsequently will provide project lists each year.[2]

Q. Have you identified any other problems with the capital project budgets presented by the Company in the MRP?

A. Yes. What the Company is referring to as budgets for projects greater than $1 million in the filing is really a mix of two different categories of budgets:

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[1] Order No. 89482 at pp. 23-24.
[2] BGE Witness Case's Initial Testimony at pp. 20-21

- Discrete projects – projects with discrete activities, location, and/or schedules.
- Program projects – budgets for a general category of project activities without specifics on location or the plant that will be in service.

The issue I have with budgets being proposed for what I'm calling "program" projects is that many of the budget amounts are overly speculative and not based on actual identified work. In many cases, the program budgets for 2020 to 2023 significantly exceed the actual spend in the 2019 HTY. In other cases, the project simply appears to be a "plug" or placeholder to house a budget amount the Company wishes to include in the MRP.

Q. Can you elaborate more on these placeholder type programs?

A. Yes. There are some projects included in the MRP that are new to BGE, i.e. without any historic spend, and are included to represent the budget for work that has not yet been identified. The Company is rather explicit that the budget amounts for these projects are not based on any known work. For example, under the Information Technology (IT) category that will be covered in Section VI, there is a Project 66379: IT Projects where the project description reads, "This project holds the baseline funding for the yet to be designed IT projects."[3]

Q. What is your specific concern with the inclusion of budgets for work not yet identified in the MRP revenue requirement?

[3] Exhibit DMV-8 at p. 10

A. While specific projects and budgets for some activities may not yet be known, accepting budgets with no firm basis in historical spend or identified work could create an incentive structure that promotes over investment. Under the MRP rules there will be a "consolidated reconciliation" after the conclusion of rate year 2 (2022) and then a "final reconciliation" after the conclusion of rate year 3 (2023).[4] If BGE does not spend its fully projected capital budgets set in this proceeding it may need to reimburse customers at the end of the MRP. Therefore, capital budgets used for rate base in the MRP will inevitably be de facto spend targets. This incentive structure could lead to projects being pursued in the MRP for the specific purpose of meeting the budgeted amounts.

Beyond these practical implications of setting rates based on unsubstantiated, non-discrete capital budgets, it is also my conclusion that the budgeting approach used by the Company for its MRP undermines one of the foundational reasons the Commission selected MRP over other alternative ratemaking options.

Q. Please identify how the budgeting approach used by the Company does not meet the terms of Order No. 89226.

A. In Order No. 89226, the Commission made the determination that among five forms of alternative ratemaking considered under Public Conference 51 ("PC51") that a multi-

[4] Order No. 89482 at p. 27

year rate plan based on a historic test year with up to three future test years was the option that would most readily result in just and reasonable rates.[5]

When the Commission made the decision to support the use of an MRP it made clear that it found the submission of both an HTY and MRP future test years as potentially beneficial to understanding the budgeted costs that MRP base rates would be set on. As part of the explanation for its decision to support an MRP, the Commission notes, "A key element of an MRP is that it provides more transparency into a utility's planning process. An MRP will require significant detail into utility planning that is not available to interested parties today."[6]

My understanding of this explanation from the Commission for selecting the use of an MRP is that it expected there would be granular detail within the future test year plans that identify the purpose and need for all capital additions being proposed outside the HTY. That is to say, the "significant detail" on the changes from the HTY to the future test year would provide the "transparency into the utility planning process" that the Commission identified as an advantage of the MRP regulatory process.

Q. And it is your conclusion that the Company has not provided the detail needed to substantiate the capital budgets proposed in its MRP?

[5] Order No. 89226 at pp. 52-55
[6] Order No. 89226 at p. 54

A. Correct. While there are some project budgets that are supported, I find that many of the high-level, program budgets put forward by the Company do not provide the level of detail the Commission was expecting when it approved the use of an MRP.

Q. What approach do you recommend be used to evaluate the capital budgets being proposed for inclusion in the MRP rate base?

A. I have focused my recommended evaluation approach around the two different project types I identified above: discrete projects and program projects. The discrete projects, by definition, have specifics on the work that is planned for the MRP. These can be evaluated on the merits of the project details. Many of the program projects, however, lack these specifics on the activities that will be carried out under the MRP and require further scrutinization.

I recommend that only budget amounts that are for specific, identified work or program budgets that are close to HTY levels be permitted for inclusion in the MRP future test year rate base. This approach is based on the emphasis the Commission made, in Order No. 89226, on the importance of the interplay between the HTY and future test years and an expectation that detailed information would be provided. Specifically, I recommend that to be included in the future test year rate base, capital additions must fit into one of the following groups:

- A discrete project with a clear scope of work;
- A program project with MRP budgets that align closely with historical spend;

- A program project with budgets outside of historical spend and a clear justification for the increase;
- A new program project with a proposed set of work or activities that is shown to be necessary and not covered under another project.

I recommend that for any existing project without sufficient details to support the budget, the MRP budget amount should be reduced to an amount on par with the HTY levels. Any new project without sufficient support should be removed from the MRP. I employ this framework in my evaluation of gas capital and common capital additions in Sections V and VI.

IV. STRIDE IN MRP

Q. How are STRIDE projects reflected in the Company's MRP filing?

All STRIDE work is included in the MRP under the Gas Infrastructure Modernization Program ("GIMP") capital category supported by BGE Witness Burton.[7] Table 1 below shows the budgets for the STRIDE work being completed across three GIMP projects. The budget amounts in the table are roughly equivalent to the $486 million in budgeted costs approved by the Commission for 2020 to 2023 under BGE's second five-year STRIDE plan ("STRIDE 2") in CN 9468.[8]

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[7] BGE response to OPC 7-10.
[8] BGE response to Staff 14-06

Table 1: STRIDE Budget in MRP (million $)

	Bridge	MRP		
Item	**2020**	**2021**	**2022**	**2023**
60522: Leaks - 3/4 Reactive Renewals STRIDE	$6.46	$4.14	$3.28	$1.54
60677: BGE Operation Pipeline	$120.35	$120.69	$122.04	$126.83
61528: Proactive 3/4 Service Renewal Program	$32.87	$36.43	$39.53	$35.02
Total GIMP/STRIDE	**$159.68**	**$161.26**	**$164.85**	**$163.39**

These budgeted STRIDE capital costs in the GIMP category are reflected in the MRP revenue requirements. According to BGE Witness Vahos, "[T]he 2021-2023 budget underlying the MRP revenue requirement calculations includes budgeted STRIDE surcharge revenues, rate base, and related expenses such as depreciation and property taxes."[9] To ensure that costs to be recovered through the STRIDE surcharge are not also recovered through base rates the Company offsets the STRIDE costs in the MRP revenue requirement by including the STRIDE surcharge revenue in the Sale of Gas in operating revenue for each year of the MRP.[10]

Q. Do you have any problems with BGE's treatment of STRIDE in the MRP?

A. Yes. I find the approach to include the projected STRIDE spend in the MRP rate base an attempt by the Company to circumvent the ratepayer protections put in place on the STRIDE surcharge.

Q. Please describe the rate payer protections in the STRIDE surcharge.

[9] BGE witness Vahos' Initial Testimony at p. 34
[10] BGE responses to Staff 47-28 and OPC 19-2.

A. The STRIDE surcharge is a monthly fixed charge adopted in response to the enactment by the Maryland General Assembly of Section 4-210 of the Public Utilities Article, *Annotated Code of Maryland* (Section 4-210 or STRIDE statute). The STRIDE statute authorizes Maryland gas utility companies to file infrastructure investment plans and corresponding project cost-recovery schedules to the Commission for approval. The statue specifies that cost-recovery schedules should be based on estimated project costs to be collected at the same time the eligible infrastructure is installed. Section 4-210(d)(3)(iii) defines the rate mechanism to be used to recover eligible costs as a fixed annual surcharge that is to be capped at $2 each month for residential customers and for all non-residential customers a cap set proportional to each class's total distribution revenues, as determined in the most recent base rate proceeding.

The cap is effectively a limit on the revenue requirement to be collected through the STRIDE surcharge. What happens is that in between base rate adjustments, as the amount of capital additions recovered through the STRIDE surcharge grows, the revenue requirement to be collected through the surcharge also increases, and, in turn, the STRIDE surcharges are increased to collect the higher revenue requirements. Eventually, however, the surcharge cap limits the amount of revenue that can be collected. Once this limit is reached then the Company does not recover its full STRIDE revenue requirement each year.

Q. Can you elaborate on how the approach taken by the Company circumvents the STRIDE surcharge cap?

A. Yes, BGE is bypassing the surcharge by embedding the entire amount of budgeted plant additions that will be carried out under the STRIDE program from 2021 to 2023 in the MRP rate base such that these costs are in the MRP revenue requirement. While BGE nets out the projected revenue that it will receive through the STRIDE surcharge from the MRP revenue requirement, any STRIDE revenue requirement amounts above the projected STRIDE revenue, i.e. any capped revenue amounts, are left over and recovered through the MRP base rates. This result is shown in Table 2 below as the difference between the amount of STRIDE revenue requirement in the MRP (Line 1) and the STRIDE surcharge revenue projections used as the offset amount (Line 2).

Table 2: STRIDE Revenue Collected in MRP Base Rates (million $)

Line	Item	2021	2022	2023
(1)	STRIDE Revenue Requirement in MRP (Staff 60-14 Atts. 4-6)	$7.69	$24.13	$40.35
(2)	STRIDE Revenue excluded from MRP revenue requirement (Staff 33-4 Att. 1)	$7.50	$23.20	$23.40
(3)	STRIDE Revenue Requirement in MRP Base Rates	$0.19	$0.93	$16.95

Note: Line 3 = Line 2 – Line 1

There are two factors contributing to the amount of STRIDE revenue requirement recovered through base rates (Table 2, Line 3). Primarily, starting in 2022 and increasing in 2023, it is the STRIDE surcharge cap. Another factor is that BGE projects the STRIDE revenue offset amount based on its current return on capital approved in BGE's prior rate case, CN 9610, while the revenue requirement on STRIDE investments in the MRP is calculated using the proposed rate of return in this proceeding.[11] This explains why there is $190,000 in STRIDE costs being recovered

[11] BGE response to Staff 60-14.

through the MRP in 2021, a year when the STRIDE surcharge is expected to be uncapped.

Q. Was it the intent of the Company to bypass the STRIDE surcharge cap?

A. Yes, this is not merely speculation. BGE has explicitly stated that its intention is to recover capped STRIDE related revenues requirement through MRP base rates. In response to a discovery question from Staff, BGE states the following:

> *The STRIDE surcharge revenues included in operating income do not completely offset the revenue requirement associated with the STRIDE investments in 2022 and 2023 due to the cap on the STRIDE surcharge revenues. To the extent the capped STRIDE surcharge revenues in 2022 and 2023 do not fully recover the STRIDE-related MRP revenue requirement due to the operation of the cap, the Company is requesting that the revenue requirement above the STRIDE surcharge cap be included in the MRP revenue requirements and the resulting distribution base rates approved by the Commission in this proceeding.*[12]

The Company contends its decision to continue STRIDE in the MRP reflects the directive from the Commission in Order No. 89482 that STRIDE could continue under an MRP.

[12] BGE response to Staff 60-14

Q. The STRIDE capital budgets that are proposed to be recovered through base rates are part of a five-year plan approved by the Commission. Why do you take issue with Company recovering these costs through base rates?

A. Given that the budgets in question are part of a Commission approved plan, I recognize this is a logical question to ask. It is also not lost on me that the Commission found that the continuation of STRIDE under an MRP was possibly beneficial. Before I respond to the question, I should make clear that I do not dispute that this STRIDE work needs to be done and am not trying to restrict the approved STRIDE activities.

To understand why I am raising this issue, it is important to recognize that when the Company put together this filing it had several options for how to operate STRIDE under an MRP. The Company chose the most utility friendly approach, and one that appears inconsistent with the STRIDE statute's key consumer protection. Therefore, I find it important that this issue be raised in this pilot MRP proceeding.

Q. Why might the approach used by the Company not be permitted under the STRIDE statute?

A. As I discussed earlier, the STRIDE statute sets a surcharge cap that limits the revenue that can be collected. Other parts of the statute cast further doubt on the Company's proposal to recover capped costs outside of STRIDE through base rates. Section 4-210(g)(1)(ii)(A) specifies that in a base rate proceeding "eligible infrastructure project costs included in base rates in accordance with a final Commission order on the base rate case shall be removed from a surcharge." I am not a lawyer, so I cannot make a definitive determination, but my plain reading of this part of the statute is that STRIDE project costs cannot be included in both the surcharge and base rates at the same time. If this reading is correct, BGE's proposal to both include all budgeted STRIDE work in the MRP rate base and the STRIDE surcharge would be against state law.

Q. What other options did the Company have to recover the costs of STRIDE work under the MRP?

A. An obvious option was to propose to end its STRIDE surcharge and recover all approved STRIDE costs through base rates. The Commission found that "STRIDE is defined in statute and therefore [it] cannot restrict a utility from filing for a STRIDE surcharge."[13] This did not preclude the Company from making a decision to retire its STRIDE program or choose another alternative approach that would not circumvent the surcharge cap.

Q. What are the other approaches the Company could have taken to continue its STRIDE program?

A. BGE could have kept STRIDE out of base rates until its next base rate/MRP proceeding or the offset could been set at the full STRIDE revenue requirement amount instead of the capped STRIDE revenue amount. Both approaches would have resulted in the Company only earning revenue up to the STRIDE cap.

[13] Order No. 89482 at p. 32

Q. What are the benefits to BGE of keeping the STRIDE surcharge in place under an MRP?

A. This is another reasonable question to consider when trying to understand why the Company would not have simply chosen to retire the STRIDE surcharge.

The STRIDE surcharge can provide the Company with a revenue stream that more closely reflects the costs incurred and permits a faster reconciliation of costs than recovery through MRP base rates alone. This result is because the STRIDE surcharge is reset annually to account for the recovery of budgeted costs for the list of projects planned for the upcoming year. Then, in March each year, the STRIDE surcharge revenue earned from the prior year is reconciled against the actual program costs for the year. This is beneficial to BGE when there are changes in a year that result in higher project costs than expected, such as in 2019 when STRIDE spend was $10.1 million higher partly due to new work hour restrictions in Baltimore.[14] BGE is recovering these additional costs from their customers in 2020, just one year later.

According to the plans outlined for the MRP, any discrepancies between actual costs and revenues received for the first two years of the MRP will not be reconciled until after the second year of the MRP. Inevitably, for 2021 costs, this could result in costs not being reconciled for two years.

[14] Projected 2019 STRIDE spend in BGE's 2018 December 2018 Project List filing was $154.9 million. Actual 2019 STRIDE spend was $165 million. (CN 9468, Exhibit A to BGE's 2019 STRIDE Annual Report submitted on March 23, 2020)

The major drawback to STRIDE recovery, from a utility perspective, is that there is a cap on the surcharge.

Q. What is your recommendation regarding STRIDE in the MRP?

A. In light of the questions I have highlighted surrounding the legality of the proposed approach, I recommend that the Commission require the Company to remove all projected STRIDE plant additions from the MRP. This includes the plant additions reflected in the GIMP categories for 2020, 2021, 2022, and 2023. Recovery of STRIDE projects made in these years will still be permitted through the STRIDE surcharge up to the surcharge cap.

Ultimately, another option for the Commission is to close BGE's STRIDE program and permit the Company to recover these replacement costs through base rates. The argument in favor of this step is that the decision to continue STRIDE was made prior to the Commission's approval of a pilot MRP. We now know that the effect of a utility embedding STRIDE additions in a MRP rate base permits a company to bypass the surcharge caps. I am not recommending this option because I find that the STRIDE regulatory process provides the Commission and stakeholders with valuable insight into the Company's progress replacing leak-prone, higher risk, mains and services. Elimination of STRIDE would, conceivably, put an end to these regulatory requirements for BGE.

Q. Why are you including the bridge year, 2020, in this recommendation?

A. I recognize that it has been customary at the Commission to permit post-test year safety and reliability plant additions, including STRIDE, up through the hearing dates to be rolled into base rates. However, to my knowledge there is no proposal from the Company to update this filing with actual expenses through a certain date. Therefore, given that the STRIDE additions being proposed for 2020 are still only budgeted amounts then my recommendation is that 2020 STRIDE remain in the surcharge until the next base rate proceeding or MRP.

Q. Is any other aspect of BGE's MRP proposal inconsistent with the CN 9468 STRIDE 2 Order?

A. Yes, as I will discuss in the next section, the Company's treatment of STRIDE in the MRP conflicts with the main replacement rates set by the Commission in CN 9468.

V. NON-STRIDE GAS CAPITAL ADDITIONS

Q. What are the non-STRIDE gas capital addition projects you will discuss in this section?

A. The non-STRIDE capital projects reviewed in this section include all capital categories with projects that are directly (100%) assigned to the gas business line. This includes the following gas capital categories: New Business, System Performance, Capacity Expansion, Facilities Relocation, and Corrective Maintenance.

Q. What is the approach you used to evaluate these non-STRIDE gas capital addition project budgets being proposed for the MRP?

A. My approach differed depending on the type of project. Recall, in Section III, I identified that what the Company presents as “projects” greater than $1 million in this proceeding are really a mix of *discrete* projects that include specific details on the planned work and *program* projects with broad descriptions on the general activities that may be pursued under the project over the three-year plan.

Q. How have you evaluated each discrete project?

A. Among the 41 non-STRIDE projects greater than $1 million that are directly assigned by BGE to gas distribution, I labeled 14 of these as discrete projects. These projects are identified in Attachment BLC-2:. I evaluated the work being done on these discrete projects like I would a project being presented in a historic test year. This included reviewing the description and plans for each project in the capital plan documentation provided by each witness and relevant discovery responses to understand the scope of the work and why it is being pursued.

Based on the inspection of the documentation provided on these discrete projects I am not recommending any adjustments to the discrete projects in these non-STRIDE gas capital categories.

Q. What is the approach you used to evaluate the program projects?

A. The approach I employed to evaluate the program projects was developed around the standard I described earlier, in Section III, where I specified that for any capital program project budget to be included in the MRP it should either be close to the historic project spend or have specific and clear explanations for why an increase outside the historical level is needed.

As my first step, I used the 2019 test year costs for each program project as a baseline to evaluate the MRP budgeted spend. Specifically, I compared the average three-year MRP spend for each project to the 2019 test year levels. If the three-year budgeted spend was more than 108% of the test year spend then I made the determination that the budget required further inspection and consideration of an adjustment.

For example, if the historical spend for Project A in 2019 was $5 million and the three-year average budgeted spend was greater than $5.4 million then I would move this project to a second stage evaluation.

Q. What is the significance of the 108% threshold you use?

I chose the 108% threshold because it represents approximately the three-year average if the MRP budgets were the 2019 actual costs adjusted for an annual inflation of 2.5%.[15] This is the same inflation rate BGE applies to various costs items in this proceeding.[16] I determined this rate was appropriate for gas capital additions for two reasons. First, it is commonly accepted that inflation on construction costs rises faster than the general inflation rate as measured by either the Consumer Price Index (CPI) or a GDP deflator. Second, the Company's STRIDE 2 plan that has been approved by

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[15] $(100\% * (1.025)^2 + 100\% * (1.025)^3 + 100\% * (1.025)^4)/3 = 107.77\%$
[16] BGE response to OPC 12-17

the Commission used a 2.5% inflation rate to develop the five-year budgets in the plan.

Q. Why are you using 2019 as the basis of your evaluation of the MRP additions?

A. I am following the Company's own suggestion that the 2019 historic test year costs are to serve at the baseline from which MRP budgeted spend is to be evaluated in this proceeding. The Company emphasizes numerous times in discovery responses that it believes the Commission, in Order No. 89482, established that the 2019 historic test year serves to provide a baseline for the reasonableness of the budgeted spend in the MRP.[17]

Q. What is the next step in your evaluation approach after you have identified a project exceeds the 108% threshold?

A. If a program project is below the 108% threshold, then my determination is that the budget is supported by the record because it is in line with historic program spend. For program project budgets that exceed this threshold, I review the other information provided on the project in discovery or in the Company's testimony to identify if there is evidence in the record that supports the increase in budget.

Then, if I am not able to identify clear support for the increase in the budget, I recommend an adjustment to the MRP project budgets. In most instances, the

[17] BGE response to Staff 23-10

recommended adjustment is to set the project budgets at amounts commensurate with the 2019 HTY levels adjusted for inflation.

Q. How did you treat projects that were not in the 2019 HTY?

A. For the new projects, I relied only on the evidence in the record to evaluate if there was support for the project budget to be included in the MRP.

Several of these new projects appear to be the "plug" or budget placeholder projects, meaning that the Company has created a project entry to house a budget amount to be incorporated into the MRP. It is my conclusion that these types of projects do not meet the expectations laid out by the Commission in Order No. 89226 that the support for the future test years in an MRP would provide more transparency into a utility's planning process. Therefore, any project identified as a budget placeholder is removed from the MRP.

Q. Have you included the budget amounts for projects less than $1 million in your review?

A. Yes. I have treated the budget amounts for projects less than $1 million as single projects within each category. Based on my review of the records I am not aware of anywhere in the docket where the Company has identified the budgets for projects less than $1 million in 2019 and 2020. Therefore, to conduct this analysis I compared the capital budget categories to the sum of the projects greater than $1 million for each category to derive the spend/budget on projects less than $1 million in these years. These results are provided in Attachment BLC-3:

Q. Before you proceed to discussing the different non-STRIDE gas capital categories, are there any where you are not proposing any adjustments?

A. Yes. I am not proposing adjustments to either the Facilities Relocation – Gas or the Corrective Maintenance – Gas categories. I have adjustments for the New Business, System Performance and Capacity Expansion gas categories that will be discussed below.

A. New Business – Gas

Q. Please identify the New Business – Gas projects that you are evaluating in this sub-section.

A. BGE Witness Biagiotti presents ten projects in the New Business – Gas category that I identify as program projects. This category of spend also includes $349,768 in projects less than $1 million. Table 3 shows how the average three-year MRP budget for these New Business – Gas projects compare to the 2019 HTY costs.

Table 3: MRP New Business Gas Program Projects (million $)

	HTY	Bridge	MRP				
Project	2019	2020	2021	2022	2023	3-Year Average	% of 2019 costs
60779: CORE Gas Baltimore City Removals	$1.69	$1.00	$1.03	$1.05	$1.08	$1.05	62%
60780: New Business Gas Residential Changes	$12.76	$8.99	$9.33	$9.94	$10.43	$9.90	78%
60781: New Business Gas Commercial and Industrial Change /Relocation Small Medium	$3.33	$3.02	$3.22	$3.28	$3.45	$3.32	100%
60782: New Business Gas Residential New	$18.38	$18.68	$19.63	$20.62	$22.22	$20.82	113%

Project	HTY 2019	Bridge 2020	MRP 2021	2022	2023	3-Year Average	% of 2019 costs
60783: New Business Gas Commercial and Industrial Conversion	$1.23	$6.26	$3.36	$3.92	$4.62	$3.97	321%
60784: New Business Gas Residential Conversion	$5.93	$7.19	$8.25	$8.88	$9.84	$8.99	152%
60788: New Business Gas Commercial and Industrial New Large	$2.69	$1.94	$2.57	$2.79	$2.78	$2.71	101%
60789: New Business Gas Commercial and Industrial Change /Relocation Large	$0.41	$0.82	$0.90	$0.91	$1.10	$0.97	239%
60791: New Business Gas Commercial and Industrial New Small Medium	$6.86	$7.11	$7.45	$7.48	$7.71	$7.55	110%
61463: New Business Gas Tradepoint Atlantic	$2.82	$1.25	$0.83	$0.62	$0.70	$0.72	25%
Projects < $1 million	$0.07	$0.07	$0.07	$0.08	$0.08	$0.08	117%

Source: BGE Exhibit RDB-1 at pp. 16-18

Highlighted in yellow in the table are the five (5) New Business – Gas projects that exceed the 108% threshold I am using to identify projects with MRP budget spends outside the 2019 HTY. All these programs involve updates to the gas system to accommodate new customers or changes at existing customer facilities. Because of the similarities I discuss the support for these projects as a group below.

The projects less than $1 million for New Business – Gas exceed the threshold but I am not recommending any adjustments because budgets in question are so small that I found the difference between the MRP and HTY budgets to be immaterial.

Q. Are there known changes outside the 2019 HTY that would explain the increased budget for these New Business – Gas projects?

A. Yes. The Company has included projected increases in capital additions from 2020 to 2023 that it expects, or in the case of 2020 *expected*, to occur to convert new gas customers as part of a new gas expansion policy called Pay It Forward.[18] BGE proposed Pay It Forward in November 2019 through a letter filed to the Commission seeking approval of a revision to the gas extension policy in it General Gas Service Tariff.[19] Under the proposed tariff change, the Company sought to change the economic test in the Gas Extension Policy "by providing an offset to a project's cost where that project can lead to additional customer growth."[20] Specifically, the new policy would allow the Company "to look at the economic test results from the population of previous gas extensions and apply certain excess expected revenues from those projects to the individual extension project being evaluated."[21]

Q. Has the Commission granted approval of Pay It Forward?

A. No. Both Staff and OPC, in comments to the Commission, recommended that the underlying issues in the Pay It Forward proposal required a fully docketed proceeding.[22] On May 28, 2020, the Commission concurred that the proposal required further investigation and opened CN 9646 under which testimony will be received and an evidentiary hearing held.[23] A virtual scheduling conference was convened on June 26, 2020 where it was agreed upon that this matter would be tabled until 2021 when

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[18] BGE response to Staff 22-9
[19] BGE. "Supplement No. 459 to P.S.C. Md. G-9: "Pay It Forward" Gas Extension Charge Modernization." 7 November 2019. ("Pay It Forward Filing Letter")
[20] Pay It Forward Filing Letter at p. 2.
[21] Pay It Forward Filing Letter at p. 2.
[22] Order No. 89562. 28 May 2020. pp. 1-2.
[23] Order No. 89562. 28 May 2020. pp. 3-4.

BGE will file initial direct testimony by February 5, 2021.[24] Reply briefs are due May 28, 2021, meaning that at the earliest, an order on Pay It Forward will likely not be released until the third quarter of 2021.[25]

Q. Following Order No. 89562, has the Company agreed to adjust the bridge year and MRP capital additions to reflect the lack of approval of Pay It Forward?

A. No. BGE maintains that the full $14.0 million budgeted amounts for Pay It Forward reflected in the MRP should remain.[26] This includes budgeted capital additions of $2.0 million in 2020, $3.0 million in 2021, $4.0 million in 2022, and $5.0 million in 2023.[27]

Q. What is your recommendation on how the Pay It Forward budgeted amounts should be treated in this proceeding?

A. I recommend that the entire $14.0 million in Pay It Forward amounts be removed from the MRP, including the amounts in the 2020 bridge year. Inclusion of Pay It Forward in the MRP requires too many speculative assumptions, such as the timing of when the program would be approved or how many, if any, new conversions will occur as a result of the new extension policy. Furthermore, the most speculative assumption, given that testimony on the Pay It Forward has not even been filed, is that the new policy will be approved at all. It is no guarantee that the CN 9464 proceeding will

[24] Order No. 89572. 30 June 2020. p. 3.
[25] Order No. 89572. 30 June 2020. p. 2.
[26] BGE response to OPC 11-8
[27] BGE response to Staff 22-9

demonstrate that Pay It Forward should be approved. Parties, including OPC, have already noted in their detailed comment letters to the Commission that the proposal to adopt a new policy that encourages gas expansion may contradict with Maryland's state policy goals to reduce greenhouse gas emissions (GHGs) and could potentially harm existing captive customers.[28] For these reasons, I propose that any amounts budgeted for Pay It Forward be removed.

Q. Do the Pay It Forward budgets account for the total amount of New Business – Gas project budget amounts you have identified as exceeding the historical baseline?

A. No. As shown in Table 4 below, even after removing the Pay It Forward amounts from the total budget for the five projects under inspection, there is still additional unsupported budget.

Table 4: Unsupported New Business – Gas Budget, after Removing Pay It Forward (million $)

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Budget under Inspection	$40.06	$39.60	$41.81	$45.49
(2)	Pay It Forward Budgets	$2.00	$3.00	$4.00	$5.00
(3)	Budget Net of PIF	$38.06	$36.60	$37.81	$40.49
(4)	Baseline	$33.63	$34.47	$35.34	$36.22
(5)	**Unsupported Budget**	**$4.42**	**$2.13**	**$2.47**	**$4.27**

Notes: Line 1 is the sum of budgets for projects 60782, 60783, 60784, 60789, and 60791; Line 2 from BGE response to Staff 22-9; Line 3 = Line 1 – Line 2; Line 4 is the sum of same projects for 2019 ($32.81 million) increased by 2.5% annually; Line 5 = Line 3 – Line 4

[28] See Maillog Nos. 228491 (OPC Comments) and 229801 (Sierra Club Comments)

Q. Does the Company provide any additional information to support the budget for New Business – Gas projects?

A. Yes. The Company provided what it identified as "high level" estimates for planned spend on six large new business gas projects in 2020 and 2021 through discovery.[29] One of the projects, Trade Point Atlantic, has been assigned its own project number and would not fall under the projects being inspected.[30] The remaining five large projects (UPS, Bainbridge, Port Covington, Middle River Depot, and Merriweather) do not appear to have their own separate project numbers. Therefore, for this evaluation purpose, I assume they will fall under the budgets for the new business programs being evaluated in this sub-section.[31] As a conservative approach, I treated the identified budgets for these larger projects as incremental amounts to the historical baseline numbers to evaluate whether the addition of these project activities demonstrates support for the full budget of the five New Business - Gas program projects under investigation.

Q. What are the results when you apply these assumptions and do you recommend any additional adjustments to the New Business - Gas category?

A. After adding the budgets for the large projects identified by the Company to the 2020 and 2021 baseline amounts (i.e. the "supported" amounts), the unsupported amount for 2020 has been reduced by $3.24 million and the proposed budget for 2021 (less Pay It

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[29] BGE response to Staff 22-15
[30] See Table 3.
[31] Project 60782, 60783, 60784, 60789, and 60791.

Forward) is now fully supported. Because BGE did not provide any additional indicative amounts for large projects in 2022 and 2023, the unsupported numbers for these years have not changed. I am recommending that these remaining unsupported budget numbers in Table 5 be added to the Pay It Forward Adjustments I proposed earlier.

Table 5: Unsupported New Business – Gas Adjusted for Large Projects (million $)

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	$33.63	$34.47	$35.34	$36.22
(2)	*UPS*	$3.00	$2.00		
(3)	*Bainbridge*		$2.00		
(4)	*Middle River Depot*	$0.24	$1.50		
(5)	*Merriweather*		$2.40		
(6)	Max Supported Budget	$36.87	$42.37	$35.34	$36.22
(7)	Budget Net of PIF	$38.06	$36.60	$37.81	$40.49
(8)	**Unsupported Budget**	**$1.18**	-	**$2.47**	**$4.27**

Notes: Line 1 is sum of projects for 2019 ($32.81 million) increased by 2.5% annually; Lines 2 to 5 budgets are high range amounts from Staff 22-15; Line 6 is sum of Lines 1 to 5; Line 7 is from Line 3 of Table 3; if Line 6 < Line 7 then Line 8 = Line 7 – Line 6, if Line 6 > Line 7 then Line 8 = 0.

Note that the "supported' amount for 2021 is well above the budgeted amount in the table because the analysis assumes that all large project budgets are incremental to the baseline amounts. However, some of these budget amounts are likely also represented in the historical baseline. This is why I call it a conservative approach.

Q. Please summarize the adjustments you are proposing to the New Business – Gas category project additions for the MRP.

A. I am recommending that the New Business – Gas category capital budgets be adjusted downward to remove $3.0 million from 2021, $6.47 million from 2022, and $9.27

million from the 2023 project budgets. The MRP adjustments are summarized in Table 6.

Table 6: MRP New Business – Gas Adjustments (million $)

		MRP		
Line	**Item**	**2021**	**2022**	**2023**
(1)	Pay It Forward	-$3.00	-$4.00	-$5.00
(2)	Addition Adjustments	$0.00	-$2.47	-$4.27
(3)	**Total**	**-$3.00**	**-$6.47**	**-$9.27**

Notes: Line 3 = Line 1 + Line 2

Q. Are you also recommending adjustments to the plant additions reflected in the 2020 bridge year?

A. Yes. I am recommending that the New Business – Gas capital additions for 2020 be reduced by $3.18 million. This amount includes $2.0 million budgeted for Pay It Forward and another $1.18 million in additional adjustments for excess budgeted costs above the 2019 HTY levels not supported in the record.

B. System Performance – Gas

Q. Please identify the System Performance – Gas projects that you are evaluating in this sub-section.

A. BGE Witness Burton presents eight projects in the System Performance – Gas category that I identify as program projects. This category of spend also includes $1.25 million in projects less than $1 million for the MRP. Table 7 shows how the average three-year MRP budget for these System Performance – Gas projects compare to the 2019 HTY costs.

Table 7: System Performance – Gas Program Projects (million $)

	HTY	Bridge	MRP				
Project	2019	2020	2021	2022	2023	3-Year Average	% of 2019 costs
58034: Non-STRIDE Corrective Maintenance Gas Main Replacements	$0.40	$11.03	$11.76	$12.06	$15.21	$13.01	3,266%
58194: System Reliability - Gas Distribution	$1.15	$4.60	$4.90	$5.03	$4.98	$4.97	433%
58539: Upgrades for Gas Transmission In-Line Inspection	$0.00	$0.00	$0.00	$0.00	$1.90	$0.63	NEW
60666: Gas Infrastructure Improvements	$31.14	$20.82	$19.31	$19.50	$20.36	$19.72	63%
60685: Plant Major Infrastructure - Gas Asset Replacement Program	$4.71	$7.55	$8.12	$8.35	$8.17	$8.21	175%
61208: Gas Facility Security	$4.47	$13.26	$0.39	$0.39	$2.45	$1.08	24%
61212: Valve Replacement Program	$2.87	$6.48	$4.86	$5.99	$5.62	$5.49	191%
61526: Inactive Service Abandonment Program	$3.04	$1.16	$1.25	$1.32	$1.38	$1.32	43%
Projects < $1 million	$1.08	$0.59	$0.52	$0.53	$0.20	$0.42	39%

Source: Exhibit ACB-1 at pp. 9-13

Highlighted in yellow in the table are four (4) System Performance – Gas projects that exceed the 108% threshold that I am using to identify projects with MRP budget spends outside the 2019 HTY. Another project (585389) is also evaluated here because it is new for the MRP and has no historical basis of comparison. I discuss the support for the budgeted amounts proposed for each of these projects individually below.

Q. What is the Project 58034: Non-STRIDE Corrective Maintenance Gas Main Replacements project?

A. BGE defines Project 58034: Non-STRIDE Gas Main Replacement as larger scale replacement work where cast iron and bare steel main are targeted.[32] In other words, these are STRIDE-eligible main replacement projects completed outside of STRIDE. The budget increase from just $398,317 to an average of $13.0 million in the MRP for this category represents the largest increase for any of the gas capital categories presented in this filing.

Q. Has the Company explained why it needs to complete this work outside of STRIDE?

A. The Company suggests that the work is being completed to "progress [its] long term goals to eliminate cast iron, bare steel, and low pressure infrastructure, but that require greater agility to effectively execute due to complex or unique scope, coordination with critical stakeholders, and/or operational constraints and sequencing outside of the limits of STRIDE."

Q. Do you know what the Company means when it refers to the constraints or limits of STRIDE?

A. BGE does not specify the precise constraints or limits of STRIDE that drive the need for this work. However, based on my familiarity with the Company's STRIDE program, from testifying on behalf of OPC in the proceeding when BGE's STRIDE 2 plan was approved, my assumption is the Company is referring to a mile replacement limit. In CN 9468, BGE sought approval to increase the main replacement rate from

[32] BGE Exhibit ACB-1 at p. 8

48 miles per year in the first five-year STRIDE plan to around 70 miles per year under STRIDE 2.[33] I recommended that the Commission require BGE to maintain the initial five-year replacement rate of 48 miles per year[34] and Staff offered a similar recommendation.[35] The Commission accepted this recommendation and Ordered BGE to proceed with STRIDE 2 at a replacement rate of 48 miles per year.[36]

Q. How does the replacement rate set by the Commission in CN 9468 relate to the Non-STRIDE Gas Corrective Maintenance project?

A. My assumption is that when the Company refers to the constraints or limits of STRIDE, it is directly referring to the replacement rate set by the Commission in CN 9468. In this proceeding, BGE is seeking to circumvent the replacement rate set for STRIDE 2 by recovering the costs of additional STRIDE eligible replacement miles through MRP base rates.

Q. Has BGE substantiated a need to increase replacement of STRIDE eligible main through the MRP?

A. In making the determination to set the STRIDE 2 replacement rate at 48 miles per year, the Commission noted in Order 88714:

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[33] Order No. 88714 at p. 17.
[34] Order No. 88714 at p. 21.
[35] Order No. 88714 at p. 25.
[36] Order No. 88714 at p. 27

> *When we balance the costs of the STRIDE 2 Plan with the extent of improvement in safety and reliability as required by §4-210(e)(3), we find we cannot approve the STRIDE 2 Plan as proposed. Based on the record, we agree with Staff that BGE has not fully substantiated its need to have an increased rate of acceleration for the targeted assets as compared to the current STRIDE Plan.*[37]

One of the pieces of evidence I used in CN 9468 to support my recommendation that the Company did not need to increase its main replacement rate was that the leak rates had fallen on cast iron and bare steel mains over the first three years of the STRIDE program.[38] Now, in this proceeding, the Company highlights the continued drop in leaks on mains as a notable performance achievement. Mr. Burton notes, "[T]he quantity of leak repairs on gas mains has been trending downward, with a 3% decrease between 2018 and 2019 alone. In fact, main leak repairs have decreased every year back to 2016 and are 17% lower than they were at their height in 2014."[39]

The prolonged drop in leaks continues to demonstrate to me that the 48 miles per year being completed through STRIDE is a sufficient pace to maintain the safety and reliability of the Company's distribution system. Therefore, I see no justification to further increase STRIDE eligible main replacements outside of STRIDE in the MRP.

Q. Do you have any concerns about the Company's ability to further increase its replacement of STRIDE eligible materials?

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[37] Order No. 88714 at p. 25.
[38] OPC Witness Larkin-Connolly's Initial Testimony in CN 9468 at p. 16.
[39] BGE response to Staff 22-26

A. Yes. On top of my determination that the Company has not demonstrated a need to further increase its main replacement rate there are challenges that BGE has experienced in completing its STRIDE commitments over the last couple years. These challenges raise questions as to why the Company seeks to increase replacements in STRIDE eligible materials. In CN 9648, while the Commission kept the main replacements at 48 miles per year, it approved further acceleration of Pre-1970 ¾" high-pressure steel services (HP steel services) such that all targeted services be replaced by 2021, five years earlier than the original 2026 goal.[40] In this proceeding, BGE has pushed back this target date and now plans to replace the HP steel services by 2023.[41] The Company has identified a shortage of qualified contractors as one challenge that has slowed down its service replacement rate. [42]

I am concerned that BGE is now proposing to accelerate replacement outside the rate set for one STRIDE category, when it is falling behind the approved replacement rate set on another category.

Q. Are you recommending an adjustment to Project 58034: Non-STRIDE Corrective Maintenance Gas Main Replacements budgets in the MRP?

A. Yes. The proposal to include some $50 million of STRIDE eligible work in the MRP, outside of STRIDE, from 2020 to 2023 is another attempt to circumvent the STRIDE regulatory process and the Commission's Order in CN 9468. While, I acknowledge

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[40] Order No. 88714 at p. 27.
[41] BGE response to OPC 7-13
[42] BGE response to OPC 7-12

that some STRIDE eligible work will need to be replaced as need or issues arise in a given year, I find that the amount budgeted for this work should be commensurate with spend on this program in the 2019 HTY. I have concluded that all budgeted amounts above this level are unsupported by the record in this proceeding. Table 8 presents the unsupported non-STRIDE replacement budget amounts that should be removed from the MRP.

Table 8: Unsupported Project 58034 Budget

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	$0.41	$0.42	$0.43	$0.44
(2)	Budget	$11.03	$11.76	$12.06	$15.21
(3)	**Unsupported**	$10.62	$11.34	$11.63	$14.77

Notes: Line 1 is HTY 2019 spend ($0.40 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1.

Q. Please identify the next Safety Performance project you will discuss.

A. The next project I will discuss is Project 58194: System Reliability – Gas Distribution. Work under this project is described as addressing parts of the gas system that have "single points of failure" such as one-way feed mains or single feed district stations which leave customers vulnerable.[43]

Q. Has the Company explained why the MRP budgeted spend is above the 2019 HTY baseline?

[43] BGE response to Staff 45-19

A. Yes. According to BGE, this program is relatively new; it began in 2019 and was ramped up in 2020.[44] Therefore, the amounts in the MRP are representative of target program spend.

Q. Are you recommending any adjustments to Program 58194: System Reliability – Gas Distribution?

A. No. The work, as described by the Company, represents relevant system reliability activities not carried out under any other program. The explanation of the ramp up in spend from 2019 to 2020 and beyond is consistent with the incremental increases to be expected in the first years of a capital program.

Q. What is the next Safety Performance project you will discuss?

A. The next project I will discuss is Project 58539: Upgrades for Gas Transmission In-Line Inspection. This is a new capital project that will not begin until 2023. BGE does not specify exactly what the work will be under this project. The name suggests it will involve the modification of transmission pipe to enable the use of in-line inspection (ILI) tools.[45] An In-line inspection (ILI) tool, sometimes called a " smart pig", is a large measurement device equipped with sensors and cameras that are sent through pipelines to take measurements and record irregularities, such as cracks or signs of corrosion, in transmission pipelines. In some instances, to use ILI tools,

[44] BGE response to Staff 45-19
[45] BGE Exhibit RCB-1 at p. 10

segments of pipe or transmission components need to be updated to permit the passage of the smart pig to make it "piggable."

Q. Has the Company explained why it needs this new ILI project?

A. The Company implies that the project is in response to increasing requirements from the Pipeline and Hazardous Materials Safety Administration (PHMSA) on inspection of transmission lines. In discovery, BGE notes that it is considering the use of ILI to comply with Title 49 Part 192.710 of the Code of Federal Regulations (CFR).[46] This rule, adopted in October 2019, expands PHMSA's routine inspection requirements beyond high consequent areas (HCAs) to a new category it calls moderate consequence areas (MCAs). ILI is one of the seven eligible assessment methods transmission operators can use to comply with these requirements.

This explanation, however, does not identify what the budget included in the MRP will be used for. This contrasts with the other ILI project in this filing, Project ID 58447: Harbor Crossing - Upgrades for In-Line Inspection, where a segment of pipe that will be addressed is identified. No location is provided for this project.

Q. Are you recommending any adjustments to Program 58194: System Reliability – Gas Distribution?

Yes. I recommend that the entire $1.90 million budgeted for Project 58194 in 2023 be eliminated from the MRP capital budget. Unlike the Harbor Crossing project there is

[46] BGE response to Staff 45-22

no specificity on the location or segment of pipe to be replaced. The fact that expenditure will not begin until 2023 suggests that this is one of the place holder budgets for work that will be determined later that I discussed in the beginning of this section. As I explained earlier, I am removing all projects that are acting like budget placeholders for unidentified work.

Q. What is the next Safety Performance – Gas project you will discuss?

A. 60685: Plant Major Infrastructure - Gas Asset Replacement Program. The work under this project includes replacement of various distribution automation and control assets at the LNG and North Cliff propane air production plants.

Q. Has the Company explained why Project 60685 MRP spend is above the 2019 HTY baseline?

A. BGE has indicated that the increase in spend for these activities is due to a new project initiative under this program that focuses on replacing certain logic controllers that have become obsolete and are no longer supported by the manufacturer.[47]

Q. Are you recommending any adjustments to Project 60685: Plant Major Infrastructure – Gas Asset Replacement Program?

Yes. While I do find the explanation that implementing a new project to replace an obsolete set of components is a possible explanation for an increase in program spend, BGE fails to provide any concrete details on this new project. The Company has not

[47] BGE response to Staff 45-26

identified the planned duration or the specific cost of the new work requiring the increased budget. Absent this information it is not possible to verify that it is solely the new activities that are driving the increase.

In addition, the budgets for Project 60685 are all around $3 million above the 2019 HTY baseline amounts. If, in fact, this new logic controller replacement project represents the entire $3 million per year amount in additional costs, the Company should have separated this work into its own entry in the exhibits presenting projects greater than $1 million. For these reasons, I recommend that Project 60685 budgets for the MRP be reduced to amounts aligned with the 2019 HTY level. Table 9 presents the Project 60685 budget amounts I find to be unsupported by the record in this proceeding and am recommending be removed.

Table 9: Unsupported Project 60685 Budget

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	$4.82	$4.94	$5.07	$5.19
(2)	Budget	$7.55	$8.12	$8.35	$8.17
(3)	**Unsupported**	$2.73	$3.17	$3.29	$2.97

Notes: Line 1 is HTY 2019 spend ($0.40 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1.

Q. What is the final System Performance – Gas project you will discuss?

A. Project 61212: Valve Replacement Program. This program involves the replacement and installation of valves and other control devices to create redundancy in the over pressurization protection capabilities on BGE's low-pressure system. Average budgeted spend for these activities for the MRP is $5.49 million – $2.62 million above the 2019 HTY spend of $2.87 million.

Q. Has BGE provide an explanation why the budget for the Valve Replacement Program has increased significantly since 2019?

A. The Company indicates that these replacement activities are being driven by a goal to reduce the over pressurization risk on its low-pressure system. BGE notes, "[A]s a result of the incident in Merrimack Valley, Massachusetts, [it] believes it is prudent to begin installing additional overpressurization protection on its low pressure system."[48]

Q. Are you recommending any adjustment to Project 61212: Valve Replacement Program?

A. No. The increased expenditure on these program activities is consistent with my understanding of other increased efforts being made by gas distribution operators across the country to protect against over pressurization events following the tragic event in Massachusetts.

Q. What are the total adjustments you are proposing for the System Performance – Gas category in the MRP?

A. I am recommending that the System Performance – Gas category capital budgets be adjusted downward to remove $14.51 million from 2021, $14.92 million from 2022,

[48] BGE response to Staff 45-31

and $17.75 million from 2023 project budgets. The MRP adjustments are summarized in Table 10.

Table 10: MRP System Performance – Gas Adjustments (million $)

Line	Project	MRP		
		2021	2022	2023
(1)	58034: Non-STRIDE Corrective Maintenance Gas Main Replacements	-$11.34	-$11.63	-$14.77
(2)	58539: Upgrades for Gas Transmission In-Line Inspection	$0.00	$0.00	-$1.90
(3)	60685: Plant Major Infrastructure - Gas Asset Replacement Program	-$3.17	-$3.29	-$2.97
(4)	**Total Adjustments**	**-$14.51**	**-$14.92**	**-$17.75**

Q. Are you also recommending adjustments to the 2020 bridge year for this category?

A. Yes. I am recommending that the System Performance – Gas capital additions for 2020 be reduced by $13.35 million. This amount includes $10.62 million in unsupported budget for Project 58034: Non-STRIDE Corrective Maintenance Gas Main Replacements and another $2.73 in unsupported budgeted costs for Project 60685: Plant Major Infrastructure - Gas Asset Replacement Program.

C. Capacity Expansion

Q. Please identify the Capacity Expansion projects that you are evaluating in this sub-section.

A. As shown in Table 11 the entire Capacity Expansion – Gas category is covered under a single project: 60701: Reinforcement - Gas System Reinforcements. Evident in the table is that this project exceeds the 108% threshold that I am using to identify projects with MRP budget spends outside the 2019 HTY. I will discuss whether the budget above the historic level is supported by the record in this proceeding below.

Table 11: Capacity Expansion – Gas Program Projects (million $)

	HTY	Bridge	MRP				% of
Project	**2019**	**2020**	**2021**	**2022**	**2023**	**3-Year Average**	**2019 costs**
60701: Reinforcement – Gas System Reinforcements	\$10.95	\$20.99	\$14.79	\$19.41	\$20.38	\$18.19	166%

Source: Exhibit RCB-1 at p. 6

Q. What work is being carried out under Project 60701: Reinforcement - Gas System Reinforcements?

A. The work done through this program includes all projects implemented to address areas with inadequate capacity on the gas transmission and distribution systems.[49] According to Mr. Burton, BGE has included all capacity expansion work to ensure system capacity and reliability is matched to design day conditions. The work is driven by both load growth and changes to gas system configuration.[50]

Q. Has the Company identified the specific drivers that require spend to increase from the 2019 HTY levels?

A. Not exactly. The Company maintains that investments in this program fluctuate year-to-year depending on need.[51] BGE implies that the MRP budgets appear high because the 2019 levels were low due to the delay of a "major steel reinforcement project."[52]

[49] Exhibit RCB-1 at p. 6
[50] BGE Witness Burton's initial testimony at p. 18
[51] BGE response to Staff 45-9
[52] *Id.*

The 2020 budget consequently increases because a portion of the delayed work will be pursued in these MRP years. Rather than identify specific projects, for the MRP years, the Company merely notes that it "anticipates similar larger reinforcement projects [like the 2020 project] will be regularly needed as both growth occurs, and STRIDE conversion work continues."[53]

Q. Is there any information on prior year spend on Capacity Expansion that can provide insight into whether 2019 is an outlier like the Company implies?

A. Yes. BGE has reported that it spent $8.7 million in 2017 and $15.0 million in 2018 on gas capacity expansion.[54] The fact that the $10.95 spend in the 2019 HTY is roughly in between the spend of the previous two years leads me to conclude that it is not an outlier year and is reasonable to use as the basis for evaluating the MRP budgets.

Q. What is your recommendation on 60701: Reinforcement – Gas System Reinforcements?

A. The Company has not sufficiently explained how it arrived at the budgets for this project in the MRP years. General statements about anticipated spend and year-to-year fluctuation are not sufficient to support expenditures in 2022 and 2023 that will be almost $10 million above the 2019 HTY level. My recommendation is that the budgets for 2021 to 2023 should be adjusted to align with the 2019 HTY spend as shown in Table 9.

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[53] *Id.*
[54] BGE response to Staff 22-28

Table 12: Unsupported Project 60701 Budget (million $)

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	$11.23	$11.51	$11.79	$12.09
(2)	Budget	$20.99	$14.79	$19.41	$20.38
(3)	**Unsupported**		$3.29	$7.61	$8.29

Notes: Line 1 is HTY 2019 spend ($10.95 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1.

As I show in Table 12, I have not found the 2020 budget to be unsupported. I find the description on the specific work to be pursued in 2020 was sufficient to support the budget.

Q. What are the total adjustments you are proposing for the Capacity Expansion – Gas category in the MRP?

A. I am recommending that the Capacity Expansion – Gas category capital budgets be adjusted downward to remove $3.29 million from 2021, $7.61 million from 2022, and $8.29 million from 2023 project budgets. The MRP adjustments are summarized in Table 13.

Table 13: MRP System Performance – Gas Adjustments (million $)

		MRP		
Line	**Project**	**2021**	**2022**	**2023**
(1)	58034: Non-STRIDE Corrective Maintenance Gas Main Replacements	-$3.29	-$7.61	-$8.29
(2)	**Total Adjustments**	-$3.29	-$7.61	-$8.29

VI. COMMON CAPITAL ADDITIONS

Q. What categories of capital budgets will you review in this section?

A. In this section, I am going to provide my findings and recommended adjustments on the common capital categories covered by BGE Witnesses Vahos, Biagiotti, and Olivier. These categories include: Tools, Business Services Company (BSC), Information Technology (IT), Fleet, Customer Operations, Real Estate and Facilities, and Other.

Most of the projects in these categories are shared by one or more of BGE's three business lines (gas distribution, electric distribution, and electric transmission). A few are assigned directly (100%) to a business line. My testimony focuses on the gas-only projects and the projects shared by gas and electric distribution. OPC Witnesses Alvarez and Stephens cover any adjustments to the electric-only projects in these categories.

At the conclusion of this section, after I address each category, I will provide a summary on how the proposed adjustments should be divided between gas distribution and electric distribution.

Q. Are you using the same evaluation approach on these Common capital categories that you used on the Non-STRIDE gas capital categories?

A. Yes. I use the same evaluation approach in this section. I first identify which projects are made up of discrete activities and which projects are the more general, program projects with unspecified activities. Then, for the program projects, I compare the three-year average MRP budget for each project to the 2019 HTY level and conduct a deep review of any project above the 108% threshold.

Q. Are there any shared common capital categories where you are not proposing any adjustments?

A. Yes. I am not proposing adjustments to either the BSC or Customer Operations categories.

A. Tools

Q. Please identify the Tools projects that you are evaluating in this sub-section.

A. BGE Witness Biagiotti presents three projects in the Tools category. Two of the projects are electric only and one is gas only. This capital category also includes $4.10 million in projects less than $1 million with budgets that are shared by all three business lines. I will cover the gas only project and projects less than $1 million in this section. Table 14 shows how the average three-year MRP budget for these two Tools projects compared to the 2019 HTY costs. Both exceed the 108% threshold.

Table 14: MRP Tool Program Projects (million $)

	HTY	Bridge	MRP			3-Year	% of
Project	2019	2020	2021	2022	2023	Average	2019
60107: Gas Distribution Tools Capital	$0.77	$1.71	$1.75	$1.79	$1.84	$1.79	231%
Projects < $1 million	$1.03	$1.66	$1.27	$1.44	$1.40	$1.37	133%

Source: Exhibit RDB-1 at p. 22

Q. Are you recommending adjustments to both projects highlighted in the table?

A. Yes.

Q. What is your recommendation on Project 60107: Gas Distribution Tools Capital and why are you proposing it?

A. This project includes purchase of tools needed to maintain the gas distribution system.[55] BGE describes the increase in costs from 2019 to 2020 as the result of purchasing tools for new trucks and trainee classes. The Company goes on to suggest that this 2020 budget represents ongoing costs.[56] My problem with this explanation is that it relies on the use of the 2020 budget amount to justify the budget for the MRP – a one-year projected budget is not appropriate to use as the basis for evaluating the reasonableness of a budget for three separate future years. The explanation provided in discovery fails to provide any detail on the purpose or use of the tools that are supposedly driving the increase in costs. Further information was needed to support the $1 million per year increase in this category above the 2019 HTY level. I recommend that the budgets for Gas Distribution Tools be adjusted to align with the historic level as shown in Table 23 below.

Table 15: Unsupported Project 60088 Budget (million $)

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	$0.79	$0.81	$0.83	$0.86
(2)	Budget	$1.71	$1.75	$1.79	$1.84
(3)	**Unsupported**	**$0.91**	**$0.93**	**$0.96**	**$0.98**

Notes: Line 1 is HTY 2019 spend ($0.77 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1

Q. What is your recommended adjustment to the budget for Tool projects less than $1 million?

[55] Exhibit RDB-1 at p. 32
[56] BGE response to Staff 43-46

A. No information is provided on the tools to be purchased under the projects less than $1 million. Without any additional information I conclude that the budget amounts should be set at annual amounts in line with the 2019 HTY levels as shown in Table 16 below.

Table 16: Unsupported Budget for Tool Projects Less Than $1 million (million $)

Line	Item	Bridge 2020	MRP 2021	MRP 2022	MRP 2023
(1)	Baseline	$1.05	$1.08	$1.11	$1.13
(2)	Budget	$1.66	$1.27	$1.44	$1.40
(3)	**Unsupported**	**$0.61**	**$0.19**	**$0.33**	**$0.26**

Notes: Line 1 is HTY 2019 spend ($1.03 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1

Q. What are the total adjustments you are proposing for the Tools category in the MRP?

A. I am recommending that the Tools category capital budgets be adjusted downward to remove $1.12 million from 2021, $1.29 million from 2022, and $1.24 million from 2023 project budgets. The MRP adjustments are summarized in Table 10.

Table 17: MRP System Performance – Gas Adjustments (million $)

Line	Project	MRP 2021	MRP 2022	MRP 2023
(1)	60107: Gas Distribution Tools Capital	-$0.93	-$0.96	-$0.98
(2)	Projects < $1 million	-$0.19	-$0.33	-$0.26
(3)	**Total Adjustments**	**-$1.12**	**-$1.29**	**-$1.24**

Q. Are you also recommending adjustments to the 2020 bridge year for this category?

A. Yes. I am recommending that the Tools capital additions for 2020 be reduced by $1.29 million.

B. IT

Q. Please identify the IT projects that you are evaluating in this sub-section.

A. BGE Witness Vahos presents 29 projects in the IT category that have proposed budgets for the MRP. I will be covering five shared projects that I have identified as program projects. This category of spend also includes $4.10 million in projects less than $1 million whose budgets are shared by all three business lines.

Table 18 shows how the average three-year MRP budget for the six IT projects under consideration compare to the 2019 HTY costs. One of the projects greater than $1 million exceed the 108% threshold I am using to identify projects that require further inspection. The other four are all new for the MRP and were reviewed because they have no historical basis of comparison.

Table 18: MRP IT Program Projects (million $)

	HTY	Bridge	MRP				
Project	**2019**	**2020**	**2021**	**2022**	**2023**	**3-Year Average**	**% of 2019 costs**
64713: EU Digital Program – 2020	$0.00	$1.95	$2.55	$2.64	$4.29	$3.16	NEW
60727: Pass Through - Capital IT	$3.57	$4.90	$4.90	$4.90	$4.90	$4.90	137%
66379: IT Projects	$0.00	-$0.27	$0.00	$20.26	$54.75	$25.00	NEW
64690: BGE PC 44 Rate Pilots	$0.00	$1.02	$1.00	$0.00	$0.00	$0.33	NEW
64692: Supplier Consolidated Billing - Case # 9461	$0.00	$0.48	$2.94	$0.51	$0.00	$1.15	NEW
Projects < $1 million	$10.76	$9.22	$2.83	$1.51	$0.92	$1.75	16%

Source: Exhibit DMV-8 at pp. 6-14

Q. Are you recommending adjustments to all projects highlighted in the table?

A. Yes.

Q. What is your recommended adjustment on the 64713: EU Digital Program – 2020 and why are you proposing it?

A. The description for the work under this project reads as follows:

> *On-going enhancements are expected to grow self-service options, improve proactive outbound communications, and use technology and innovation to reduce customer barriers and meet customers where they are in their daily lives.*[57]

There are no specifics in this description on the work or activities that will be carried out in 2020 or the MRP years for this project. It appears like this project is a budget placeholder for work within the EU Digital Program that will be determined later. I recommend that the entire budget amounts be removed from the MRP.

Q. Next, what is your recommended adjustment to 60727: Pass Through - Capital IT and why are you proposing it?

A. This project includes the cost of computers, servers, and network equipment. The $4.9 million per year budget for 2020 to 2023 is $1.4 million above the 2019 HTY level without any explanation of why costs have increased. I recommend that the budget amounts reflected in the MRP are set in line with the historic level as shown in Table 19 below.

[57] Exhibit DMV-8 at p. 6

Table 19: Unsupported Budget for Project 60727 (million $)

Line	Item	Bridge	MRP		
		2020	2021	2022	2023
(1)	Baseline	$3.65	$3.75	$3.84	$3.94
(2)	Budget	$4.90	$4.90	$4.90	$4.90
(3)	**Unsupported**	**$1.25**	**$1.15**	**$1.06**	**$0.96**

Notes: Line 1 is HTY 2019 spend ($3.57 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1

Q. What is your recommended adjustment to 66379: IT Projects and why are you proposing it?

A. The description of the IT Projects explicitly states that the project "holds the baseline funding for the yet to be designed IT projects." This is the definition of a "plug" or budget placeholder type project. I recommend the entire amounts be eliminated.

Q. What is your recommended adjustment to 64690: BGE PC 44 Rate Pilots project and why are you proposing it?

A. The Company identifies this project as work to implement activities needed in response to rate pilots that come out of Public Conference 44 (PC44). PC44 is an initiative opened by the PSC to specifically investigate matters related to the transformation of the electric distribution system. As I show in Table 22 below the Company has allocated a portion of this capital budget to gas distribution. I assume this is a mistake and recommend that all budget assigned to gas be removed from the gas MRP. I am not adjusting the electric distribution portion of costs.

Table 20: Allocation of Project 64690 Budget by Business Line (million $)

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	**Gas**	**$0.32**	**$0.31**	**$0.00**	**$0.00**
(2)	Electric Distribution	$0.60	$0.59	$0.00	$0.00
(3)	Electric Transmission	$0.10	$0.10	$0.00	$0.00
(4)	Total Budget	$1.02	$0.31	$0.00	$0.00

Source/notes: 2021 to 2023 budgets by business line from Att. 1 to Staff 41-1. $2.25 million 2020 budget is allocated by business line in proportion to budget allocation in 2021 to 2023.

Q. Finally, what is your recommended adjustment to 64692: Supplier Consolidated Billing - Case # 9461 and why are you proposing it?

A. The budget under this project is set aside to address IT issues related to the Order 89116 in Case 9461 that approved third party supplier billing. I acknowledge that there will be costs incurred related to this change. However, the Company notes in its description of the project, "The full requirements are not yet fully realized so the PSC has created a working group to address implementation details." It is not clear what the budget amounts presented here are intended to cover if the details regarding the change are still being determined. If this project was not being driven by a Commission Order, I would recommend eliminating the entire MRP budget because the budget amount is being used here as a placeholder until the actual work is identified. Because, the project is being driven by a Commission requirement I recommend that only 50 percent of the annual budgets be removed.

Q. What are the total adjustments you are proposing for the Tools category in the MRP?

A. I am recommending that the Tools category capital budgets be adjusted downward to remove $5.49 million from 2021, $24.22 million from 2022, and $60.00 million from 2023 project budgets. The MRP adjustments are summarized in Table 21.

Table 21: MRP IT Adjustments (million $)

		MRP		
Line	**Project**	**2021**	**2022**	**2023**
(1)	64713: EU Digital Program - 2020	-$2.55	-$2.64	-$4.29
(2)	60727: Pass Through - Capital IT	-$1.15	-$1.06	-$0.96
(3)	66379: IT Projects	$0.00	-$20.26	-$54.75
(4)	64690: BGE PC 44 Rate Pilots	-$0.31	$0.00	$0.00
(5)	64692: Supplier Consolidated Billing - Case # 9461	-$1.47	-$0.25	$0.00
(6)	**Total Adjustments**	**-$5.49**	**-$24.22**	**-$60.00**

Q. Are you also recommending adjustments to the 2020 bridge year for this category?

A. Yes. I am recommending that the IT capital additions for 2020 be reduced by $3.75 million. This includes $1.25 million for Project 60727: Pass Through – Capital IT; $0.32 million for Project 64690: BGE PC 44 Rate Pilots; $1.95 million for Project 64713: EU Digital Program – 2020; and $0.24 million for Project 64692: Supplier Consolidated Billing - Case # 9461.

C. Fleet

Q. Please identify the Fleet projects that you are evaluating in this sub-section.

A. BGE Witness Vahos presents three projects greater than $1 million in the Fleet category for the MRP. Table 22 shows how the average three-year MRP budget for the Fleet projects compare to the 2019 HTY costs. Two of the projects exceed the 108% threshold I am using to identify projects that require further inspection.

Table 22: MRP Fleet Program Projects (million $)

	HTY	Bridge	MRP				
Project	**2019**	**2020**	**2021**	**2022**	**2023**	**3-Year Average**	**% of 2019 costs**
59820: Lease Buyout - Balloon Payment	$0.16	$1.00	$0.70	$0.40	$0.10	$0.40	**244%**
60088: Fleet Projects	$0.58	$1.28	$1.12	$1.42	$0.59	$1.04	**178%**
60089: Fleet Capital Procurement	$20.33	$26.80	$20.10	$18.80	$17.10	$18.67	92%

Source: Exhibit DMV-8 at p. 16

Q. Are you recommending adjustments to both projects highlighted in the table?

A. No, I am only recommending an adjustment to the 60088: Fleet Projects. The projected budget for the 59820: Lease Buyout roughly aligns with the 60089: Fleet Capital Procurement budget and the fleet planned replacement schedule provided in discovery.[58]

Q. What is your recommendation on 60088: Fleet Projects and why are you proposing it?

A. Fleet Projects include the purchase of shop equipment and mechanic tools used for maintaining the fleet vehicles.[59] There is no explanation provided for why the budget for fleet equipment and tools needs to be above the 2019 HTY from 2020 to 2022. I recommend that the budgets for these years be adjusted to align with the historic level as shown in Table 23 below.

[58] BGE response to Staff 20-21
[59] Exhibit DMV-8 at p. 16

Table 23: Unsupported Project 60088 Budget (million $)

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	$0.60	$0.61	$0.63	$0.64
(2)	Budget	$1.28	$1.12	$1.42	$0.59
(3)	**Unsupported**	**$0.68**	**$0.50**	**$0.79**	--

Notes: Line 1 is HTY 2019 spend ($0.58 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1

Q. What are the total adjustments you are proposing for the Fleet category in the MRP?

A. I am recommending that the Fleet category capital budgets be adjusted downward to remove $0.5 million from the 2021 and $0.79 million from the 2022 MRP capital budgets. The MRP adjustments are summarized in Table 24.

Table 24: MRP System Performance – Gas Adjustments (million $)

		MRP		
Line	**Project**	**2021**	**2022**	**2023**
(1)	60088: Fleet Projects	-$0.50	-$0.79	--
(2)	**Total**	**-$0.50**	**-$0.79**	--

Q. Are you also recommending adjustments to the 2020 bridge year for this category?

A. Yes. I am recommending that the Fleet capital additions for 2020 be reduced by $0.68 million.

D. Real Estate and Facilities

Q. Please identify the Real Estate and Facilities projects that you are evaluating in this sub-section.

A. BGE Witness Vahos presents 17 projects in the Real Estate and Facilities category. Seven projects have budget proposed for the three-year MRP. Four of these seven projects include work activities at specifically identified locations and have been evaluated as discrete projects. I have identified the remaining three projects as being program projects for general, unspecified facilities activities. This category of spend also includes $3.74 million in projects less than $1 million whose budgets are shared by all three business lines.

Table 25 shows how the average three-year MRP budget for the Real Estate and Facilities projects under consideration compare to the 2019 HTY costs. Two of the projects greater than $1 million exceed the 108% threshold I am using to identify projects that require further inspection. The other one is a new project for the MRP and was reviewed because it has no historical basis of comparison.

Table 25: MRP Real Estate and Facilities Program Projects (million $)

	HTY	Bridge	MRP				
Project	**2019**	**2020**	**2021**	**2022**	**2023**	**3-Year Average**	**% of 2019 costs**
60820: Infrastructure - Capital Infrastructure Management Projects	$3.48	$10.39	$9.28	$9.24	$7.88	$8.80	253%
60832: Renovations - Capital Lifecycle Projects	$0.08	$20.84	$20.16	$24.71	$19.70	$21.52	27,023%
66622: Office and Support Facilities Program	$0.00	$0.86	$5.73	$7.57	$7.80	$7.03	NEW
Projects < $1 million	$4.50	$1.82	$1.27	$1.22	$1.24	$1.24	28%

Source: Exhibit DMV-8 at pp. 17-20

Q. Are you recommending adjustments to all three projects highlighted in the table?

A. Yes. I am proposing adjustments to all three programs greater than $1 million.

Q. What is your recommendation on 60820: Infrastructure - Capital Infrastructure Management Projects and why are you proposing an adjustment?

A. Project 60820 is a general facilities program that covers planned and emergent capital improvements or replacements of things such as HVAC, elevators, alarms, motors, chillers, boilers, and paving.[60] No further specifics are provided on this work. The budget amounts here appear to be placeholders for work that has not yet been identified. I am making the case in this testimony that only project budgets that either align with 2019 HYT level or have work specifically identified be included in the MRP revenue requirements. Project 60820 budgeted amounts do not meet this standard and I recommend that the budgets for 2020 to 2023 be adjusted to align with the historic level as shown in Table 26 below.

Table 26: Unsupported Project 60820 Budget

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	\$3.48	\$3.56	\$3.65	\$3.75
(2)	Budget	\$10.39	\$9.28	\$9.24	\$7.88
(3)	**Unsupported**	**\$6.91**	**\$5.71**	**\$5.58**	**\$4.13**

Notes: Line 1 is HTY 2019 spend (\$3.39 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1

Q. Next, what is your recommendation on 60832: Renovations - Capital Lifecycle Projects and why are you proposing adjustment?

A. Similar to the previous project, Project 60832 is a general facilities program. This program covers renovations and replacements of things such as HVAC, lighting, fire

[60] Exhibit DMV-8 at p. 19

systems, and windows.[61] Here too, BGE does not specify any location or indicative plan that the budget was built around. For the same reason, I recommend that the Project 60832 budgets for 2020 to 2023 be adjusted to align with the historic level as shown in Table 27 below.

Table 27: Unsupported Project 60832 Budget

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	$0.08	$0.08	$0.09	$0.09
(2)	Budget	$20.84	$20.16	$24.71	$19.70
(3)	**Unsupported**	**$20.76**	**$20.07**	**$24.62**	**$19.61**

Notes: Line 1 is HTY 2019 spend ($0.0796 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1

Q. Finally, what is your recommendation on 66622: Office and Support Facilities Program and why are you proposing an adjustment?

A. BGE describes Project 66622, or the "OSF" project, as an initiative to increase the security and safety at company office buildings and support facilities over the next eight years. BGE has provided no information or explanation to support the work or the budget that is proposed for the MRP. BGE notes this work will start with a scoping analysis *in 2020*. In other words, the work to be completed under the OSF project had not even been scoped out when the Company submitted these budgets. This raises questions about whether there is actual identified work behind the allotted budget amounts. Therefore, I recommend the entire $21.96 million project be removed from the MRP.

[61] Exhibit DMV-8 at p. 19

Q. What are the total adjustments you are proposing for the Real Estate and Facilities category in the MRP?

A. I am recommending that, in total, the Real Estate and Facilities capital budgets be adjusted downward to remove $31.52 million from 2021, $37.77 million from 2022, and $31.54 million from the 2023 project budgets. The MRP adjustments are summarized in Table 28.

Table 28: MRP Real Estate and Facilities Adjustments (million $)

		MRP		
Line	**Project**	**2021**	**2022**	**2023**
(1)	58034: Non-STRIDE Corrective Maintenance Gas Main Replacements	-$5.71	-$5.58	-$4.13
(2)	58539: Upgrades for Gas Transmission In-Line Inspection	-$20.07	-$24.62	-$19.61
(3)	60685: Plant Major Infrastructure - Gas Asset Replacement Program	-$5.73	-$7.57	-$7.80
(4)	**Total Adjustments**	**-$31.52**	**-$37.77**	**-$31.54**

Q. Are you also recommending adjustments to the 2020 bridge year for this category?

A. Yes. I am recommending that the Real Estate and Facilities category additions for the 2020 bridge year be reduced by $28.53 million. This includes reductions of $6.91 million for Project 60820, $20.76 million for Project 60832, and $0.86 million for Project 66622.

E. Training

Q. Please identify the Training project that you are evaluating in this sub-section.

A. BGE Witness Vahos presents a single project under the Training category for the MRP. Table 29 shows how the average three-year MRP budget for the project compares to the 2019 HTY costs. As evident in the table, the Budget Utility Training Capital project's three-year average budget is above the 108% threshold I am using to identify project budgets that require additional support.

Table 29: MRP Training Program Projects (million $)

Project	HTY	Bridge	MRP			3-Year Average	% of 2019 costs
	2019	2020	2021	2022	2023		
60127: Budget Utility Training Capital	$0.61	$1.50	$1.50	$1.50	$1.50	$1.50	245%

Source: Exhibit DMV-8 at p. 21

Q. Are you recommending adjustments to 60127: Budget Utility Training Capital?

A. Yes. This project involves work to develop training simulations using virtual reality technologies to be used in several of the Company's business lines. According to BGE this work represents an eligible capital activity because it will result in the creation and development of long-term hardware and software that will be used as alternative to cost intensive instructor-led training.[62]

The potential for virtual reality to replace in-person training is an experimental concept that should not be borne by ratepayers. Furthermore, the Company's three-year operating and maintenance (O&M) training budget ($26 million) is nearly identical to the 2019 HTY ($26 million).[63] While, in nominal terms, this may represent a modest drop in training costs it does not suggest a move to virtual reality

[62] BGE response to Staff 51-02
[63] Exhibit DMV-8 at p. 21

training will make any substantial impact on operating expenses during the MRP. For these reasons, I recommend that the entire Project 60127 actual and budgeted amounts be removed from the MRP.

Q. What are the total adjustments you are proposing for Training category in the MRP?

A. I am recommending that the Training category capital budgets be adjusted downward to remove $1.50 million from 2021; $1.50 million from the 2022, and $1.50 million from the 2023 MRP capital budgets. The MRP adjustments are summarized in Table 30.

Table 30: MRP Training Adjustments (million $)

		MRP		
Line	**Project**	**2021**	**2022**	**2023**
(1)	60127: Budget Utility Training Capital	-$1.50	-$1.50	-$1.50
(2)	**Total**	**-$1.50**	**-$1.50**	**-$1.50**

Q. Are you also recommending adjustments to the 2019 HTY and 2020 bridge year for this category?

A. Yes. I am recommending that the $610,445 in 2019 Training capital additions be denied for inclusion in the HTY rate base and the budgeted 2020 Training capital additions be reduced by $1.50 million.

F. Other

Q. Please identify the Other projects that you are evaluating in this sub-section.

A. BGE Witness Vahos presents 14 projects in the Other category. Three of the Other projects are electric-only. Two projects only include 2019 HTY costs and I found three projects have sufficient details on the work to be conducted that I categorized them as discrete projects. I have identified the remaining six projects as being program projects. The Other category also includes $3.74 million in projects less than $1 million shared by all three business lines.

Table 31 shows how the average three-year MRP budget for the Other projects under consideration in this section compare to the 2019 HTY costs. Four of the entries exceed the 108% threshold I am using to identify projects that require further inspection. There are also three projects, for which I did not have a historical comparison, that I also included in this review.

Table 31: MRP Other Program Projects (million $)

	HTY	Bridge	MRP				
Project	**2019**	**2020**	**2021**	**2022**	**2023**	**3-Year Average**	**% of 2019 costs**
55789: PC44 Program - Capital	$0.00	$2.25	$2.59	$1.07	$0.00	$1.22	NEW
60996: Corporate Items Logistics - Topside	$1.60	-$0.70	-$1.72	-$2.80	-$3.74	-$2.75	-172%
61568: Innovation Initiative - Capital	$0.89	$2.00	$2.00	$2.00	$2.05	$2.02	**227%**
53369: Back Office Allocation	$0.51	$22.36	$17.92	$17.52	$16.86	$17.44	**3,428%**
61076: Meter Engineering & Standards Capital	$1.37	$1.34	$1.30	$0.97	$1.00	$1.09	79%
61587: Capital Portion of Compensation	$0.00	$1.71	$1.71	$1.71	$1.71	$1.71	**NEW**
63252: AMI 4.5 Relay Replacement	$0.00	$0.00	$0.00	$2.70	$0.00	$0.90	**NEW**
Projects < $1 million	$1.09	$2.79	$2.67	$1.97	$1.92	$2.19	**201%**

Source: Exhibit DMV-8 at pp. 17-20

Q. Are you recommending adjustments to all projects highlighted in the table?

A. No. I am proposing adjustments to only three of the highlighted projects: 55789: PC44 Program – Capital; 61568: Innovation Initiative – Capital; and Other projects less than $1 million.

I am not making any adjustment to Project 55369 because the Company has stated that these amounts are all transmission costs that are only notionally assigned to gas and electric distribution in their workpapers and are removed from the MRP revenue requirement.[64] I also found the documentation and explanations for the other two new projects (61587 and 63252) to support the budgeted amounts.

Q. What is your recommendation on Project 55789: PC44 Program - Capital and why are you proposing an adjustment?

A. Project 55789 includes investment in equipment or technology related to topics covered under PC44, such as electric vehicle (EV) infrastructure, solar photovoltaics, and energy storage.[65] As I show in Table 32**,** the Company has again allocated a portion of this capital budget to gas distribution. I recommend that all budget assigned to gas be removed from the gas MRP because this is an electric-only proceeding. I am not adjusting the electric distribution portion of costs.

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[64] BGE response to Staff 51-05
[65] Exhibit DMV-8 at p. 22

Table 32: Project 55789 Budget by Business Line (million $)

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	**Gas**	**$0.69**	**$0.80**	**$0.33**	**$0.00**
(2)	Electric Distribution	$1.33	$1.53	$0.63	$0.00
(3)	Electric Transmission	$0.23	$0.26	$0.11	$0.00
(4)	Total Budget	$2.25	$0.80	$0.33	$0.00

Source/notes: 2021 to 2023 budgets by business line from Att. 1 to Staff 41-1. $2.25 million 2020 budget is allocated by business line in proportion to budget allocation in 2021 to 2023.

Q. Next, what is your recommendation on 61568: Innovation Initiative - Capital and why are you proposing an adjustment?

A. Project 61568 includes capital budgets for various capital investments that apparently are made by BGE to test or pilot certain projects that "may have the ability to increase the efficiency, effectiveness, safety, reliability, and/or resiliency of BGE's Operations and BGE customers" prior to proceeding to full-scale deployment. While there may be specific examples of pilot or test projects that are prudent to make prior to full scale deployment, the budgets being presented here are merely place holders for such work that may be identified later and the amounts are not representative of historical spend. I recommend that the Project 61568 budgets for 2020 to 2023 be adjusted to align with the historic level as shown in Table 33 below.

Table 33: Unsupported Project 61568 Budget (million $)

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	$0.91	$0.93	$0.96	$0.98
(2)	Budget	$2.00	$2.00	$2.00	$2.05
(3)	**Unsupported**	**$1.09**	**$1.07**	**$1.04**	**$1.07**

Notes: Line 1 is HTY 2019 spend ($0.89 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1

Q. What is your recommended adjustment to the budget for Other projects less than $1 million?

A. BGE is proposing to double the annual budget for the projects less than $1 million in the MRP. The "Other" category of capital additions is made up of projects that do not fit within other capital categories. Because this is effectively a "catch-all" capital category, the information we have for these projects less than $1 million is even less than in the non-Other categories that have a more defined scope of activities. In other words, this a catch-all budget for the catch-all category. Absent information on why this significant increase is needed, I am recommending that the budgeted amount for Other projects less than $1 million be reduced to baseline levels as shown in Table 34.

Table 34: Unsupported Other Projects Less than $1 million Budget (million $)

		Bridge	MRP		
Line	**Item**	**2020**	**2021**	**2022**	**2023**
(1)	Baseline	$1.12	$1.15	$1.17	$1.20
(2)	Budget	$2.79	$2.67	$1.97	$1.92
(3)	**Unsupported**	**$1.67**	**$1.53**	**$0.80**	**$0.72**

Notes: Line 1 is HTY 2019 spend ($1.09 million) increased by 2.5% annually; Line 3 = Line 2 – Line 1

Q. What are the total adjustments you are proposing for Other category in the MRP?

A. I am recommending that the Other capital budgets be adjusted downward to remove $3.39 million from 2021, $2.17 million from 2022, and $1.79 million from the 2023 project budgets. The MRP adjustments are summarized in Table 35.

Table 35: MRP Other Adjustments (million $)

		MRP		
Line	**Project**	**2021**	**2022**	**2023**
(1)	55789: PC44 Program – Capital	-$0.80	-$0.33	--
(2)	61568: Innovation Initiative – Capital	-$1.07	-$1.04	-$1.07
(3)	Projects < $1 million	-$1.53	-$0.80	-$0.72
(4)	**Total**	**-$3.39**	**-$2.17**	**-$1.79**

Q. Are you also recommending adjustments to the 2020 bridge year for this category?

A. Yes. I am recommending that the Other category project additions for the 2020 bridge year be reduced by $3.45 million. This includes reductions of $0.69 million for Project 55789, $1.09 million for Project 61568, and $1.67 million for projects less than $1 million.

G. Assignment of Common Capital Adjustments

Q. How do you allocate any recommended adjustments to any projects with shared budgets across the gas and electric business lines?

A. I assign any recommended adjustment amounts to each business line in proportion to how BGE has apportioned the budgets for the project in this filing. A worksheet was provided in discovery that breaks out the budget amounts for each project greater than $1 million and project less than $1 million into business lines.[66]

For example, most IT projects are generally assigned 31% to gas distribution, 59% to electric distribution, and 10% to electric transmission. If I recommend a $1 million reduction to the budget for a project in 2021, then $310,000 of the adjustment would be applied to gas distribution and $590,000 would be applied to electric distribution.

I should also note that because I only had project budgets by business line for the three MRP years available to me, and not the 2020 bridge year, if an adjustment is proposed for the bridge year I use an average of the MRP allocation percentages for the project to apportion the adjustment.

Q. Please identify how you have divided the Common capital adjustments.

A. Table 36 below presents how the Common capital adjustments are divided between gas distribution and electric distribution.

Table 36: Common Capital Adjustments by Business Line (million $)

		HTY	Bridge	MRP		
Line	**Category**	**2019**	**2020**	**2021**	**2022**	**2023**
(1)	Electric Distribution Adjustments	0	-$21.84	-$24.32	-$39.07	-$56.00
(2)	Gas Distribution Adjustments	-$0.61	-$17.58	-$12.84	-$23.27	-$37.09
(3)	**Total Common Plant Adjustments**	**-$0.61**	**-$39.43**	**-$37.16**	**-$62.34**	**-$93.09**

[66] Attachment 1 to Staff 41-01

I have provided all recommended adjustments for electric distribution to OPC Witnesses Alvarez and Stephens to include in their proposed adjustments to the MRP electric distribution capital budgets.

VII. CONTINGENCY

Q. Has the Company included any contingency amounts in the gas capital budgets being proposed for the MRP?

A. Yes, the Company includes contingency amounts in the capital budgets for some large gas capital and IT projects in the MRP.[67] BGE states that it determines the contingency amounts needed on a project by project basis based on the discretion of project managers.[68]

Q. Are you aware of any guidance the Commission has provided on the inclusion of contingencies in budgeted costs that will be recovered from ratepayers?

A. Yes. In CN 9486, WGL's request for its second five-year STRIDE plan, the Commission ordered WGL to remove contingency amounts it had proposed to be included in the STRIDE project costs that would be used to set the annual STRIDE surcharge. The Commission made this decision in response to a recommendation I had made that WGL's plan to include contingency in the budgeted costs used to set the surcharge would be inappropriate.

[67] See Att. 1 to Staff 66-02
[68] BGE response to Staff 20-22.

Q. Why did you recommend that contingency amounts not be permitted for inclusion in the STRIDE budgets?

A. Contingency is an amount included in a project budget to cover unknown or unanticipated project costs. From a financial planning and project management respect, including a contingency is a reasonable precaution to take to ensure that there are sufficient funds available to cover project costs. My concern in the WGL STRIDE proceeding was that by including contingency costs into the project budgets that are used to set the annual STRIDE surcharge you are asking customers to pay for this contingency amount upfront before a company has even identified a need for it. My conclusion in that proceeding was that, "[s]hould a project incur unforeseen costs that causes cost overruns, I find that rather than build some contingency into the estimate to account for these costs upfront then it is more appropriate to wait until the reconciliation stage of STRIDE so that the Commission can evaluate the cost driving the variance and determine if it is a prudent expense."[69]

Q. Are you recommending that contingencies be removed from the MRP plan?

A. Yes. The proposal to include contingency amounts in the MRP capital budgets would, like WGL's STRIDE proposal, require that customers pay for these unknown costs upfront. For the same reasons I specified in CN 9486, I recommend that any contingency amounts included in the budgets for the 2020 to 2023 capital addition should be removed from the MRP rate base.

[69] Initial Testimony of OPC Witness Larkin-Connolly in Case No. 9486 at p. 32

Q. What is the adjustment you are proposing?

A. I am recommending all gas capital contingencies identified by the Company be removed from the MRP. This includes reduction of $7.4 million in 2020 budget, $1.1 million in 2021 budget, $4.1 million in 2022 budget, and $0.01 million in 2023.[70]

VIII. CONCLUSION

Q. What are the recommended adjustments you are proposing be applied to the capital budgets underlying the MRP rate base?

A. I am proposing that the capital budgets for the MRP be reduced by $196.0 million in 2021, by $221.2 million in 2022, and by $235.9 in $2023. Table 37 below summarizes my recommended adjustments. The plant addition adjustments to the MRP have been provided to OPC Witness Effron so that the revenue requirements proposed by OPC will reflect the average rate base with these adjustments.

[70] Att. 1 to Staff 66-2

Table 37: Summary of Gas Plant Adjustments (million $)

		HTY	Bridge	MRP		
Line	**Category**	**2019**	**2020**	**2021**	**2022**	**2023**
(1)	GIMP*	$0.00	-$159.68	-$161.26	-$164.85	-$163.39
(2)	New Business - Gas	$0.00	-$3.18	-$3.00	-$6.47	-$9.27
(3)	System Performance - Gas	$0.00	-$13.35	-$14.51	-$14.92	-$17.75
(4)	Capacity Expansion - Gas	$0.00	$0.00	-$3.29	-$7.61	-$8.29
(5)	Tools	$0.00	-$1.52	-$1.12	-$1.29	-$1.24
(6)	IT	$0.00	-$3.75	-$5.49	-$24.22	-$60.00
(7)	Fleet	$0.00	-$0.68	-$0.93	-$0.96	-$0.98
(8)	Real Estate and Facilities	$0.00	-$28.53	-$31.52	-$37.77	-$31.54
(9)	Training	-$0.61	-$1.50	-$1.50	-$1.50	-$1.50
(10)	Other	$0.00	-$3.45	$3.39	$3.39	$2.17
(11)	Contingency		-$7.37	-$1.15	-$4.11	-$0.01
(12)	Shared Electric Adjustments		-$21.84	-$24.32	-$39.07	-$56.00
(13)	**Net Gas Plant Adjustments**	**-$0.61**	**-$201.18**	**-$196.05**	**-$221.24**	**-$235.80**

Q. Would you also summarize any adjustments that need to be applied to the HTY and bridge year capital additions?

A. Yes. I am also recommending that the starting rate base for the MRP be net of $0.61 million in 2019 plant additions and $201.2 in 2020 plant additions. These adjustments have also been provided to OPC Witness Effron to be reflected in MRP revenue requirements.

Q. Are there other adjustments that need to be made to the revenue requirement based on your recommendations?

A. Yes. The STRIDE surcharge revenue offset amounts of $7.5 million in 2021, $23.2 million in 2022, and $23.4 million in 2023 need to be removed. OPC Witness Effron makes these changes in his revenue requirement calculations as well.

Q. Does this conclude your testimony?

A. Yes. It does.

Attachment BLC-1: Curriculum Vitae (CV) of Brendan Larkin-Connolly

Education

2008	University of Massachusetts (Amherst, Massachusetts), MS, Resource Economics
2007	College of the Holy Cross (Worcester, Massachusetts), BA Economics

Employment Record

From 2013	**Current**
Employer	DHInfrastructure
Position Held and Description of Duties	Principal Manages projects related to regulation of the energy and water sectors.
From 2011	**2013**
Employer	Massachusetts DPU
Position Held and Description of Duties	Rate Analyst Provided technical advice and analysis on various ratemaking and finance cases involving investor-owned electric, natural gas, and water distribution companies
From 2008	**2011**
Employer	DHInfrastructure
Position Held and Description of Duties	Senior Analyst Conducted research related to water and energy sector regulation, privatization, renewable energy, and energy efficiency
From 2007	**2008**
Employer	University of Massachusetts
Position Held and Description of Duties	Research Assistant Assisted Resource Economics Department professor with research in economic theory and industrial organizations
Membership in Professional Associations	American Economic Association (AEA)
Other Training	The Basics: Practical Regulatory Training for the Electric Industry (NARUC/Center for Public Utilities, October 2011) Workshop on Demand Forecasting for Planning and Ratemaking (Institute of Public Utilities, July 2010)

Relevant Project Experience

2013–Current ***Principal, DHInfrastructure (Northampton, MA United States)***

- **IL ICC Docket 19-0271: AIC 2018 QIP Reconciliation**, 2019-2020. Ameren Illinois Gas Company (AIC) sought approval from the Illinois Commerce Commission (ICC) to reconcile $184 million in 2018 investments made through its QIP Rider. The Illinois Attorney General's Office (IL-AGO) hired DHInfrastructure to evaluate the appropriateness of the level and rate of investments Ameren had been making under its QIP program. To this end, in testimony submitted to ICC, Brendan compared the level of actual investments for 2018 and the prior three years to the three-year investment plans Ameren had submitted when its QIP Rider was approved. He found that QIP spend in 2018 was more than triple the maximum investment levels foreseen in its three-year plan. He then used data from Pipeline and Hazardous Materials Safety Administration (PHMSA) on leak and safety performance of the Company's distribution and transmission systems to show that there was no historical evidence that the rate at which QIP investments were made from 2014 to 2018 was justified. Based on these findings Brendan suggested that the ICC deny recovery of any QIP spend in excess of the amounts approved in the initial QIP plan—approximately $110 million. His recommendations also included suggestions that ICC require Ameren to submit various project cost and replacement indicators that would enable a more comprehensive evaluation of future Company's annual QIP activities.
- **MD PSC Case 9605: WGL 2019 Rate Case**, 2018 - 2018 (Expert Witness)—Washington Gas Light (WGL) filed a petition to Maryland's Public Service Commission (PSC) to increase its gas distribution base rates by $40 million. As part of this filing, WGL proposed to transfer $43 million from a capital tracker mechanism into base rates. The actual costs of the completed projects being proposed for transfer to rate base were consistently well above initial pre-construction estimates—on average 56 percent. Brendan submitted direct testimony on behalf of OPC on this issue. His written testimony focused on WGL's project cost management procedures. He identified that the Company lacked any specific procedures for addressing cost variances and documenting when a project scope change was identified. Based on his finding that absent such procedures the Company had not met its burden to demonstrate cost overruns had been incurred prudently he recommended certain capital costs be disallowed. Brendan subsequently advised OPC through settlement negotiations that inevitably included an agreement by the Company to work with OPC to develop specific procedures for project cost management.
- **Reviewing Gas Utility Replacement Filings in Maryland**, 2018 - 2019 (Lead Consultant/Utility Rates Expert)—Maryland's Strategic Infrastructure Development and Enhancement (STRIDE) program provides a cost recovery mechanism to incentivize local gas distribution companies to accelerate improvements in gas infrastructure. The Maryland OPC, within its role as a consumer advocate, wanted to hire a firm to support its staff in reviewing the STRIDE filings submitted to the Maryland PSC throughout the year. Brendan reviewed filings made by the three gas distribution companies in Maryland, prepared discovery on any issues he identified, and as necessary drafted comments for submission to the PSC.
- **MD PSC Case 9486: WGL Infrastructure Replacement Plan**, 2018 - 2018 (Lead Consultant/Utility Rates Expert)—Maryland's Strategic Infrastructure Development and Enhancement (STRIDE) program provides a cost recovery mechanism to incentivize local gas distribution companies to accelerate improvements in gas infrastructure. WGL filed a request to the Maryland PSC to establish its second five-year plan (STRIDE 2 Plan) and associated surcharge. WGL's STRIDE 2 plan included separate transmission and distribution plans consisting of the same 11 categories being replaced under their existing distribution and transmission plans, as well as one new

transmission asset category. Within its role as a consumer advocate, Maryland's OPC intervened in the proceeding on behalf of WGL's residential consumers and wanted to hire a firm to support its staff with its review of WGLs proposed STRIDE 2 plan and surcharge recovery mechanism. Brendan was the Lead Consultant and expert witness for the DHInfrastructure team hired by OPC. He conducted a comprehensive review of WGL's progress to date in completing replacements approved under its first five-year STRIDE plan. This analysis was used to determine the replacement rate that WGL had demonstrated it could achieve. The evaluation of the STRIDE 2 plan also included an assessment of whether the new transmission asset category met the eligibility requirements of the STRIDE statute and WGL's proposal to add a contingency to the project costs estimates used to set the STRIDE surcharge. Brendan submitted pre-filed direct and oral testimony on behalf of the OPC that focused on WGLs performance during its initial STRIDE program, its budgeting approach, and the STRIDE eligibility of the new transmission asset category.

- **DPU 18-GREC-04: Liberty Utilities 2018 Gas Infrastructure Reconciliation Filing**, 2018 - 2018 (Lead Consultant/Utility Rates Expert)--The Massachusetts Attorney General's Office of Ratepayer Advocacy (AGO) required the assistance of technical expert consulting services for its review of Liberty Utilities' reconciliation of 2017 GSEP and for review and approval of the 2018-2019 Gas System Enhancement Reconciliation Adjustment Factors (GSERAF) submitted to the DPU. Brendan analyzed the prudence and eligibility of GSEP costs. To this end, he reviewed project cost estimates and invoices and submitted discovery questions on anomalies encountered. He also prepared cross-examination questions, supported the AGO at the evidentiary hearings, and subsequently wrote sections of the initial brief submitted to the DPU.
- **DPU 18-GREC-03: National Grid 2018 Gas Infrastructure Reconciliation Filing**, 2018 - 2018 (Lead Consultant/Utility Rates Expert)--The Massachusetts Attorney General's Office of Ratepayer Advocacy (AGO) required the assistance of technical expert consulting services for its review of Boston Gas Company and Colonial Gas Company d/b/a National Grid's reconciliation of its 2017 GSEP and for review and approval of each companies' 2018-2019 GSERAF submitted to the DPU. Brendan analyzed the prudence and eligibility of GSEP costs. To this end, he reviewed project cost estimates and invoices and submitted discovery questions on anomalies encountered. He also prepared cross-examination questions, supported the AGO at the evidentiary hearings, and subsequently wrote sections of the initial brief submitted to the DPU.
- **MD PSC Case 9480: Columbia Gas of Maryland 2018 Rate Case**, 2018 - 2018 (Expert Witness)--Columbia Gas of Maryland (CMD) filed a petition to Maryland’s PSC to increase its gas distribution base rates by $5.9 million or 13.3 percent on April 13, 2018. The filing represented the sixth consecutive year that CMD had requested an increase in base rates. Within its role as a consumer advocate, Maryland's OPC intervened in the proceeding on behalf of CMDs residential consumers and wanted to hire a firm to review CMDs petition. Brendan submitted direct and oral testimony on behalf of OPC. His written testimony focused on the justification for CMDs petition to increase its base rates above the current rates. He reviewed CMDs proposed cost of service, class cost of service studies, distribution of revenues by customer class, and residential rate design. His recommendations on revenue requirements combined with the OPC's other recommendations on return on equity and depreciation amounted to a $2.5 million or 40 percent reduction from CMD's request. Brendan subsequently

advised OPC through settlement negotiations and provided oral testimony on an environmental remediation issue not included in the settlement agreement.

- **MD PSC Case 9479: Columbia Gas of Maryland Infrastructure Replacement Plan**, 2018 - 2018 (Lead Consultant/Utility Rates Expert)—Maryland’s Strategic Infrastructure Development and Enhancement (STRIDE) program provides a cost recovery mechanism to incentivize local gas distribution companies to accelerate improvements in gas infrastructure. Columbia Gas of Maryland (CMD) filed a request to Maryland's PSC to establish its second five-year STRIDE Plan (STRIDE 2) and associated surcharge. For STRIDE 2, CMD proposed to accelerate replacement of bare steel and cast-iron mains from 7.56 miles to 8.5 miles per year. Within its role as a consumer advocate, Maryland's OPC intervened in the proceeding on behalf of CMDs residential consumers and wanted to hire a firm to support its staff with its review of CMDs proposed STRIDE 2 plan and surcharge recovery mechanism. Brendan’s analysis focused on whether the historical leak record of bare steel and cast-iron mains supported the request to further accelerate replacement. He also identified problems with the annual budgets the Company had made for STRIDE 2. He submitted pre-filed testimony that summarized his findings and recommended that PSC deny approval of STRIDE 2 and require CMD to submit a new plan that maintained its current replacement rate. Following a settlement agreement, Brendan reviewed all documents submitted in compliance with the agreement and submitted pre-filed testimony on behalf of OPC supporting the settlement.
- **MD PSC Case 9468: BGE STRIDE 2**, Maryland, 2018 (Expert Witness) — BGE filed a request to Maryland’s PSC to establish its second 5-year STRIDE 2 Plan and associated surcharge under the provisions of Maryland Public Utilities Article §4-210. BGE was currently operating under its original STRIDE plan that established a timeline for replacing all leak-prone gas mains and services by 2043. Maryland’s OPC hired DHInfrastructure to review the STRIDE 2 plan and associated surcharges submitted by BGE. Brendan was the Lead Consultant and expert witness for the DHInfrastructure team hired by OPC. He submitted direct testimony on behalf of the OPC. His testimony focused on the justification for BGE’s proposal to increase its replacement activities above the pace set in its existing STRIDE plan. First, he compared BGE’s projected timeline for replacement of all leak-prone infrastructure under the original STRIDE to a set of industry peers to counter the claim that existing replacement activities lagged behind the industry average timeline. Next, he presented the leak-rate history of BGE to show that there was no change in the condition of the leak-prone infrastructure that warranted an increase in replacement plans. He then produced a cost-benefit analysis of the STRIDE 2 plan against the original STRIDE to further investigate whether there was any justification for the proposed increase in replacement activities. Finally, based on his analysis he recommended that PSC deny approval of STRIDE 2 and require BGE to submit a new plan that maintains its current replacement rate.
- **2016 GREC Filings, Massachusetts,** June 2017-December 2017—The MA-AGO required the assistance of technical expert consulting services for the investigation and litigation of the review and approval of the reconciliation of 2016 GSEP and for review and approval of the GSERAF (“2016 GREC Filings”) submitted to the Department. DHInfrastructure was asked to provide consulting service on the petitions of: Fitchburg Gas and Electric Company, docketed as DPU 17-GREC-01; and Boston Gas Company and Colonial Gas Company each d/b/a National Grid, docketed as DPU 17-GREC-03. Brendan was the team leader on this project and supported the MA-AGO in all facets of the docket proceedings, including review of initial and compliance filings, drafting and review of discovery questions, interrogation of expert witnesses, and preparation of briefs.

- **NARUC Rwanda Partnership Exchange on Tariffs**, May 2017 (Volunteer Expert)—The NARUC with the support of the United States Agency for the International Development launched a bilateral partnership with the RURA in 2016. The NARUC-RURA partnership exchange aims to build RURA's capacity to carry-out its economic and financial regulatory responsibilities with a specific focus on tariff setting. To this end, NARUC invited staff of NARUC institutions and other industry experts to volunteer for a partnership exchange mission on setting cost recovery tariffs using Microsoft Excel. As a NARUC volunteer expert, Brendan Larkin-Connolly was asked to provide RURA staff with insight on using Excel in the tariff setting process. He gave RURA staff an introductory lesson on how to use Excel and discussed functions that are useful when determining tariffs. In preparation for this mission, he also built a tariff model using cost, asset details, and billing data submitted by RURA to NARUC. During the mission, RURA staff were then led through each section of the model and asked to implement functions of the models using the Excel skills learned in the previous module.
- **DPU 16-105: Eversource Energy Utility-Scale Solar, Massachusetts,** September 2016-December 2016 (Principal Consultant)—Eversource Energy submitted a request to the Massachusetts's DPU for pre-approval to develop, construct, own, and operate 62 MW of solar PV capacity on company-owned sites. Eversource's Petition also included a request for approval of a new Solar Expansion Cost Recovery Mechanism ("SECRM"), a surcharge for recovering the incremental revenue requirement associated with the proposed solar program. Brendan was the Lead Consultant for the DHInfrastructure team hired by the MA-AGO to provide expert advice to staff throughout the docket. He submitted both direct and oral testimony on behalf of the MA-AGO. His testimony focused on the potential bill impacts of Eversource's cost recovery proposal and included recommendations to help mitigate the impact on ratepayers. In addition, Brendan reviewed docket filings; drafted discovery; provided MA-AGO attorneys with support during cross-examination of company witnesses at evidentiary hearings; and contributed to written briefs.
- **2015 GREC Filings, Massachusetts,** June 2016—The MA-AGO required the assistance of technical expert consulting services for the investigation and litigation of the review and approval of the reconciliation of 2015 GSEP and for review and approval of the GSERAF ("2015 GREC Filings") submitted to the Department. DHInfrastructure was asked to provide consulting service on the petitions of: The Berkshire Gas Company, docketed as DPU 16-GREC-02; and Boston Gas Company and Colonial Gas Company each d/b/a National Grid, docketed as DPU 16-GREC-03. Brendan was the team leader on this project and supported the MA-AGO in all facets of the docket proceedings, including review of initial and compliance filings, drafting and review of discovery questions, interrogation of expert witnesses, and preparation of briefs.
- **Nauru Power Tariff and Subsidy Reform,** 2015 (Team Leader)—The Government of Nauru requested TA from the ADB to reform electricity tariffs for its national utility provider, NUC. This TA aimed to contribute to long-term sustainability and viability of NUC as an electric utility and to support proposed investments in NUC's generation facilities under ADB's Nauru Electricity Security and Sustainability Project. Brendan led the tariff reform initiative which in addition to tariff setting recommendations included a Willingness-to-Pay survey of residential customers and a subsidy analysis of existing Government subsidies. As part of the tariff setting reform he developed revenue requirement, cost of service, and tariff design recommendations for NUC to implement.
- **Armenia Water Tariff Study,** 2014 (Tariff Specialist)—Water and wastewater tariffs in Armenia are very low and do not cover operating and maintenance expenditures or provide sufficient funds to adequately deal with asset rehabilitation. Consequently, there are looming concerns about the long-term sustainability of service provision by existing PPP arrangements. The World Bank Group requested assistance in developing a water sector tariff study for Armenia to assess the levels of the current water and wastewater tariffs in terms of cost recovery. The World Bank wanted a description of a number of tariff scenarios, taking into account

financial, economic, efficiency and equity objectives. Lastly, a plan of actions would be developed to move from the current tariff levels and structure to an agreed future tariff level and structure. Brendan provided advice on the design options for end-user tariffs. He prepared SWWOT analysis on various tariff design options (uniform volumetric, non-uniform volumetric, increasing block, and fixed) and used this analysis to provide the Government with a recommended tariff structure.

- **Development of Tariff Setting Methodology in the Kyrgyz Republic,** 2013 (Tariff Expert)—A lack of a clear regulatory structure and tariff setting methodology in the Kyrgyz Republic undermines the incentives for good performance and sound management of power and district heat utility companies. The World Bank aims to support the Kyrgyz Republic establish a sustainable, transparent, and equitable tariff setting methodology for the electric and district heat sectors. DHInfrastucture was asked to support this objective by recommending a framework for setting tariffs and establishing KPIs. Mr. Larkin-Connolly is reviewing the existing financial structure of the energy sector and developing a tariff setting methodology that takes into account the existing institutional structure of the energy sector and international best practice. He is also providing recommendations for options in establishing protections for low-income customers and the development of transition mechanisms for potential tariff increases.

2011–2013 ***Rate Analyst, DPU (Boston, MA United States)***

- **DPU 13-75: Bay State Gas Company Rate Case, United States** 2013 (Rate Analyst)—Bay State Gas Company requested an increase in base rates for the second year in a row because it argued that its current rate structure did not allow for a reasonable opportunity to earn its permitted rate of return. As a solution to its earning deficiency the Company proposed to create a regulatory asset for the recovery of depreciation, interest, and tax costs incurred on leak-prone pipe replacement projects between the in-service date and when the Company begins earning a recovery on the addition. The Company also proposed six months of post-test year plant additions in order to account for the additional regulatory lag resulting from an extension of the DPU's statutory rate suspension period from six to ten months. Mr. Larkin-Connolly conducted a review of Bay State Gas Company's operating costs over the previous ten years in order to assess the reason for the Company's inability to earn its rate of return. His analysis showed that while costs related to investment in plant had increased, the largest cost drivers were administrative and general expenses. He also reviewed the Company's proposed test year and post-test year plant additions to determine whether they were both prudent and used and useful.
- **DPU 12-115: National Grid Electric 2013 RDM, United States** 2012-2013 (Rate Analyst)—National Grid Electric Company submitted to the DPU for approval of its annual Revenue Decoupling Mechanism (RDM) filing. National Grid's RDM is based on a comparison of benchmark revenue per class to actual billed revenue per class. In addition, the Company's RDM filing also requested approval for its 2013 Capital Expenditure Factor (CapEx) that allows for recovery of certain additions to utility plant in 2012. Mr. Larkin-Connolly reviewed the Company's calculation of both the RDM and CapEx factors and helped draft an Order initially approving the rates subject to reconciliation following a final review after hearings and comments from interveners.
- **DPU 12-97: Western Massachusetts Electric Company (WMECo) Revenue Neutral Rate Design** 2012-2013 (Rate Analyst)—As part of a prior settlement agreement with the Attorney General of Massachusetts, WMECo agreed to file a new rate design aimed at aligning customer distribution rates closer to equalized rates of return. The change in distribution rates coincided with a permanent reduction in one of the Company's reconciling mechanisms that allowed for the increase in distribution rates of some customers without an overall increase in their total bill. The need for a distribution rate realignment was due to the Company's prior base rate proceeding in which rates were set for some customers below equalized rates of return leading to cross-subsidization between classes. Mr. Larkin-Connolly prepared a presentation on the Company's two rate design proposals to inform the Commission about the advantages and disadvantages of each proposal. The Commission used his analysis to select a design that both

moved classes closer to equalized rates of return and gave all customer classes a reduction in total bills.

- **DPU 12-88: Western Massachusetts Electric Company 2012 Annual Rate Filing, United States** 2012 (Rate Analyst)—Western Massachusetts Electric Company requested approval for adjustments to several reconciling mechanisms proposed to take place on January 1, 2013. These mechanisms included: (1) transmission charge; (2) retail transmission cost adjustment; (3) basic service cost adjustment and uncollectible/bad debt; (4) basic service cost true-up; and (5) attorney general consultant expenses. Mr. Larkin-Connolly reviewed all proposed changes and checked for consistency with the approved tariffs. He also verified that the proposed changes were properly accounted for in the summary tariff the Company is required to submit at the beginning of each year.
- **DPU 12-25: Bay State Gas Company Rate Case, United States** 2012 (Rate Analyst)—Bay State Gas Company requested a $29.2 million rate increase from the Department. The Company's proposal included the use of a future test year, modifications to an existing capital tracker, and updates to its decoupling mechanism. Mr. Larkin-Connolly was responsible for reviewing these proposed regulatory mechanisms. Given the Department's standard of basing rates on an historic test year, the focus on his investigation was whether the Company had presented a sufficient reason for needing to break from this tradition. He presented his findings and an analysis on the impact of using a future test year versus the historic test year to the Department's Commissioners in order to provide them the necessary background information for making a decision on the Company's proposal. Also, in response to the Company’s failure to meet the Department’s expectations to increase leak-prone pipe replacement under its existing capital tracker mechanism, he helped develop an annual mileage threshold the Company will have to meet in order to earn recovery of the investments outside of a rate case. In addition, Mr. Larkin-Connolly reviewed the plant additions the Company proposed to add to rate base. This review included an examination of project reports and cost-variance analysis for 272 projects with costs greater than $50,000.
- **Electric Rate Database Project, United States** 2012 (Rate Analyst)—The Office of Energy and Environmental Affairs (EEA) and the Attorney General of Massachusetts wanted to develop an on-line database the public could use to track electric rates historically. Mr. Larkin-Connolly was asked to represent the Department on a committee put together to discuss how the database would be developed. He attended meetings with representatives from EEA, the Attorney General’s Office, and the four electric distribution companies. Based on his experience with database modeling he provided recommendations to EEA on how to create a form for each Company to submit monthly rate data.
- **DPU 12-11: National Grid Gas Off-Peak RDAF, United States** 2012 (Rate Analyst)—National Grid Gas Company submitted its off-peak period Revenue Decoupling Adjustment Factor (RDAF) for Department approval. The Company’s decoupling mechanism is based on a revenue-per-customer approach where a benchmark revenue-per-customer for each customer class is compared to the actual billed revenue-per-customer in the previous May through October off-peak period. Mr. Larkin-Connolly checked the Company’s calculation of the RDAF for consistency with the tariff approved in the Company’s last rate case. He also reviewed National Grid’s forecasting method used to project the total kWhs used in the RDAF calculation and interviewed the Company’s forecasting expert to provide a more complete description of the forecasting approach.
- **DPU 11-90: NSTAR Electric Company 2011 Distribution Rate Adjustment/Reconciliation Filing**, 2011 (Rates Analyst)—NSTAR Electric Company submitted its annual reconciliation filing to the Department for adjustment’s to distribution rates, transition charge, transmission charge, and basic service rates. Mr. Larkin-Connolly was in charge of reviewing the Company's Simplified Incentive Plan (SIP) adjustment. The SIP is an annual adjustment based on a formula that uses inflation and a productivity offset to set new distribution rates. He verified that the

formula was implemented according to the terms of the 2005 Settlement Agreement that established the SIP.

- **DPU 11-56: National Grid Storm Costs, United States** 2011-2013 (Rates Analyst)—In response to a Department order in DPU 09-55, National Grid Electric Company submitted an audit of costs incurred during an ice storm in 2008. For the Company to recover the negative balance in its storm reserve fund, the previous Order required the Company to demonstrate all storm costs were incurred prudently. In DPU 11-56, the Company submitted pre-filed testimony describing the accounting and audit process and filed all available cost invoices. Mr. Larkin-Connolly represented the rates department in the DPU's review of this case. He validated the documentation provided by the Company by checking all listed costs to actual invoice totals. He submitted discovery questions for all cost items in which he found discrepancies. His review led the Company to remove $33,346 in expenses from its filing.
- **DPU 11-78 & DPU 11-79: National Grid Gas Company Request for Long-Term Financing, United States** 2011 (Rate Analyst)**—**National Grid Gas requested Department approval to acquire $550 million in new long-term debt. The Company requested flexible terms in order to quickly enter the market and capture the benefits of existing low interest rates. Mr. Larkin-Connolly was in charge of the preparing the capital review and description of financing sections for the Department's Order. His review of the Company's petition included extensive analysis of their utility plant account and current long-term debt.
- **DPU 11-RAAF-6: New England Gas Company 2011 RAAC Adjustment, United States** 2011 (Rate Analyst)**—**New England Gas Company submitted its annual Residential Assistance Adjustment Clause ("RAAC") to the Department for approval. The RAAC is a per therm charge that reconciles foregone revenue due to low-income discount rates and also allows for the recovery of arrear forgiveness and any associated costs incurred while maintaining these low-income programs. Mr. Larkin-Connolly reviewed New England's filing, checked that the proposed rate was calculated according to the RAAC tariff approved in the Company's prior rate case, and verified that all costs included were directly related to these low-income programs.

2008–2011 Senior Analyst, DH Infrastructure (Northampton, MA United States)

- **US Energy Policy and Regulation, United States** 2011 (Lead Analyst)— Japan's New Energy and Industrial Development Organization (NEDO) asked DHInfrastructure for an update on energy sector policy and regulation in the US. NEDO specifically wanted to know how regulators were approaching the installation of Smart Grid technologies into the grid. Mr. Larkin-Connolly was lead analyst on this project. He prepared a memo on trends in smart grid policy and regulation at the federal and state levels. As part of the state regulation section he wrote case studies on decisions made by Public Utility Commissions in Maryland and Colorado where Smart Grid proposals were rejected.
- **California Electricity Crisis Proceedings, United States** 2010-2011 (Economic Analyst)—PG&E, a large US electric utility, wanted to demonstrate to the FERC that costs claimed by power marketers did not offset refunds owned to PG&E as a result of the price spikes in the California electricity market during 2000-2001. Mr. Larkin-Connolly supported the preparation of expert testimony on behalf of PG&E. He built a database of electric market bid data and used the database to identify economic withholdings of power marketers during the crisis. He also built a bid-stack model that he used to estimate what the competitive price for electricity would have been in California absent market manipulation.
- **Reform of Public Urban Service Organizations in Mongolia,** 2010 (Analyst)—The Government of Mongolia wanted to improve service quality and cost recovery of multi-utilities that provide water, sewerage, heating, and solid waste disposal services in Mongolia's provincial capitals. The ADB asked for recommendations on how the Government could achieve these goals by adopting alternative institutional arrangements for delivery of these services. Brendan wrote case studies on different service delivery arrangements used elsewhere in the world. These cases were presented to ADB and the Government of Mongolia as potential arrangement options.

- **Smart Grid Policy and Regulation, United States 2009-2010** (Lead Analyst)—Japan's New Energy and Industrial Technology Organization (NEDO) wanted to know about the use of "Smart Grid" technologies in the United States. Mr. Larkin-Connolly was the primary author of this report. Mr. Larkin-Connolly's analysis included a summary of smart grid technologies, the benefits of a modern power grid, and government policy supporting implementation. In order to provide NEDO with a detailed account of current industry conditions Mr. Larkin-Connolly interviewed multiple industry leaders of the public and private sector. He also completed a survey of all Smart Grid projects in the planning stages or already in development.

List of Direct Testimony Experience

State	Case/ Docket No.	Case/Docket Description	Testified on behalf	Topic(s)
MA	DPU-16-105	Petition of Eversource Energy, for approval to construct, own, and operate solar generation facilities	Mass. Attorney General's Office	Recovery surcharge bill impacts Pre-approved costs
MD	Case 9468	BGE's application for approval of a new gas system strategic infrastructure development and enhancement plan and accompanying cost recovery mechanism	Maryland Office of People's Counsel	Leak-prone infrastructure replacement plan Cost-benefit analysis O&M offset Rate impacts
MD	Case 9479	CMD's application for approval of its second 5-year STRIDE 2 Plan and associated surcharge	Maryland Office of People's Counsel	Leak-prone infrastructure replacement plan O&M offset Rate impacts
MD	Case 9480	CMD's application for approval of base rate adjustments	Maryland Office of People's Counsel	Cost of service and distribution by customer class Rate impacts
MD	Case 9486	WGL's application for approval of its second 5-year STRIDE 2 Plan and associated surcharge	Maryland Office of People's Counsel	Leak-prone replacement activity performance Asset special treatment eligibility
MD	Case 9605	WGL's application for approval of base rate adjustments	Maryland Office of People's Counsel	Capital additions
IL	Docket 19-0271	AIC's petition pursuant to rider QIP of schedule of rates for gas service to initiate a proceeding to determine the accuracy and prudence of qualifying infrastructure investment	Illinois Attorney General's Office	Capital tracker mechanism cost reconciliation
IL	Docket 20-0308	AIC's proposed general increase in rates and revisions to other terms and conditions of service	Illinois Attorney General's Office	Capital additions

Attachment BLC-2: Discrete Gas Projects

			HTY	Bridge	MYP		
Project	Witness	Category	2019	2020	2021	2022	2023
55633: Granite Pipeline-Stokes Drive-Russell Rd	Burton	System Performance - Gas	$0.45	$1.30	$1.84	$4.45	$0.41
58028: Downtown Pipeline Phase 1 (Mt Royal Ave)	Burton	System Performance - Gas	$0.87	$0.13	$12.36	$13.27	$14.96
58447: Harbor Crossing - Upgrades for In-Line Inspection	Burton	System Performance - Gas	$0.02	$5.19	$0.00	$0.00	$0.00
58477: Severn River Bridge Main Replacement	Burton	System Performance - Gas	$0.00	$5.11	$1.32	$0.00	$0.00
59322: Spring Gardens Liquified Natural Gas (LNG) Boil Off Compressor	Burton	System Performance - Gas	$1.17	$2.97	$0.00	$0.00	$0.00
59616: Howard County Station 489 Heater Replacement	Burton	System Performance - Gas	$0.40	$1.35	$0.00	$0.00	$0.00
60080: Granite Pipeline-Gate Station to Lord Baltimore	Burton	System Performance - Gas	$0.61	$1.20	$0.00	$19.49	$0.00
60691: Gate Station-Manor	Burton	System Performance - Gas	$6.83	$0.00	$0.00	$0.00	$0.00
60693: Gate Station-Owings Mills	Burton	System Performance - Gas	$0.00	$2.27	$2.53	$11.43	$8.08
60704: Plant Major Infrastructure - Valve House Phase 4	Burton	System Performance - Gas	$0.26	$6.88	$0.00	$0.00	$0.00
60705: Leadenhall Isolation / Removal of Existing Header	Burton	System Performance - Gas	$0.00	$0.12	$4.56	$0.00	$0.00
61207: Granite Pipeline-Leakin Park	Burton	System Performance - Gas	$10.35	$0.12	$0.00	$0.00	$0.00
58510: New Business Gas Weller Development Chapter 1	Biagiotti	New Business - Gas	$0.00	$1.18	$0.46	$0.26	$0.29
58968: New Business Crain Highway Conway Road Gas Approach	Biagiotti	New Business - Gas	$4.09	$0.77	$0.00	$0.00	$0.00

Attachment BLC-3: Gas Distribution and Common Capital Projects Less than $1 million (million $)

Capital Category	Total by Category in Witness Exhibits [1]					Projects >$1 Million [1]					Projects <$1 Million [2]				
	HTY	Bridge	MRP			HTY	Bridge	MRP			HTY	Bridge	MRP		
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
Facilities Relocation - Gas	$28.26	$9.49	$6.22	$6.57	$7.03	$28.26	$9.49	$6.22	$6.57	$7.03	$0.00	$0.00	$0.00	$0.00	$0.00
New Business - Gas	$60.26	$58.30	$57.12	$59.84	$64.28	$60.19	$58.22	$57.04	$59.77	$64.21	$0.07	$0.07	$0.07	$0.08	$0.08
Tools	$4.77	$5.89	$4.74	$4.96	$5.05	$3.75	$4.23	$3.47	$3.52	$3.65	$1.03	$1.66	$1.27	$1.44	$1.40
Capacity Expansion - Gas	$10.95	$20.99	$14.79	$19.41	$20.38	$10.95	$20.99	$14.79	$19.41	$20.38	$0.00	$0.00	$0.00	$0.00	$0.00
Corrective Maint Gas	$47.00	$49.73	$44.42	$38.07	$32.33	$46.26	$48.59	$43.53	$37.41	$31.65	$0.74	$1.15	$0.88	$0.66	$0.69
GIMP	$166.9	$159.7	$161.3	$164.9	$163.4	$166.9	$159.7	$161.3	$164.9	$163.4	$0.00	$0.00	$0.00	$0.00	$0.00
System Performance - Gas	$69.81	$92.14	$73.72	$101.82	$83.73	$68.73	$91.55	$73.20	$101.3	$83.52	$1.08	$0.59	$0.52	$0.53	$0.20
Customer Operations	$18.35	$15.00	$13.94	$9.43	$9.58	$16.36	$12.88	$11.58	$7.85	$7.95	$1.99	$2.11	$2.36	$1.58	$1.62
BSC	$5.95	$3.29	$2.33	$2.27	$2.33	$2.55	$2.48	$2.21	$2.16	$2.21	$3.41	$0.81	$0.11	$0.12	$0.12
Fleet	$21.07	$29.08	$21.92	$20.62	$17.79	$21.07	$29.08	$21.92	$20.62	$17.79	$0.00	$0.00	$0.00	$0.00	$0.00
IT	$135.9	$138.2	$83.63	$82.31	$81.81	$125.2	$128.9	$80.80	$80.80	$80.9	$10.7	$9.22	$2.83	$1.51	$0.92
Other	$17.16	$51.35	$47.90	$63.31	$34.58	$16.07	$48.56	$45.23	$61.34	$32.66	$1.09	$2.79	$2.67	$1.97	$1.92
Real Estate and Facilities	$43.53	$81.05	$46.19	$42.74	$36.61	$39.04	$79.23	$44.93	$41.51	$35.37	$4.50	$1.82	$1.27	$1.22	$1.24
Training	$0.61	$1.50	$1.50	$1.50	$1.50	$0.61	$1.50	$1.50	$1.50	$1.50	$0.00	$0.00	$0.00	$0.00	$0.00

Note: (1) Totals by category and projects greater than $1 million are taken from Exhibits DMV-8, RDB-1, AA-1, ACB-1, and TAO-1. (2) Actual/budget amounts for projects less than $1 million = Total by category – Total by category for projects greater than $1 million.

APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR AN ELECTRIC AND GAS MULTI-YEAR PLAN

CASE NO. 9645

DATA RESPONSES REFERENCED

IN THE DIRECT TESTIMONY OF BRENDAN LARKIN-CONNOLLY

BGE response to OPC 7-10
BGE response to OPC 7-12
BGE response to OPC 7-13
BGE response to OPC 11-8
BGE response to OPC 12-17
BGE response to OPC 19-2

BGE response to Staff 14-06
BGE response to Staff 20-21
BGE response to Staff 20-22
BGE response to Staff 22-9
BGE response to Staff 22-9
BGE response to Staff 22-15
BGE response to Staff 22-26
BGE response to Staff 22-28
BGE response to Staff 23-10
BGE response to Staff 43-46
BGE response to Staff 45-9
BGE response to Staff 45-19
BGE response to Staff 45-22
BGE response to Staff 45-31
BGE response to Staff 47-28
BGE response to Staff 51-02
BGE response to Staff 51-05
BGE response to Staff 60-14
BGE response to Staff 60-14
BGE response to Staff 66-02

August 14, 2020

Case No. 9645
Baltimore Gas and Electric Co.
Response to OPC Data Request 7
Request Received: 06/12/2020
Response Date: 06/26/2020
Sponsor: A. Christopher Burton

Item No.: OPCDR07-10

Refer to the pre-filed testimony of Company Witness Burton at page 21, where the GIMP category is discussed. Please clarify if the GIMP category is synonymous with STRIDE. In other words, clarify if all STRIDE work is completed under the GIMP category and if *only* STRIDE work is completed under the GIMP category.

RESPONSE:

The GIMP category is comprised of only STRIDE related work. No other categories contain STRIDE work.

Case No. 9645
Baltimore Gas and Electric Co.
Response to OPC Data Request 7
Request Received: 06/12/2020
Response Date: 06/26/2020
Supplemental Response Date: 07/10/2020
Sponsor: A. Christopher Burton

Item No.: OPCDR07-12

Refer to the Company's response to Staff DR 14-6. Identify the unit costs for pre-1970 ¾" high-pressure steel services that are used to derive the budgets presented in the Service Replacement Program table and explain the unique cost drivers that have led the unit costs for these services to be adjusted.

RESPONSE:

BGE did not apply a set "per unit" cost to determine the forecasts for the Service Replacement Programs related to pre-1970 ¾" high pressure steel services (shown in the GIMP category). Instead, these forecasts are based upon historical spend and work quantities, with the assumption of performing a similar level of work each year through 2023 to eliminate the remaining approximately 21,000 pre-1970 ¾" high pressure steel services on BGE's system.

BGE discussed the drivers that have affected service replacement program costs in multiple prior STRIDE program filings dating back to 2018. For example, in BGE's STRIDE 2020 project list filing, dated November 1, 2019 (Maillog #227350), BGE explained:

> In STRIDE filings made with the Commission in late 2018 and throughout 2019, as well as discussed at the September 18, 2019 Commission hearing on BGE's 2019 STRIDE mid-year report, BGE has encountered difficulties in procuring and retaining long-term enough qualified and cost-effective resources to complete replacement of pre-1970 ¾" high pressure steel services at the further accelerated pace first proposed by the Company and approved by the Commission during the proceeding to consider BGE's STRIDE 2 plan application. The reasons for the shortage of qualified personnel involve constraints in the labor market due to gas asset replacement work being undertaken by numerous utilities nationwide following the high profile 2018 events in Dallas, Texas and Massachusetts, as well as an historically low nationwide unemployment rate. This has resulted in continuing increasing costs to replace gas service assets.

Further details on these drivers and the Company's response and mitigating activities can be found in the November 1, 2019 filing.

SUPPLEMENTAL RESPONSE:

The Company does not use "per unit" costs as the starting point to develop forecasts for the Service Replacement Programs related to the pre-1970 ¾" high pressure steel service asset class. This means that BGE does not start with a target cost-per unit in mind and build the forecast around that value. Rather, BGE begins developing its forecasts by aiming to replace a quantity of this asset each year that is in line with the level of work from the prior year, yet still ensures that BGE remains on track to complete the replacement of this asset class by the end of 2023. That goal equates to an annual replacement of between 5,000 and 5,500 services, with some variation year-to-year. BGE then applies that targeted replacement number against estimates of cost-per unit values to arrive at a forecasted budget. The forecasted costs provided in the response to StaffDR14-06 are based on the following projected annual replacements and costs-per-unit:

Pre-1970 ¾" HP ST services	**2020**	**2021**	**2022**	**2023**
Multiyear Rate Plan	$39,326,382	$40,567,645	$42,811,109	$36,564,695
Replacements per year	5,286	5,453	5,755	4,915
Yearly cost per	$7,439.72	$7,439.51	$7,438.94	$7,439.41

BGE has explained in prior STRIDE hearings as well as in prior STRIDE filings the drivers behind the rising costs associated with the Service Replacement Programs for pre-1970 ¾" high pressure steel services and why current cost figures are higher than what was first included in BGE's STRIDE 2 application (Case No. 9468) filed December 1, 2017.

Case No. 9645
Baltimore Gas and Electric Co.
Response to OPC Data Request 7
Request Received: 06/12/2020
Response Date: 06/26/2020
Sponsor: A. Christopher Burton

Item No.: OPCDR07-13

Refer to the Company's response to Staff DR 14-6. Please provide the planned annual pre-1970 ¾" high-pressure steel services being replaced that corresponds to the budget presented in the Service Replacement Program table.

RESPONSE:

The work at issue in the MYP is based upon historical spend and work quantities, with the assumption of performing a similar level of work each year through 2023 to eliminate the remaining approximately 21,000 pre-1970 ¾" high pressure steel services on BGE's system. For more information, please see BGE's response to OPCDR07-12.

Case No. 9645
Baltimore Gas and Electric Co.
Response to OPC Data Request 11
Request Received: 06/26/2020
Response Date: 07/13/2020
Sponsor: Robert D. Biagiotti

Item No.: OPCDR11-08

Refer to the testimony of Company Witness Biagiotti at page 18. Given that Pay It Forward will now be reviewed through a docketed proceeding, clarify if the Company agrees that these amounts should be removed from the MYP. If so, provide the corresponding adjustments that need to be made to each year in the MYP.

RESPONSE:

No, the Company does not agree the amounts budgeted for Pay It Forward should be removed from the MYP. Please see the responses to OPCDR11-05 and OPCDR11-07.

Case No. 9645
Baltimore Gas and Electric Co.
Response to OPC Data Request 12
Request Received: 06/30/2020
Response Date: 07/15/2020
Sponsor: Ajit Apte

Item No.: OPCDR12-17

Referring to Company Exhibit AA-1, Page 44, please provide the budgeted and actual vegetation management expenses by month in 2020 to date.

RESPONSE:

Please see *Attachment 1*.

Case No. 9645
OPC Data Request 12
Item 17
Attachment 1

Vegetation Management-2020 Budget and Actuals YTD	**January**		**February**		**March**		**April**		**May**	
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual
61054:VM Distribution Reactive	$ 256,033	$ 223,672	$ 256,037	$ 173,042	$ 256,037	$ 230,766	$ 256,037	$ 127,317	$ 256,037	$ 204,908
61055:VM Distribution Routine	1,834,540	2,056,628	1,872,389	2,146,904	2,090,361	2,808,665	2,152,641	2,116,815	2,293,444	2,275,830
61058:VM Transmission Substation Vegetation Mgmt-Distr/Trans	92,281	14,211	92,778	22,326	93,829	68,374	92,973	84,607	91,677	112,876
61059:VM Transmission Vegetation Mgmt - Gas ROW G1753	79,670	32,809	80,100	19,689	81,024	25,411	80,279	70,595	79,154	25,409
Projects with less than $1M forecasted annual spend	195,118	33,854	195,118	30,958	195,118	221,626	195,118	162,760	132,991	499,400
Grand Total	**$ 2,457,642**	**$ 2,361,174**	**$ 2,496,422**	**$ 2,392,919**	**$ 2,716,369**	**$ 3,354,842**	**$ 2,777,048**	**$ 2,562,094**	**$ 2,853,303**	**$ 3,118,423**

Case No. 9645
Baltimore Gas and Electric Co.
Response to OPC Data Request 19
Request Received: 07/13/2020
Response Date: 07/27/2020
Sponsor: David M. Vahos

Item No.: OPCDR19-02

Refer to the previous question and Part 2 of the pre-filed testimony of Company Witness Vahos at pages 34-35. Mr. Vahos notes that "the 2021-2023 budget underlying the MYP revenue requirement calculations includes budgeted STRIDE surcharge revenues." Confirm that the STRIDE revenues calculated in the prior response reflect the STRIDE surcharge revenues being referenced by Mr. Vahos and identify where in the filing (i.e. what workpaper or exhibit) the STRIDE revenue offset to base rates is applied or reflected.

RESPONSE:

The STRIDE surcharge revenues, which are included in the MYP revenue requirement and offset the requested MYP base rate revenue requirement increase associated with the forecasted STRIDE investments, can be found in the response to StaffDR60-14, Attachments 1 through 3, in the column titled "Revenues" (which is shaded yellow). Specifically, these STRIDE surcharge revenues are included in the "Sale of Gas" row on Company Exhibit DMV-3G-Updated.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 14
Request Received: 05/29/2020
Response Date: 06/04/2020

Item No.: StaffDR14-06

Please explain how any projected STRIDE expenditures in the Bridge Year and MRP differ from those filed in Case No. 9468. Will current STRIDE cost projections results in changes to cumulative program main mileage completed and services replaced in the MRP? Please describe the rationale for any changes to either expenditures or units completed.

RESPONSE:

STRIDE projections for BGE Operation Pipeline filed in the Multi-Year Plan and described in Witness Burton's testimony are not significantly different than those filed in Case No. 9468. Cumulative program main mileage (as well as associated services) replaced, averaging 48 miles of Cast Iron and Bare Steel Main per year, also remains unchanged compared to what was filed in Case No. 9468.

Operation Pipeline	2020F (Bridge)	2021F	2022F	2023F
Multi-Year Plan	$ 120,352,364	$ 120,692,755	$ 122,035,734	$ 126,829,973
STRIDE 2 - Case No. 9468	$ 117,000,000	$ 120,000,000	$ 123,000,000	$ 126,000,000

For the Pre-1970 ¾" High Pressure Steel Service Replacement program, the projections filed in the Multi-Year Plan reflect the shift that BGE described in the 2020 Project List filing (ML# 227350). Specifically, unit costs are expected to remain higher than those originally filed as part of Case No. 9468. As a result of this cost pressure, as well as improvement in performance data of the asset, BGE has elected not to further accelerate the replacement rate of pre-1970 ¾" high pressure steel services to the level that was indicated in Case No. 9468 (10,000/year). The projections in the Multi-Year Plan instead corresponds to completing renewal of all pre-1970 ¾" high pressure steel services by 2023, rather than in 2021 as was proposed in Case No. 9468. However, cumulative pre-1970 ¾" high pressure steel services replacement quantity remains unchanged compared to what was filed in Case No. 9468.

Pre-1970 ¾" HP ST services	**2020**	**2021**	**2022**	**2023**
Multi-Year Plan	$ 39,326,382	$ 40,567,645	$ 42,811,109	$ 36,564,695
STRIDE 2 - Case No. 9468	$ 47,000,000	$ 38,000,000	$ -	$ -

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 20
Request Received: 06/02/2020
Response Date: 06/16/2020
Sponsor: David M. Vahos

Item No.: StaffDR20-21

Please indicate how many of each type of fleet vehicle is being replaced in each year of the plan. In responding please identify those that are leased and those that are purchased.

RESPONSE:

All planned replacement vehicles procured by BGE during the MYP Period expect to be purchased. The following table provides BGE's vehicle replacement plan by type for the MYP Period:

Vehicle Type	Dec - 2019 Fleet	Planned Replacements			
		2020	2021	2022	2023
Light Vehicles	870	89	119	46	37
Heavy Vehicles	420	40	29	53	37
Equipment	550	64	96	40	53
Total	**1840**	**193**	**244**	**139**	**127**

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 20
Request Received: 06/02/2020
Response Date: 06/16/2020
Sponsor: David M. Vahos

Item No.: StaffDR20-22

Please indicate what levels of contingencies are reflected in the forecasted capital and O&M spend by project for each year of the plan

RESPONSE:

The Company budgets contingency on a project by project basis. Projects in earlier phases of design or that are subject to more variability or change will typically have some level of contingency added by the project manager. When the projects go through the approval process this contingency is reviewed and approved by leadership; however, the Company does not have comprehensive reporting or tracking of the contingencies.

For information on budgeting, please see the Direct Testimony of Company Witness Vahos Section V. Budgeting Process (Part 2, pages 16-19)

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 22
Request Received: 06/02/2020
Response Date: 06/16/2020
Sponsor: Robert D. Biagiotti

Item No.: StaffDR22-09

Regarding Direct Testimony of Robert D. Biagiotti filed May 15, 2020:

Please indicate to what extent the Pay It Forward program is reflected in new business gas investment.

RESPONSE:

As indicated on page 4 of Company Exhibit RDB-1, the cost associated with the proposed Pay It Forward program grows to approximately $5 million in 2023. The amounts by year from 2020 through 2023 are the following:

2020 - $2 million
2021 - $3 million
2022 - $4 million
2023 - $5 million

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 22
Request Received: 06/02/2020
Response Date: 06/16/2020
Sponsor: Robert D. Biagiotti

Item No.: StaffDR22-15

Regarding Direct Testimony of Robert D. Biagiotti filed May 15, 2020:

With regard to New Business Gas Capital spend; please identify large capital projects included in each amount for each year of the plan. In responding, please identify the size of amount and potential load applicable to each such project.

RESPONSE:

Regarding New Business Gas Capital spend, cost applicable to investments for each year of the plan is described in Company Exhibit RDB-1, pages 16 – 18. Load is utilized to create a design estimate for each customer. However, exact load applicable to investments for each year of the plan is not available due to unknown variabilities with each customer's request and is subject to change at each stage of the customer's development process.

Examples of large gas projects greater than $1 million include but are not limited to:

- UPS - $2-$3M for 2020, and $1M-$2M for 2021
- Bainbridge - $1M-2M for 2021
- Port Covington - $900k for 2020, and $1.8M for 2021
- Trade Point Atlantic - $1.2M for 2020
- Middle River Depot - $240k for 2020 and $1.5M for 2021
- Merriweather - $2.4M for 2021

o Values are high level estimates subject to change from final design

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 22
Request Received: 06/02/2020
Response Date: 06/16/2020
Sponsor: A. Christopher Burton

Item No.: StaffDR22-26

Regarding Direct Testimony of A. Christopher Burton filed May 15, 2020:

Please provide information that supports the statistics in leak repairs for mains and services as noted in the testimony at pages 10 and 11.

RESPONSE:

Please refer to the table below for supporting data:

	2014	2015	2016	2017	2018	2019
Main Leaks	3,724	3,151	3,399	3,306	3,184	3,088
Service Leaks (excluding fitter leaks)	3,847	4,686	6,254	4,920	4,171	3,556
Open Leaks	1,271	1,647	1,057	472	959	520

In assembling the data for this response, BGE noted several minor inconsistencies in the statistics discussed in the Direct Testimony of Witness Burton (page 10, line 19, through page 11, line 5). This section should read as follows, with the corrected statistics (bolded):

> Yes. First, the quantity of leak repairs on gas mains has been trending downward, with a **3%** decrease between 2018 and 2019 alone. In fact, main leak repairs have decreased every year back to 2016 and are **17%** lower than they were at their height in 2014. For service leak repairs[1], BGE has also observed an annual decrease every year since their highest mark in 2016 – a **43%** reduction in that time span. Between 2018 and 2019 alone, service leak repairs decreased nearly **15%**. These reductions also accompany a reduction in the leak backlog of **46%** compared to 2018. Thus, not only did BGE have less leak repairs in 2019, the Company also carried over less leaks discovered in 2019 to be repaired in 2020.

[1] Service leak repair numbers do not include “fitter” leaks. Fitter leaks are leaks on above-ground equipment in the vicinity of the meter and are often plumbing-like in nature.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 22
Request Received: 06/02/2020
Response Date: 06/16/2020
Sponsor: A. Christopher Burton

Item No.: StaffDR22-28

Regarding Direct Testimony of A. Christopher Burton filed May 15, 2020:

Please indicate how the proposed spending by category shown in the table on page 17 compares to spending by year during the period 2017 through 2019.

RESPONSE:

See *Attachment 1* for 2017 and 2018.

See the table on page 17 for a presentation of 2019.

BALTIMORE GAS AND ELECTRIC
2017 & 2018 GAS CAPITAL EXPENDITURES
($ in Millions)

CAPITAL		2017 [1]		2018 [1]
Gas Capacity Expansion	$	8.7	$	15.0
Gas Infrastructure Modernization Program		128.0		136.7
Gas System Performance		45.9		80.8
Gas Corrective Maintenance - Capital		27.1		30.1
Grand Total	**$**	**209.7**	**$**	**262.6**

[1] To create the comparative view requested, the historic actual data 2017-2019 provided in this data request is based on our budgeting tool (and not the general ledger). There are certain system limitations within the budgeting tool, such as archiving of data, that may cause the dataset not to reconcile to the general ledger. For example, certain attributes when modified prospectively will impact the historic view of the data as well. All actuals data impacting the revenue requirement is sourced from the general ledger.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 23
Request Received: 06/03/2020
Response Date: 06/17/2020
Sponsor: Robert D. Biagiotti

Item No.: StaffDR23-10

Regarding Direct Testimony of Robert D. Biagiotti filed May 15, 2020:

With regard to Corrective Maintenance Capital spend shown in the table on page 14, please provide all parameters, assumptions and criteria used to derive the forecasting spending shown therein.

RESPONSE:

The Company builds capital and O&M budgets for spend at the project level. Each project has an owner who is responsible for building the budgeted spend based on the resources, materials, timeline, and specific work needed to complete the project. For further information on the Company's budgeting, please see pages 16 to 19 of Part 2 of the Direct Testimony of Company Witness Vahos. Capital projects follow an authorization process to evaluate and authorize projects. One of the primary goals of this process is to ensure that projects are properly developed, planned, reviewed and authorized by senior management before resources are expended. BGE and Exelon have a defined Delegation of Authority structure to ensure that, based on the level of project expenditures, the appropriate level of management has reviewed and authorized them. This process helps ensure that the projected project expenditures are reasonable. As projects progress in time through design, engineering and execution they are reviewed in order to maintain appropriate oversight over budgets and scope of work as they progress through their lifecycle. Project level problem statements and solutions are also provided in BGE's direct testimony detailing the problem that needs to be addressed and the solution that has been identified to address the problem.

In order to assure the appropriateness and reasonableness of our capital and O&M budgets, they are reviewed and approved by a Category Manager who is responsible for the overall execution of the spend and work included in their category, as well as by a Vice President Category Owner who has governance and oversight for the category as discussed in the Direct Testimonies of Company Witnesses Ajit Apte, Robert D. Biagiotti, A. Christopher Burton, Tamla A. Olivier, and David M. Vahos (Part 2). This spend is reviewed by the CFO and COO as a part of the annual budget approval process. Additionally, many projects that make up a significant portion of BGE's spend are subject to Commission review including, but not limited to, STRIDE, DIMP, TIMP, RM43 and reliability standards.

Further, as agreed to by the Public Conference 51 working group and as directed by the Commission in Order No. 89482, the 2019 historic test year serves to provide a baseline for the reasonableness of the budgeted spend in the MYP. 2019 actuals are reviewed by an independent auditor in order to provide assurance over their accuracy.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 43
Request Received: 06/22/2020
Response Date: 07/07/2020
Sponsor: Robert D. Biagiotti

Item No.: StaffDR43-46

For Project ID 60797: Outdoor Lighting Streetlight Installs, why do costs increase significantly from 2019 into 2020 and beyond?

RESPONSE:

Project 60797: Outdoor Lighting Streetlight Installs is lights owned by the customer and installed by BGE at the customer's request. The budget is based on historical trends and the increase into 2020 covers the estimated cost of large projects that extends over several years.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 45
Request Received: 06/22/2020
Response Date: 07/07/2020
Sponsor: A. Christopher Burton

Item No.: StaffDR45-09

Why does BGE's Gas capacity expansion investment, and specifically Project ID 60701: Reinforcement - Gas System Reinforcements, increase significantly in 2020 as compared to 2019 and then lower significantly in 2021 before rising again significantly in 2022 and 2023?

RESPONSE:

Project ID 60701 Gas System Reinforcements investments fluctuate year-to-year, depending on the anticipated annual needs to maintain adequate capacity on the gas distribution and transmission systems as well as to provide support to STRIDE efforts for lower pressure system conversions to higher pressure. In 2019, a major steel reinforcement project to prepare for STRIDE pressure conversion was postponed to allow the resources and spending to support the Main Replacement Program (Project ID 60666), resulting in lower spend in the Reinforcement program for the year. In 2020, other major reinforcement projects, as well as a portion of the delayed work, are required for BGE to maintain capacity and prepare for STRIDE work.

Moving forward in the MYP, BGE anticipates these similar larger reinforcement projects will be regularly needed as both growth occurs and STRIDE conversion work continues. The decrease in 2021 (compared to 2020) reflects both the anticipated needs for the year and allows for the longer lead time for design, engineering, permitting, and resourcing of the more challenging work.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 45
Request Received: 06/22/2020
Response Date: 07/07/2020
Sponsor: A. Christopher Burton

Item No.: StaffDR45-19

Please explain why BGE needs Project ID 58194: System Reliability - Gas Distribution and why the costs increase significantly from 2019 in 2020 and beyond. Please fully explain the rationale and standards used to justify this project as required by the MYP Filing Requirements.

RESPONSE:

Project ID 58194 System Reliability – Gas Distribution focuses on regions of the gas system with potential reliability concerns, which otherwise would not be resolved through other program work. The program addresses conditions such as one-way feed mains, single feed district stations (including those with obsolete equipment), inadequately backfed regions, and areas prone to flooding. By improving reliability to these vulnerable regions, the likelihood of large customer outages will be significantly reduced, BGE's operational flexibility increased, and the system will be more aligned to current standards for new systems (see GD203-3 Part IV of the Gas Distribution Standards – Engineering and Design included in the Company response to StaffDR45-06 as CONFIDENTIAL Attachment 1).

This project was new in 2019 and ramped up to the level spend shown in the MYP starting in 2020.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 45
Request Received: 06/22/2020
Response Date: 07/07/2020
Sponsor: A. Christopher Burton

Item No.: StaffDR45-22

Please cite the source of the requirements from PHMSA for inspection of transmission lines that are increasing which is the driver of Project ID 58539: Upgrades for Gas Transmission In-Line Inspection. What technology is BGE contemplating in developing its estimate of approximately $1.9M in 2023?

RESPONSE:

Requirements for inspection of transmission mains are outlined by PHMSA in Title 49 Part 192.710 of the Code of Federal Regulations (CFR). BGE is considering the use of "smart pigs" for in-line inspection. Please see the response to StaffDR45-20 for more information on in-line inspection tools.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 45
Request Received: 06/22/2020
Response Date: 07/07/2020
Sponsor: A. Christopher Burton

Item No.: StaffDR45-31

Please cite the standard that is driving Project ID 61212: Valve Replacement Program. How do the individual pressure control devices selected for replacement meet this standard? Please also explain the "lumpiness" in the 2019 - 2023 annual spends.

RESPONSE:

Project ID 61212: Valve Replacement Program is part of BGE's work to reduce overpressurization risks, including those on the low pressure system, as described in the response to StaffDR45-08. In most cases, the work is directly related to either Company engineering standards or the federal code. Specifically, Title 49 Part 192.195 -203 of the Code of Federal Regulations outlines requirement to prevent overpressurizations risks. In addition, BGE Gas Distribution Standards – Design / Construction Section GC502-03 Part VI discusses valves and control line requirements. (Please refer to the Company response to StaffDR45-06 CONFIDENTIAL Attachment 2.)

Finally, as a result of the incident in Merrimack Valley, Massachusetts, BGE believes it is prudent to begin installing additional overpressurization protection on its low pressure system district regulators. It is widely believed that PHSMA will be issuing a ruling that will require this layer of protection in the future as well. In 2020, BGE will begin to install either slam-shut or relief valve devices, as well as additional monitoring, to prevent such an event.

Project ID 61212 increases in spend in 2020 as result of the additional efforts being taken to prevent overpressurization as well as an increased pace of the work. Year-to-year fluctuations in the MYP period can be the result of various complexity in jobs as well as balancing this work with other resources throughout the gas portfolio.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 47
Request Received: 06/23/2020
Response Date: 07/08/2020
Sponsor: A. Christopher Burton

Item No.: StaffDR47-28

Please verify that the GIMP capital expenditures included by Mr. Burton in forecasted spend for the years 2021 through 2023 are not reflected in Plant in the development of the revenue requirement by Mr. Vahos.

RESPONSE:

GIMP capital expenditures, which are included in STRIDE, are reflected in Plant in the development of the revenue requirement by Mr. Vahos. STRIDE revenues are also included in the development of operating income and these revenues serve to offset the impact of the plant in rate base. For further information, please see Part 2 of the Direct Testimony of Company Witness David Vahos, pages 34-35.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 51
Request Received: 06/26/2020
Response Date: 07/13/2020
Sponsor: David M. Vahos

Item No.: StaffDR51-02

With regard to Training Capital Costs indicated in Project 60127, please explain the increase between 2019 and 2020. Please explain why costs are classified as capital rather than O&M.

RESPONSE:

The Training Capital Costs contained in Project 60127 support the development and creation of training assets, such as virtual reality hardware and software platforms. The increased spending between 2019 and 2020 reflects a move to production of non-classroom-based training assets. As these costs are in support of the development and creation of long-term hardware/software training assets, they are recorded as capital.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 51
Request Received: 06/26/2020
Response Date: 07/13/2020
Sponsor: David M. Vahos

Item No.: StaffDR51-05

Please provide a breakdown of BackOffice Costs reflected in Project 53369 by year over the plan.

RESPONSE:

As described in Part 2 of the Direct Testimony of Company Witness Vahos, Company Exhibit DMV-8 page 4, common costs attributable to electric transmission that have no impact on distribution rate base or MYP distribution rates account for 90% of the back office allocation spend over the MYP period. This is consistent with how common spend is captured throughout the Capital and O&M templates. Directly assigned transmission costs have been removed from the templates; however, those common costs that are not directly assigned to electric transmission (but are allocated to transmission) are included in these templates for consistency purposes. These costs are removed in the calculation of the MYP distribution revenue requirement. In the Company's responses to StaffDR41-01 and StaffDR41-02, BGE provides a view of Project 53369 by line of business for capital and O&M.

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 60
Request Received: 07/09/2020
Response Date: 07/23/2020
Sponsor: David M. Vahos

Item No.: StaffDR60-14

Please provide a workpaper that shows the development of the STRIDE revenues reflected for 2021 through 2023 that demonstrate that the STRIDE revenues so presented each year properly zero out the revenue requirement associated with STRIDE investments that are included in witness Vahos' gas revenue requirement for the years 2021 through 2023.

RESPONSE:

The STRIDE surcharge revenues included in the forecasted 2021-2023 MYP revenue requirement were calculated in the same manner and presented in the same revenue requirement exhibit format which are routinely included in the Company's annual STRIDE surcharge filing each year on November 1st. Please see *Attachments 1, 2 and 3* for the STRIDE surcharge revenues included in gas operating income for 2021-2023 which are subject to the STRIDE surcharge caps. These budgeted surcharge revenues are calculated using 6.45% after-tax rate of return and a 70.88% conversion factor, consistent with the Case No. 9610 settlement agreement and the current STRIDE 2020 surcharge.

Please also see *Attachments 4, 5,* and *6* for a calculation of the revenue requirement associated with the forecasted MYP STRIDE investments that are included in the gas revenue requirements for the years 2021-2023. This calculation is also consistent with the calculations included in the Company's annual STRIDE surcharge filings, except that the revenue requirement calculated in these attachments uses an after-tax rate or return of 6.61% and a conversion factor of 70.45% based upon the Company's request in this MYP proceeding.

Below is a summary of the STRIDE-related revenue requirements being requested by the Company in this MYP proceeding and the STRIDE surcharge revenues. The STRIDE surcharge revenues included in operating income do not completely offset the revenue requirement associated with the STRIDE investments in 2022 and 2023 due to the cap on the STRIDE surcharge revenues. To the extent the capped STRIDE surcharge revenues in 2022 and 2023 do not fully recover the STRIDE-related MYP revenue requirement due to the operation of the cap, the Company is requesting that the revenue requirement above the STRIDE surcharge cap be included in the MYP revenue requirements and the resulting distribution base rates approved by the Commission in this proceeding.

Additionally, there is a revenue requirement difference between the STRIDE surcharge revenues included in operating income and the revenue requirement associated with the MYP forecasted STRIDE investments due to a difference in the authorized rate of return underlying STRIDE surcharge revenues for planning purposes included in operating income (6.45%) compared to the rate of return being requested in the current MYP rate case (6.61%). For example, but for the difference in the authorized rate of return, the requested 2021 STRIDE revenue requirement in

MYP rates would be zero. Please note, however, that the impact of this revenue requirement difference becomes smaller if the Commission authorizes a rate of return that is less than what the Company has proposed in this proceeding. For example, if the Commission authorizes the current rate of return there will be no difference between the STRIDE surcharge revenues included in the MYP and the revenue requirement associated with the MYP forecasted STRIDE investments.

BALTIMORE GAS AND ELECTRIC			
SUMMARY OF STRIDE REVENUE REQUIREMENT VS STRIDE SURCHARGE REVENUES IN THE MYP			
MYP Revenue Requirement related to STRIDE Investments at Requested 6.61% ROR			
	2021	**2022**	**2023**
BOP	5.5	17.2	29.0
Services	2.2	7.0	11.4
	7.7	24.1	40.4
STRIDE Surcharge Revenues included in the MYP at 6.45% Authorized ROR	**7.5**	**23.2**	**23.4**
Remaining STRIDE Revenue Requirement Requested in MYP Rates	**0.2**	**0.9**	**17.0**

For further information please see Part 2 of the Direct Testimony of Company Witness Vahos on pages 34-35 and the Direct Testimony of Company Witness Fiery on pages 40-42.

BALTIMORE GAS AND ELECTRIC COMPANY
STRIDE SURCHARGE CALCULATION
CASE NO. 9610 ROR
GAS RIDER 16

2021 Surcharge

Total 2020 STRIDE Revenue Requirement	$7,500,000 A	Exhibit E Line BB

	CN 9610 Rev Requirement[a] B	Percent of Total Revenue Requirement C	Allocation of Revenue Requirement D=A*C	Forecasted Billing Determinants[b] E	Uncapped Monthly Surcharge F=D/E	Monthly Surcharge Cap G=Q	2021 STRIDE Monthly Surcharge H=(Min of F,G)	Revenues
Schedule D/GORR[1]	362,044,034	66.7%	$ 5,001,046	7,760,672	$ 0.64	$ 2.00	**$ 0.64**	**$ 4,966,830.08**
Schedule C	146,151,258	26.9%	2,018,840	532,736	$ 3.79	$ 11.61	**$ 3.79**	**$ 2,019,069.44**
Schedule IS	26,182,998	4.8%	361,675	1,013	$ 357.03	$ 1,053.83	**$ 357.03**	**$ 361,671.39**
Schedule ISS	2,473,001	0.5%	34,160	593	$ 57.61	$ 169.80	**$ 57.61**	**$ 34,162.73**
Schedule EG	6,101,227	1.1%	84,278	48	$ 1,755.80	$ 4,272.87	**$ 1,755.80**	**$ 84,278.40**
Total	**542,952,518**	**100%**	**$ 7,500,000**					**$ 7,466,012.04**

Calculation of Monthly Surcharge Cap

	CN 9610 Rev Requirement[a] I	CN 9610 # of Bills[c] J	CN 9610 # of Customers K=J/12	Rev Req per customer L=I/K	Rev Req per cust / Sch D Rev Req per cust M=L/(L for Sch D)	Schedule D Monthly Surcharge Cap[d] N	Monthly Surcharge Cap O=M*N
Schedule D/GORR[1]	$ 362,044,034	7,606,553	633,879	$ 571.16	1.00	$ 2.00	$ 2.00
Schedule C	$ 146,151,258	528,812	44,068	$ 3,316.49	5.81	$ 2.00	$ 11.61
Schedule IS	$ 26,182,998	1,044	87	$ 300,954.00	526.92	$ 2.00	$ 1,053.83
Schedule ISS	$ 2,473,001	613	51	$ 48,490.22	84.90	$ 2.00	$ 169.80
Schedule EG	$ 6,101,227	60	5	$ 1,220,245.40	2,136.43	$ 2.00	$ 4,272.87
	$ 542,952,518						

(a) Source: BGE Case No. 9610 Settlement Filing
- Schedule D: Sheet G-3 Column 8, Line 3
- Schedule C: Sheet G-4 Column 8, Line 6
- Schedule IS: Sheet G-5 Column 6, Line 7
- Schedule ISS: Sheet G-6 Column 6, Line 7
- Schedule EG: Sheet G-7 Column 6, Line 7

(b) Forecasted Billing Determinants for January-December 2020

(c) Source: BGE Case No. 9610 Settlement Filing
- Schedule D: Sheet G-3 Column 1, Line 1
- Schedule C: Sheet G-4 Column 1, Line 1
- Schedule IS: Sheet G-5 Column 1, Line 1
- Schedule ISS: Sheet G-6 Column 1, Line 1
- Schedule EG: Sheet G-7 Column 1, Line 1

(d) Source: Public Utilities Article § 4-210(d)(4)(i)(1), Md. Code Ann

(1) GORR = Grantors of Rights of Way

BALTIMORE GAS AND ELECTRIC COMPANY
STRIDE SURCHARGE CALCULATION
CASE NO. 9610 ROR
GAS RIDER 16

2022 Surcharge

Total 2020 STRIDE Revenue Requirement	$23,600,000 A	Exhibit E Line BB

	CN 9610 Rev Requirement[a] B	Percent of Total Revenue Requirement C	Allocation of Revenue Requirement D=A*C	Forecasted Billing Determinants[b] E	Uncapped Monthly Surcharge F=D/E	Monthly Surcharge Cap G=Q	2022 STRIDE Monthly Surcharge H=(Min of F,G)	Revenues
Schedule D/GORR[1]	362,044,034	66.7%	$ 15,736,623	7,823,810	$ 2.01	$ 2.00	**$ 2.00**	**$ 15,647,619.07**
Schedule C	146,151,258	26.9%	6,352,618	534,518	$ 11.88	$ 11.61	**$ 11.61**	**$ 6,205,751.83**
Schedule IS	26,182,998	4.8%	1,138,071	1,013	$ 1,123.47	$ 1,053.83	**$ 1,053.83**	**$ 1,067,529.79**
Schedule ISS	2,473,001	0.5%	107,492	593	$ 181.27	$ 169.80	**$ 169.80**	**$ 100,691.40**
Schedule EG	6,101,227	1.1%	265,196	48	$ 5,524.92	$ 4,272.87	**$ 4,272.87**	**$ 205,097.76**
Total	**542,952,518**	**100%**	**$ 23,600,000**					**$ 23,226,689.85**

Calculation of Monthly Surcharge Cap

	CN 9610 Rev Requirement[a] I	CN 9610 # of Bills[c] J	CN 9610 # of Customers K=J/12	Rev Req per customer L=I/K	Rev Req per cust / Sch D Rev Req per cust M=L/(L for Sch D)	Schedule D Monthly Surcharge Cap[d] N	Monthly Surcharge Cap O=M*N
Schedule D/GORR[1]	$ 362,044,034	7,606,553	633,879	$ 571.16	1.00	$ 2.00	$ 2.00
Schedule C	$ 146,151,258	528,812	44,068	$ 3,316.49	5.81	$ 2.00	$ 11.61
Schedule IS	$ 26,182,998	1,044	87	$ 300,954.00	526.92	$ 2.00	$ 1,053.83
Schedule ISS	$ 2,473,001	613	51	$ 48,490.22	84.90	$ 2.00	$ 169.80
Schedule EG	$ 6,101,227	60	5	$ 1,220,245.40	2,136.43	$ 2.00	$ 4,272.87
	$ 542,952,518						

(a) Source: BGE Case No. 9610 Settlement Filing
- Schedule D: Sheet G-3 Column 8, Line 3
- Schedule C: Sheet G-4 Column 8, Line 6
- Schedule IS: Sheet G-5 Column 6, Line 7
- Schedule ISS: Sheet G-6 Column 6, Line 7
- Schedule EG: Sheet G-7 Column 6, Line 7

(b) Forecasted Billing Determinants for January-December 2020

(c) Source: BGE Case No. 9610 Settlement Filing
- Schedule D: Sheet G-3 Column 1, Line 1
- Schedule C: Sheet G-4 Column 1, Line 1
- Schedule IS: Sheet G-5 Column 1, Line 1
- Schedule ISS: Sheet G-6 Column 1, Line 1
- Schedule EG: Sheet G-7 Column 1, Line 1

(d) Source: Public Utilities Article § 4-210(d)(4)(i)(1), Md. Code Ann

(1) GORR = Grantors of Rights of Way

BALTIMORE GAS AND ELECTRIC COMPANY
STRIDE SURCHARGE CALCULATION
CASE NO. 9610 ROR
GAS RIDER 16

2023 Surcharge

Total 2020 STRIDE Revenue Requirement	$39,500,000	A	Exhibit E Line BB

	CN 9610 Rev Requirement[a] B	Percent of Total Revenue Requirement C	Allocation of Revenue Requirement D=A*C	Forecasted Billing Determinants[b] E	Uncapped Monthly Surcharge F=D/E	Monthly Surcharge Cap G=Q	2023 STRIDE Monthly Surcharge H=(Min of F,G)	Revenues
Schedule D/GORR[1]	362,044,034	66.7%	$ 26,338,840	7,886,947	$ 3.34	$ 2.00	**$ 2.00**	**$ 15,773,894.70**
Schedule C	146,151,258	26.9%	10,632,559	536,300	$ 19.83	$ 11.61	**$ 11.61**	**$ 6,226,440.02**
Schedule IS	26,182,998	4.8%	1,904,823	1,013	$ 1,880.38	$ 1,053.83	**$ 1,053.83**	**$ 1,067,529.79**
Schedule ISS	2,473,001	0.5%	179,912	593	$ 303.39	$ 169.80	**$ 169.80**	**$ 100,691.40**
Schedule EG	6,101,227	1.1%	443,867	48	$ 9,247.22	$ 4,272.87	**$ 4,272.87**	**$ 205,097.76**
Total	**542,952,518**	**100%**	**$ 39,500,000**					**$ 23,373,653.67**

Calculation of Monthly Surcharge Cap

	CN 9610 Rev Requirement[a] I	CN 9610 # of Bills[c] J	CN 9610 # of Customers K=J/12	Rev Req per customer L=I/K	Rev Req per cust / Sch D Rev Req per cust M=L/(L for Sch D)	Schedule D Monthly Surcharge Cap[d] N	Monthly Surcharge Cap O=M*N
Schedule D/GORR[1]	$ 362,044,034	7,606,553	633,879	$ 571.16	1.00	$ 2.00	$ 2.00
Schedule C	$ 146,151,258	528,812	44,068	$ 3,316.49	5.81	$ 2.00	$ 11.61
Schedule IS	$ 26,182,998	1,044	87	$ 300,954.00	526.92	$ 2.00	$ 1,053.83
Schedule ISS	$ 2,473,001	613	51	$ 48,490.22	84.90	$ 2.00	$ 169.80
Schedule EG	$ 6,101,227	60	5	$ 1,220,245.40	2,136.43	$ 2.00	$ 4,272.87
	$ 542,952,518						

(a) Source: BGE Case No. 9610 Settlement Filing
- Schedule D: Sheet G-3 Column 8, Line 3
- Schedule C: Sheet G-4 Column 8, Line 6
- Schedule IS: Sheet G-5 Column 6, Line 7
- Schedule ISS: Sheet G-6 Column 6, Line 7
- Schedule EG: Sheet G-7 Column 6, Line 7

(b) Forecasted Billing Determinants for January-December 2020

(c) Source: BGE Case No. 9610 Settlement Filing
- Schedule D: Sheet G-3 Column 1, Line 1
- Schedule C: Sheet G-4 Column 1, Line 1
- Schedule IS: Sheet G-5 Column 1, Line 1
- Schedule ISS: Sheet G-6 Column 1, Line 1
- Schedule EG: Sheet G-7 Column 1, Line 1

(d) Source: Public Utilities Article § 4-210(d)(4)(i)(1), Md. Code Ann

(1) GORR = Grantors of Rights of Way

BALTIMORE GAS AND ELECTRIC
SUMMARY OF STRIDE REVENUE REQUIREMENT
Case No. 9645 Requested ROR

2021 Surcharge

ASSETS ELIGIBLE FOR TREATMENT AS TAX REPAIRS:

RATE BASE:		**Operation Pipeline**	**Services Program**	**Total**
A	Capital Expenditures Current Year	$96.6	$32.5	$129.0
B	Capital Expenditures- Cumulative	96.6	32.5	$129.0
C	Book Depreciation Rate	1.76%	3.54%	
*D = ((A * C)/12*11.5/2) + ((B - A) * C)*	Depreciation Expense- Book	$0.8	$0.6	1.4
E	Depreciation Reserve- Book	-0.8	-0.6	-1.4
F = B + E	Book Basis	95.8	31.9	127.7
G	Average Book Basis	47.9	16.0	63.8
H	Deferred Income Tax	-12.1	-4.0	-16.2
I = G + H	Average Rate Base	35.7	11.9	47.655
J	ROR (After Tax)	6.61%	6.61%	
*K = I * J*	Return on Rate Base	2.4	0.8	3.2
L	Conversion Factor	70.45%	70.45%	
M = K / L	Initial Revenue Requirement	3.4	1.1	4.5

ASSETS ELIGIBLE FOR MACRS TREATMENT:

RATE BASE:		**Operation Pipeline**	**Services Program**	**Total**
N	Capital Expenditures Current Year	$24.1	$8.1	$32.3
O	Capital Expenditures- Cumulative	24.1	8.1	$32.3
P	Book Depreciation Rate	1.76%	3.54%	
*Q = ((N * P)/12*11.5/2) + ((O - N) * P)*	Depreciation Expense- Book	$0.2	$0.1	0.3
R	Depreciation Reserve- Book	-0.2	-0.1	-0.3
S = O + R	Book Basis	23.9	8.0	31.9
T	Average Book Basis	12.0	4.0	16.0
U	Deferred Income Tax	0.0	0.0	0.0
V = T + U	Average Rate Base	11.9	4.0	15.924
W	ROR (After Tax)	6.61%	6.61%	
*X = V * W*	Return on Rate Base	0.8	0.3	1.1
Y	Conversion Factor	70.45%	70.45%	
Z = X / Y	Initial Revenue Requirement	1.1	0.4	1.5

COSTS TO RECOVER:				
AA	Operating Income Need	1.0	0.7	1.7

REVENUE REQUIREMENTS:				
BB = (M + Z + AA)	Revenue Requirement	5.5	2.2	7.7

BALTIMORE GAS AND ELECTRIC
SUMMARY OF STRIDE REVENUE REQUIREMENT
Case No. 9645 Requested ROR

2022 Surcharge

ASSETS ELIGIBLE FOR TREATMENT AS TAX REPAIRS:

RATE BASE:		**Operation Pipeline**	**Services Program**	**Total**
A	Capital Expenditures Current Year	$97.6	$34.3	$131.9
B	Capital Expenditures- Cumulative	194.2	66.7	$260.9
C	Book Depreciation Rate	1.76%	3.54%	
*D = ((A * C)/12*11.5/2) + ((B - A) * C)*	Depreciation Expense- Book	$2.5	$1.7	4.3
E	Depreciation Reserve- Book	-3.3	-2.3	-5.6
F = B + E	Book Basis	190.9	64.4	255.3
G	Average Book Basis	143.3	48.2	191.5
H	Deferred Income Tax	-38.4	-12.9	-51.3
I = G + H	Average Rate Base	104.9	35.3	140.186
J	ROR (After Tax)	6.61%	6.61%	
*K = I * J*	Return on Rate Base	6.9	2.3	9.3
L	Conversion Factor	70.45%	70.45%	
M = K / L	Initial Revenue Requirement	9.8	3.3	13.2

ASSETS ELIGIBLE FOR MACRS TREATMENT:

RATE BASE:		**Operation Pipeline**	**Services Program**	**Total**
N	Capital Expenditures Current Year	$24.4	$8.6	$33.0
O	Capital Expenditures- Cumulative	48.6	16.7	$65.2
P	Book Depreciation Rate	1.76%	3.54%	
*Q = ((N * P)/12*11.5/2) + ((O - N) * P)*	Depreciation Expense- Book	$0.6	$0.4	1.1
R	Depreciation Reserve- Book	-0.8	-0.6	-1.4
S = O + R	Book Basis	47.7	16.1	63.8
T	Average Book Basis	35.8	12.0	47.9
U	Deferred Income Tax	-0.3	0.0	-0.3
V = T + U	Average Rate Base	35.6	12.0	47.561
W	ROR (After Tax)	6.61%	6.61%	
*X = V * W*	Return on Rate Base	2.4	0.8	3.1
Y	Conversion Factor	70.45%	70.45%	
Z = X / Y	Initial Revenue Requirement	3.3	1.1	4.5

COSTS TO RECOVER:

AA	Operating Income Need	4.0	2.5	6.5

REVENUE REQUIREMENTS:

BB = (M + Z + AA)	Revenue Requirement	17.2	7.0	24.1

BALTIMORE GAS AND ELECTRIC
SUMMARY OF STRIDE REVENUE REQUIREMENT
Case No. 9645 Requested ROR

2023 Surcharge

ASSETS ELIGIBLE FOR TREATMENT AS TAX REPAIRS:

RATE BASE:		**Operation Pipeline**	**Services Program**	**Total**
A	Capital Expenditures Current Year	$101.5	$29.3	$130.7
B	Capital Expenditures- Cumulative	295.7	96.0	$391.7
C	Book Depreciation Rate	1.76%	3.54%	
*D = ((A * C)/12*11.5/2) + ((B - A) * C)*	Depreciation Expense- Book	$4.3	$2.9	7.1
E	Depreciation Reserve- Book	-7.6	-5.1	-12.8
F = B + E	Book Basis	288.1	90.8	378.9
G	Average Book Basis	239.5	77.6	317.1
H	Deferred Income Tax	-64.8	-21.1	-85.9
I = G + H	Average Rate Base	174.6	56.6	231.201
J	ROR (After Tax)	6.61%	6.61%	
*K = I * J*	Return on Rate Base	11.5	3.7	15.3
L	Conversion Factor	70.45%	70.45%	
M = K / L	Initial Revenue Requirement	16.4	5.3	21.7

ASSETS ELIGIBLE FOR MACRS TREATMENT:

RATE BASE:		**Operation Pipeline**	**Services Program**	**Total**
N	Capital Expenditures Current Year	$25.4	$7.3	$32.7
O	Capital Expenditures- Cumulative	73.9	24.0	$97.9
P	Book Depreciation Rate	1.76%	3.54%	
*Q = ((N * P)/12*11.5/2) + ((O - N) * P)*	Depreciation Expense- Book	$1.1	$0.7	1.8
R	Depreciation Reserve- Book	-1.9	-1.3	-3.2
S = O + R	Book Basis	72.0	22.7	94.7
T	Average Book Basis	59.9	19.4	79.3
U	Deferred Income Tax	-0.9	-0.2	-1.0
V = T + U	Average Rate Base	59.0	19.2	78.259
W	ROR (After Tax)	6.61%	6.61%	
*X = V * W*	Return on Rate Base	3.9	1.3	5.2
Y	Conversion Factor	70.45%	70.45%	
Z = X / Y	Initial Revenue Requirement	5.5	1.8	7.3

COSTS TO RECOVER:				
AA	Operating Income Need	7.0	4.3	11.3

REVENUE REQUIREMENTS:				
BB = (M + Z + AA)	Revenue Requirement	29.0	11.4	40.4

Case No. 9645
Baltimore Gas and Electric Co.
Response to Staff Data Request 66
Request Received: 07/17/2020
Response Date: 07/31/2020
Sponsor: David M. Vahos

Item No.: StaffDR66-02

In regard to BGE's response to Staff DR47-16 related to contingencies, please provide a breakdown of the capital and O&M contingency amounts included in Attachment 1 by Electric and Gas.

RESPONSE:

Please refer to *Attachment 1* for the capital and O&M contingency by Electric distribution and Gas distribution, including the Electric distribution and Gas distribution portion of common projects.

BALTIMORE GAS AND ELECTRIC COMPANY
MYP Capital Contingencies -Electric Distribution
($Millions)

Project	**2020(1)**	**2021(1)**	**2022(1)**	**2023(1)**
Large Infrastructure Projects				
59398: Clare Street Substation 115/34kV Substation	0.5	-	1.8	1.3
59399: Clare Street Substation 34kV Feeders	-	-	-	0.6
59403: Demo Westport #6 34kV Substation	-	-	-	0.9
60144: Loch Raven Substation	0.1	0.1	-	0.7
60295: Fitzell 115-13kV Substation	0.5	-	-	-
61742: Demo (below grade) Westport #8	-	0.7	-	-
60296: Highlandtown 34037 34034 Francis Scott Key	2.2	-	-	-
60696: Center 4261 4kV Conversion	0.2	-	-	-
61008 - Cedar Park to Waugh Chapel Wood Pole Line Replacement - Part D, Distribution	0.1	-	-	-
61104: Center 4260 4kV Conversion	0.1	-	-	-
61499: Clifton Park 4832 4kV Conversion	0.1	-	-	-
61500: Clifton Park 4836 4kV Conversion	0.2	-	-	-
61503: RM43 Woodbrook 4401, 4409 & 4416 4kV Conversion	0.3	0.3	-	-
61504: RM43 Woodbrook 4403, 4407 & 4410 4kV Conversion	0.4	-	-	-
61506: Woodbrook 4415 & 4418 4kV Conversion	0.5	-	-	-
62641: Sentient Underground Fault Indicators	0.1	0.1	0.1	0.0
62644: Sentient Overhead Fault Indicators	0.1	0.1	0.1	0.1
61377: Distribution Substation Security	0.2	-	0.2	0.2
59119: Center 13248 Collapsed Duct Bank Rebuild Section 1	0.1	-	-	-
66690: Center 13248 Collapsed Duct Bank Rebuild Section 2	0.1	-	-	-
58968: New Business Crain Highway Conway Road Gas Approach	-	-	-	-
58477: Severn River Bridge Main Replacement	-	-	-	-
59322: Spring Gardens Liquified Natural Gas (LNG) Boil Off Compressor	-	-	-	-
60080: Granite Pipeline-Gate Station to Lord Baltimore	-	-	-	-
61208: Gas Facility Security	-	-	-	-
Projects Less than $1M (Large Infrastructure)	0.1	0.1	0.1	0.1
Total Large Infrastructure Projects (Electric Distribution Only)	*5.6*	*1.4*	*2.2*	*3.9*
IT Projects				
54600: Business Intelligence & Data Analytics - Grid Domain IT	0.1	-	-	-
57113: EU Analytics AMI Capital IT	0.1	0.1	-	-
57345: Leased Line Optimization (LLO)	0.1	-	-	-
58584: EU Analytics Customer Project Two	0.2	-	-	-
59039: Customer Care and Billing Implementation	8.8	-	-	-
59877: BGE Distribution-Supervisory Control And Data Acquisition Lifecycle Upgrade	0.5	-	-	-
61401: Advanced Distribution Management System Implementation	0.5	0.5	0.6	0.5
61589: Load Settlement & Forecasting Deployment	0.2	0.2	-	-
61601: Single Connectivity Model	0.0	-	-	-
61616: Mobile Mapping Solution for Mobile Dispatch Implementation	0.9	0.9	0.9	-
64690: BGE PC 44 Rate Pilots	0.1	0.1	-	-
64692: Supplier Consolidated Billing - Case # 9461	0.1	0.4	0.1	-
64715: EU Customer Journey - I Sign Up And Move	0.2	-	-	-
64741: EU Core Geographic Information System Implementation (Electric/Gas)	0.2	0.1	0.4	0.0
64849: BGE-PHI Powerbase Implementation	-	0.2	0.1	-
Projects Less than $1M (IT Projects)	0.9	0.4	0.1	-
Total IT (Electric Distribution Only)	*12.9*	*2.9*	*2.1*	*0.6*
Total Capital Contingency -Large Infrastructure and IT Projects (Electric Distribution Only)	***18.4***	***4.3***	***4.2***	***4.4***

(1) May not sum due to rounding

BALTIMORE GAS AND ELECTRIC COMPANY
MYP Capital Contingencies -Gas Distribution
($Millions)

Project	2020(1)	2021(1)	2022(1)	2023(1)
Large Infrastructure Projects				
59398: Clare Street Substation 115/34kV Substation	-	-	-	-
59399: Clare Street Substation 34kV Feeders	-	-	-	-
59403: Demo Westport #6 34kV Substation	-	-	-	-
60144: Loch Raven Substation	-	-	-	-
60295: Fitzell 115-13kV Substation	-	-	-	-
61742: Demo (below grade) Westport #8	-	-	-	-
60296: Highlandtown 34037 34034 Francis Scott Key	-	-	-	-
60696: Center 4261 4kV Conversion	-	-	-	-
61008 - Cedar Park to Waugh Chapel Wood Pole Line Replacement - Part D, Distribution	-	-	-	-
61104: Center 4260 4kV Conversion	-	-	-	-
61499: Clifton Park 4832 4kV Conversion	-	-	-	-
61500: Clifton Park 4836 4kV Conversion	-	-	-	-
61503: RM43 Woodbrook 4401, 4409 & 4416 4kV Conversion	-	-	-	-
61504: RM43 Woodbrook 4403, 4407 & 4410 4kV Conversion	-	-	-	-
61506: Woodbrook 4415 & 4418 4kV Conversion	-	-	-	-
62641: Sentient Underground Fault Indicators	-	-	-	-
62644: Sentient Overhead Fault Indicators	-	-	-	-
61377: Distribution Substation Security	-	-	-	-
59119: Center 13248 Collapsed Duct Bank Rebuild Section 1	-	-	-	-
66690: Center 13248 Collapsed Duct Bank Rebuild Section 2	-	-	-	-
58968: New Business Crain Highway Conway Road Gas Approach	-	-	-	-
58477: Severn River Bridge Main Replacement	0.8	-	-	-
59322: Spring Gardens Liquified Natural Gas (LNG) Boil Off Compressor	0.3	-	-	-
60080: Granite Pipeline-Gate Station to Lord Baltimore	-	-	3.3	-
61208: Gas Facility Security	0.3	-	-	-
Projects Less than $1M (Large Infrastructure)	-	-	-	-
Total Large Infrastructure Projects (Gas Distribution Only)	*1.3*	*-*	*3.3*	*-*
IT Projects				
54600: Business Intelligence & Data Analytics - Grid Domain IT	-	-	-	-
57113: EU Analytics AMI Capital IT	0.1	0.0	-	-
57345: Leased Line Optimization (LLO)	0.1	-	-	-
58584: EU Analytics Customer Project Two	0.1	-	-	-
59039: Customer Care and Billing Implementation	4.6	-	-	-
59877: BGE Distribution-Supervisory Control And Data Acquisition Lifecycle Upgrade	-	-	-	-
61401: Advanced Distribution Management System Implementation	-	-	-	-
61589: Load Settlement & Forecasting Deployment	-	-	-	-
61601: Single Connectivity Model	0.0	-	-	-
61616: Mobile Mapping Solution for Mobile Dispatch Implementation	0.5	0.5	0.5	-
64690: BGE PC 44 Rate Pilots	0.1	0.1	-	-
64692: Supplier Consolidated Billing - Case # 9461	0.0	0.2	0.0	-
64715: EU Customer Journey - I Sign Up And Move	0.1	-	-	-
64741: EU Core Geographic Information System Implementation (Electric/Gas)	0.1	0.0	0.2	0.0
64849: BGE-PHI Powerbase Implementation	-	0.1	0.0	-
Projects Less than $1M (IT Projects)	0.4	0.2	0.1	-
Total IT (Gas Distribution Only)	*6.1*	*1.1*	*0.8*	*0.0*
Total Capital Contingency -Large Infrastructure and IT Projects (Gas Distribution Only	***7.4***	***1.1***	***4.1***	***0.0***

(1) May not sum due to rounding

BALTIMORE GAS AND ELECTRIC COMPANY
MYP O&M Contingencies Electric Distribution
($Millions)

Project	**2020(1)**	**2021(1)**	**2022(1)**	**2023(1)**
IT Projects				
59040: Customer Care and Billing (CC&B) Systems Implementation	2.9	-	-	-
59781: EU Geographic Information System (GIS) Data Quality	0.0	0.5	-	-
61423: Advanced Distribution Management System Implementation	0.2	0.0	0.0	0.1
61617: Mobile Mapping Solution for Mobile Dispatch Implementation - OM	0.1	0.3	0.3	-
64699: BGE Powerbase Implementation	-	0.1	0.0	-
64742: EU Core Geographic Information System (GIS) Implementation (Electric / Gas)	0.0	-	0.2	0.1
64686: Storm Critical Systems - IT Hardening and Remediation	0.4	-	-	-
Projects Less than $1M	0.2	0.1	0.0	-
Total IT Project O&M Contingency (Electric Distribution Only)	3.8	1.0	0.6	0.2

(1) May not sum due to rounding

BALTIMORE GAS AND ELECTRIC COMPANY
MYP O&M Contingencies Gas Distribution
($Millions)

Project	**2020**[1]	**2021**[1]	**2022**[1]	**2023**[1]
IT Projects				
59040: Customer Care and Billing (CC&B) Systems Implementation	1.5	-	-	-
59781: EU Geographic Information System (GIS) Data Quality	0.0	0.2	-	-
61423: Advanced Distribution Management System Implementation	-	-	-	-
61617: Mobile Mapping Solution for Mobile Dispatch Implementation - OM	0.1	0.2	0.2	-
64699: BGE Powerbase Implementation	-	0.1	0.0	-
64742: EU Core Geographic Information System (GIS) Implementation (Electric / Gas)	0.0	-	0.1	0.1
64686: Storm Critical Systems - IT Hardening and Remediation	0.2	-	-	-
Projects Less than $1M	0.1	0.0	0.0	-
Total IT Project O&M Contingency (Gas Distribution Only)	1.9	0.5	0.3	0.1

(1) May not sum due to rounding