

ORDER NO. 92666

In the Matter of Alternative Rate Plans or	*	BEFORE THE
Methodologies to Establish New Base	*	PUBLIC SERVICE COMMISSION
Rates for an Electric or Gas Company	*	OF MARYLAND

	*	Case No. 9618
	*	_____
Application of Baltimore Gas and	*	Case No. 9645
Electric Company for an Electric and	*	
Gas Multi-Year Plan	*	

ORDER ON MULTI-YEAR RATE PLANS LESSONS LEARNED

Before: Kumar P. Barve, Chair
Frederick H. Hoover, Jr., Commissioner
Bonnie A. Suchman, Commissioner
Odogwu Obi Linton, Commissioner
Ryan C. McLean, Commissioner

Issued: October 1, 2026

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I. INTRODUCTION

In Order No. 89226¹, the Maryland Public Service Commission (“Commission”) determined that it had authority to adopt alternative forms of rate regulations, to include multi-year rate plans (“MRPs”), pursuant to *Annotated Code of Maryland*, Public Utilities Article (“PUA”) §7-505(c). The Commission concluded that a properly designed MRP could provide advantages over traditional rate cases, including shorter regulatory lag, more predictable utility revenues and customer rates, spreading rate changes over several years, increased transparency into utility planning, and potentially lower regulatory burdens. By Order No. 89482, issued February 4, 2020, the Commission established a framework for a Multi-Year Rate Plan Pilot (the “MRP Pilot”).² It was the Commission’s determination that “undertaking a pilot will allow it to evaluate the use of MRPs in a controlled manner with minimal administrative burden and limited regulatory uncertainty for the initial utility seeking a pilot MRP.”³

Rather than immediately adopting MRPs statewide, the Commission chose a pilot approach involving the first Maryland utility to submit a qualifying MRP application. The Commission intended that the experience gained from the MRP Pilot would then inform future regulations.

In this Order, the Commission considers the oral and written comments presented

¹ Order No. 89226, *Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for An Electric Company or Gas Company*, PC 51, and *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for An Electric Company or Gas Company*, Case No. 9618, slip op. (Aug. 9, 2019), Maillog No. 226375 (“Order No. 89226”).

² Order No. 89482, *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*, Case No. 9618 (Feb. 4, 2020), Maillog No. 228451 (“Order No. 89482”).

³ Order No. 89482 at 2.

by various stakeholders participating in the Lessons Learned proceeding and assessing: (1) whether the MRP Pilot met its intended goals, (2) whether the MRP construct should be continued as structured, substantially modified or abandoned altogether as an alternative form of ratemaking in Maryland, and (3) if it is determined that the MRP construct should continue in some manner, what recommendations for improvements offered by various stakeholders should be further explored and examined for incorporation into the MRP construct for the future regulations.

II. PROCEDURAL HISTORY

In Order No. 89226, the Commission evaluated alternative forms of ratemaking and determined that a *properly constructed* multi-year rate plan (“MRP” or “MYP”)⁴ could result in just and reasonable rates and yield several benefits such as shortening the cost recovery period, providing more predictable revenues for utilities and more predictable rates for customers, spreading changes in rates over multiple years, and decreasing administrative burdens on regulators by staggering filings over several years.⁵ Subsequently, on February 4, 2020, the Commission issued Order No. 89482, which adopted a framework for an MRP Pilot program for the Maryland utility that would be the first to file an MRP application and volunteer to serve as the “Pilot Utility.”⁶ On February 5, 2020, Baltimore Gas and Electric Company (“BGE”) filed a letter⁷ with the Commission expressing its willingness and desire to serve as the Pilot Utility. On May 15, 2020, BGE

⁴ As discussed in previous orders, parties have used the acronyms MYP and MRP to refer to multi-year rate plans. This Order uses the terms interchangeably.

⁵ Order No. 89226 at 54.

⁶ Order No. 89482 at 1-2.

⁷ Maillog No. 228461.

filed its MRP application as the Pilot Utility, which initiated Case No. 9645.⁸

Following BGE's initial MRP application, the Commission's Technical Staff ("Staff") conducted discussions and filed a Lessons Learned Report focused on certain changes to the MRP application process, which the Commission addressed in Order No. 90401 (October 28, 2022).⁹ Since BGE's initial MRP application as the Pilot Utility, an MRP was also approved for the Potomac Electric Power Company ("Pepco") in Case No. 9655¹⁰ and through settlement for Delmarva Power & Light Company ("DPL") in Case No. 9681.¹¹ However, during the evidentiary hearing in Case No. 9655, Pepco witness McGowan acknowledged that even though Pepco was not the Pilot Utility, it agreed to be subject to the same standards and requirements established by the MRP framework in Order No. 89482.

COMMISSIONER LINTON: Good afternoon, Mr. McGowan. I have a couple of questions for the company. I'll start with your testimony and response to AOBA Witness Oliver in your rebuttal, I believe on page 24, where you noted—you're referencing Order 89482 where the Commission first established the MYP pilot concept. As part of that at the time we were looking for one company to serve as our pilot utility. As you know BGE filed fairly quickly after we issued the order accepting the opportunity to serve as the pilot utility. Mr. Oliver suggests that there's some lack of clarity whether or not this should be considered one of our pilots. We already had one and now we have a second one as a result of this filing. So just as an outset question and for purposes of the record. When BGE filed they voluntarily requested the opportunity to participate in the pilot. We didn't get a similar letter from PEPCO. There wasn't any kind of public statement stating that the company wanted to be held to all of the same standards and requirements. **So I guess by your testimony here today, is it fair to say that PEPCO is accepting**

⁸ Maillog No. 230267. Case No. 9645, *Application of Baltimore Gas and Elec. Co. for an Electric and Gas Multi-Year Plan*.

⁹ Maillog No. 230267.

¹⁰ Order No. 89868, *Potomac Elec. Power Co.'s Application for an Electric Multi-Year Plan*, Case No. 9655 (Jun. 8, 2021) ("Order No. 89868").

¹¹ Order No. 90445, *Delmarva Power & Light Co.'s Application for an Electric Multi-Year Plan* (Dec. 14, 2022) ("Order No. 90445").

all of the same standards and requirements of the pilot that were established from the beginning?

MR. McGOWAN: Yes, we are. It's our expectation that the Commission is establishing rules for multi-year rate plans what the regulations are and then there will be a lessons learned and then file regulations a couple years out. We believe that as companies filing multi-year rate plan before that occurs, that they're building on rules and decisions made by the Commission. So we opted to file our multi rate plan in a similar way as [BGE] did. We tried to align it to how the Commission had decided such that you can have consistency in the multi rate plans that are approved in the state.¹²

Further, the Commission noted in Order No. 89868 that “[d]espite the Commission’s desire for a “lessons-learned” analysis following the issuance of the BGE MRP Order, and the opportunity to develop regulations governing Alternative Form of Regulation (“AFOR”) utility multi-year plan requests, the MRP Pilot Order did not preclude the filing of the multi-year request made by Potomac Electric Power Company (“Pepco”) before the BGE MRP Order issued.”¹³ The Commission admonished that “unlike BGE’s MRP proposal, Pepco’s application was not the pilot. Therefore, the Commission [would] not reiterate verbatim its instructions from the BGE MRP Order. However, until MRP regulations have been drafted and promulgated, the Commission expects compliance with those instructions in all future MRP proposals.”

On January 1, 2024, in Order No. 90948, the Commission approved a second MRP for BGE in Case No. 9692.¹⁴ The Commission issued Order No. 92106 on December 22, 2025, which addressed BGE’s first MRP Rate Year Three Reconciliation (“RY3”), the final reconciliation regarding BGE’s initial MRP rate case and completing a full cycle of

¹² Hr’g. Tr., Case No. 9655 Vol. 1, 141:14–143:6 (Apr. 26, 2021) (emphasis added).

¹³ Order No. 89868 at 1-2.

¹⁴ Order No. 90948, *Baltimore Gas and Elec. Co.’s Application for an Electric and Gas Multi-Year Plan*, Case No. 9692 (Jan. 1, 2024) (“Order No. 90948”).

the Pilot Utility’s initial MRP.¹⁵ BGE’s second MRP concluded with the Commission’s issuance of Order No. 90948 in Case No. 9692.

On August 15, 2024, the Commission issued a Notice initiating this MRP Lessons Learned proceeding and seeking comments from stakeholders and other interested parties on how BGE’s first MRP fared relative to the goals and potential benefits discussed in Order No. 89226 and in comparison, to traditional ratemaking. The Notice established a procedural schedule that included an in-person legislative-style hearing that was held on October 15 and 16, 2024.¹⁶ Additionally, the Notice solicited comments from BGE, and other interested stakeholders or affected parties on various topics including, but not limited to, the following:

- (1) what, if any, appreciable improvements in State policy objectives have been achieved under the MRP compared to traditional ratemaking;
- (2) whether the potential shortened cost recovery period was achieved and its impact on customers and other aspects of the ratemaking process such as cost disallowance;
- (3) whether rate predictability was achieved and its impact relative to traditional ratemaking;
- (4) whether administrative burdens actually decreased on the Commission and other stakeholders;
- (5) whether greater transparency into capital spending and improvements in system reliability have been realized compared to standard ratemaking; and
- (6) whether more utility innovation and equitable risk distribution have been achieved relative to traditional ratemaking.

¹⁵ Order No. 92106, *Application of Baltimore Gas and Elec. Co. for an Electric and Gas Multi-Year Plan*, Case No. 9645 (Dec. 22, 2025) (“Order No. 92106”).

¹⁶ Maillog No. 311808, Errata to Notice Issued on Pilot MRP Lessons Learned, Case Nos. 9618 and 9645, (Aug. 20, 2024).

On September 16, 2024, Initial Comments were filed by the following parties: Maryland Energy Administration (“MEA”);¹⁷ Apartment and Office Building Association of Metropolitan Washington (“AOBA”);¹⁸ Pepco and DPL (collectively, “The PHI Companies”);¹⁹ International Brotherhood of Electrical Workers (“IBEW Local 410”);²⁰ BGE;²¹ Office of People’s Counsel (“OPC”);²² Office of Staff Counsel (“Staff”);²³ Constellation Energy Generation, LLC and Constellation Newenergy, Inc. (“Constellation”);²⁴ and WeaveGrid.²⁵

On September 25, 2024, the Commission issued a Notice providing for additional, in-person, legislative-style hearings in Case Nos. 9618 and 9645 to be held on Wednesday, October 16, 2024 and Thursday, October 17, 2024 at 10:00 a.m., if needed.²⁶

Several parties filed Reply Comments including BGE,²⁷ The PHI Companies,²⁸ Staff,²⁹ and OPC.³⁰ Additionally, several parties including Staff,³¹ The PHI Companies³² and BGE³³ filed slide presentations to be referenced and reviewed during the October 15 hearings.

¹⁷ Maillog No. 312339 (“MEA Initial Comments”).

¹⁸ Maillog No. 312344 (“AOBA Initial Comments”).

¹⁹ Maillog No. 312352 (“The PHI Companies Initial Comments”).

²⁰ Maillog No. 312357 (“IBEW Local 410 Initial Comments”).

²¹ Maillog No. 312358 (“BGE Initial Comments”).

²² Maillog No. 312359 (“OPC Initial Comments”).

²³ Maillog No. 312360 (“Staff Initial Comments”).

²⁴ Maillog No. 312361 (“Constellation Initial Comments”).

²⁵ Maillog No. 312595 (“WeaveGrid Initial Comments”).

²⁶ Maillog No. 312512.

²⁷ Maillog No. 312730 (“BGE Reply Comments”).

²⁸ Maillog No. 312731 (“The PHI Companies Reply Comments”).

²⁹ Maillog No. 312734 (“Staff Reply Comments”).

³⁰ Maillog No. 312737 (“OPC Reply Comments”).

³¹ Maillog No. 312988 (“Staff Slideshow Presentation”).

³² Maillog No. 313005 (“The PHI Companies Slideshow Presentation”).

³³ Maillog No. 313007 (“BGE Slideshow Presentation”).

On October 15 and 16, 2024, the Commission held a legislative-style hearing on the MRP Lessons Learned.

On December 13, 2024, the Commission received post-hearing briefs from AOBA;³⁴ MEA;³⁵ The PHI Companies;³⁶ OPC;³⁷ BGE;³⁸ and Staff.³⁹

On May 20, 2025, Governor Wes Moore signed into law, effective June 1, 2025, the Next Generation Energy Act (“NGEA”), which among other things added criteria that utilities must show to have an MRP plan approved. The new law also prohibited utilities from filing for the reconciliation of cost or revenue variances. As a result of the new law, the Commission issued a Notice of Opportunity to Update Briefs in light of NGEA.⁴⁰ Updated briefs were filed on or about September 5, 2025 by the following parties: AOBA;⁴¹ MEA;⁴² BGE and The PHI Companies;⁴³ OPC;⁴⁴ Staff;⁴⁵ the Maryland Energy Advocates Coalition (“MEAC”);⁴⁶ and Ceres, Inc.⁴⁷

On May 12, 2026, Governor Wes Moore signed into law, effective July 1, 2026, the Utility Reducing Energy Load Inflation for Everyday Families (RELIEF) Act, which among other things further modified the statute by stating explicitly that multi-year rate plans may have asymmetrical reconciliation of cost or revenue variances in favor of

³⁴ Maillog No. 314217 (“AOBA Final Brief”).

³⁵ Maillog No. 314231 (“MEA Initial Brief”).

³⁶ Maillog No. 314243 (“The PHI Companies Initial Brief”).

³⁷ Maillog No. 314246 (“OPC Initial Brief”).

³⁸ Maillog No. 314247 (“BGE Initial Brief”).

³⁹ Maillog No. 314248 (“Staff Initial Brief”).

⁴⁰ Maillog No. 321220.

⁴¹ Maillog No. 322148 (“AOBA Updated Brief”).

⁴² Maillog No. 322152 (“MEA Updated Brief”).

⁴³ Maillog No. 322155 (“Joint Exelon Utilities Updated Brief”).

⁴⁴ Maillog No. 322167 (“OPC Updated Brief”).

⁴⁵ Maillog No. 322169 (“Staff Updated Brief”).

⁴⁶ Maillog No. 322177 (“MEAC Comments”).

⁴⁷ Maillog No. 322184 (“Ceres Comments”).

customers. The RELIEF Act also imposed a time-limited prohibition upon forecasted test years and required the Commission to conduct further proceedings to determine if projected, hybrid, or fully-historic test years are in the best interest of ratepayers.

III. DISCUSSION & FINDINGS

A. MRP Goal Achievement Assessment

This section examines whether the current MRP framework and process met the Commission's intended goals as set forth in Order Nos. 89226 and 89482. It summarizes each party's assessment on whether the goals were met, any shortcomings discovered during the implementation of the MRP pilot and any recommended improvements to be considered should the MRP ratemaking model continue in the future.

1. Goal 1: Shortening the cost recovery period

a. *BGE*

BGE argues in its initial comments that the MRP process reduces regulatory lag and enhances insight into prudence, which provides a balanced risk-reward proposition for all stakeholders.⁴⁸ BGE asserts that “[t]he nature of historic test year ratemaking creates regulatory lag and uses it as a cost control stick for the utility;” and observes that by the rate effective period, test year costs are in the past.⁴⁹ In contrast, BGE contends that regulatory lag has been reduced under the pilot MRP, as rate base and operating income are based on forecasted values that align with the rate effective periods.⁵⁰ BGE argues that

⁴⁸ BGE Initial Comments at 17.

⁴⁹ *Id.*

⁵⁰ *Id.*

“[t]he MYP is structured to carefully balance the distribution of risk between utilities and customers—for example, construction work in progress is not included in rate base, which means that customers do not begin paying for utility investments until they are used and useful.”⁵¹

Further, BGE notes that contrary to the belief of some parties, the company has not earned more than its return on equity (“ROE”) under the MRP process. BGE indicated that “during the MRP pilot years of 2021-2023, the Company’s earned ROE for electric distribution and gas have been around 150 basis points below the authorized ROEs, a percent difference of 15%.”⁵² BGE also argues that the MRP’s reconciliation process acts as a check to ensure the Company will not over-earn its ROE by requiring the company to return any over-recovery of the allowed revenue requirement through a reconciliation rider to include carrying costs.⁵³ BGE points out that under the historic traditional ratemaking model “[i]f the Company earns more than its authorized ROE, it is not required to come in for a rate case and return the over-recovery to customers.”⁵⁴ Therefore, BGE argues that it is to the benefit of customers to allow the utility to use the MRP construct versus the historic ratemaking construct.

Additionally, BGE in conjunction with Pepco and Delmarva (together the “Joint Exelon Utilities”) argued that a properly structured MRP would be beneficial to the financial health of the utility and noted that Regulatory Research Associates (“RRA”), a subsidiary of S&P Global, raised the regulatory environmental ranking for Maryland following the

⁵¹ *Id.*

⁵² *Id.* at 17-18.

⁵³ *Id.* at 18.

⁵⁴ *Id.*

implementation of MRPs as progressive ratemaking to address regulatory lag.⁵⁵ BGE pointed out, however, that RRA has since downgraded Maryland's ranking three times and now views Maryland as having the most restrictive regulatory climate of any state in the U.S.

b. PHI Companies

The PHI Companies argue that “[j]ust and reasonable rates entail giving a utility an opportunity of earning its authorized rate of return as long as the utility is performing prudently.”⁵⁶ The PHI Companies contends that the MRP paradigm provides a utility with an improved opportunity to earn its rate of return (“ROR”) by reducing the regulatory lag associated with traditional historic test year (“HTY”) ratemaking.⁵⁷ In their joint initial comment, the PHI Companies indicated that the MRP construct as developed by the Commission provided the Companies the opportunity to recover their investments in the distribution system in a timelier manner because rates were set in a forward-looking manner.⁵⁸ The PHI Companies stated that by allowing the utility distribution system investments over a three-year period, the regulatory lag present with traditional HTY ratemaking has been reduced. They pointed out that in Case No. 9702, a response to Staff DR 1-10 revealed that “Pepco’s earned ROEs from the seven years leading up to the filing of its first MYP averaged 7.89%, while the earned ROEs from the three MYP rate years averaged 8.74%.”⁵⁹ Similarly, they noted that in a response to Staff DR 5-10 in Case No.

⁵⁵ Joint Exelon Utilities Updated Brief at 16-17.

⁵⁶ The PHI Companies Initial Comments at 6.

⁵⁷ *Id.*

⁵⁸ *Id.* at 6-7.

⁵⁹ *Id.* at 7, referencing Case No. 9702, *Potomac Elec. Power Co.’s Application for Adjustments to its Retail Rates for the Distribution of Electric Energy*.

9681, DPL's earned ROEs from 2011 through 2021 averaged 6.59%, while Rate Year 1 of DPL's first MRP showed an earned ROE of 10.73%, leading to a \$7.3 million over collection of revenue, which DPL is returning to customers over the August 1, 2024, to June 30, 2025, period.⁶⁰

In its initial comments, the PHI Companies argue that the traditional historic test year ratemaking model does not have an ingrained process that would allow over-earning to be returned to customers. They also pointed out that use of MRPs does not eliminate regulatory lag entirely nor does it guarantee that the utility will earn its authorized ROR.⁶¹

The PHI Companies argued that the improved opportunity for a utility to earn its authorized return has benefits for customers by permitting better credit metrics for the utility and lowering borrowing costs that become savings passed to customers when rates are set.⁶² Additionally, the PHI Companies claimed that the financial health of the utility provides better access to the credit markets, but cautioned that MRPs "do not create an environment where shareholder interests are favored to the detriment of customers."⁶³ The PHI Companies highlighted that the MRP construct does not prohibit the Commission or other stakeholders from challenging the investments made by the utility in the distribution system during an MRP.⁶⁴ Therefore, these investments under an MRP are still subject to the same risks of disallowance under the traditional HTY model.⁶⁵ The PHI Companies commented that the MRP provides the Commission and stakeholders with another tool not

⁶⁰ *Id.* at 7, referencing Case No. 9681, *Delmarva Power & Light Co.'s Application for an Electric Multi-Year Plan*.

⁶¹ The PHI Companies Initial Comments at 7.

⁶² *Id.*

⁶³ *Id.*

⁶⁴ *Id.* at 8.

⁶⁵ *Id.*

available with traditional HTY but without diminishing other aspects such as requiring that the utilities retain the burden of proof, cost recovery disallowances for distribution system investments that are determined not to be used and useful, and certain other customer protections.⁶⁶

Additionally, the PHI Companies asserted that MRPs improved their opportunity to earn their authorized return, claiming that “[a]llowing distribution system investments over a three-year period has helped the Companies reduce regulatory lag that would have been present in traditional [historical test year] ratemaking.”⁶⁷

c. OPC

OPC observes that while MRPs have shortened the cost of recovery period, that acceleration has encouraged utilities to make unnecessary capital investments that drive up customer rates.⁶⁸ OPC noted that “there is no evidence that reducing regulatory lag afforded any customer benefit.”⁶⁹ OPC explained that in traditional HTY ratemaking, regulatory lag serves as a constraint mechanism requiring a utility to wait until a subsequent rate change to begin recovering the costs of investments made after its most recent rate case and the investment has proven useful to customers.⁷⁰ Under the MRP construct, OPC points out that utilities include forecasted additions to plant in base rates which allows them to recover the costs of new capital investments contemporaneous to when they are incurred.⁷¹ OPC argued that “reductions in regulatory lag increase the likelihood that utilities—logically

⁶⁶ *Id.*

⁶⁷ The PHI Companies Initial Brief at 22-23.

⁶⁸ OPC Initial Comments at 17.

⁶⁹ *Id.*

⁷⁰ *Id.*

⁷¹ *Id.*

pursuing their private interests—will be over-aggressive in increasing their capital expenditures, to the point they are no longer cost-effective.”⁷²

OPC contends that utility profitability is driven by how well costs are controlled. Therefore, as costs rise a utility’s earned ROR falls and conversely as utility costs lower, the earned ROR increases. Accordingly, OPC claims that “regulatory lag incentivizes a utility to improve cost-effectiveness by enabling it to earn a higher return.”⁷³ OPC further concludes that reducing the regulatory lag period lessens the reward for containing costs and reduces the penalty for cost effectiveness. Thus, regulatory lag should be viewed as a key feature of standard ratemaking that forces utilities to constrain capital spending, and the MRP construct weakens this customer protection.⁷⁴

OPC also dismisses the claim that reducing regulatory lag causes utilities to advance State policy objectives in a way that cannot be done under standard ratemaking because investors are more willing to provide capital for policy-advancing investments under the MRP construct. OPC argues that the same level of security for investors is offered in standard ratemaking as the MRP and provided examples of the installation of smart meters and the development of EV charging stations to name a few. Moreover, OPC noted that it is unaware of any instance in which a utility has struggled to raise capital for such investments.⁷⁵

⁷² *Id.* at 18.

⁷³ *Id.*

⁷⁴ OPC Initial Brief at 18-19.

⁷⁵ *Id.* at 19.

d. Staff

In its initial comments to this filing, Staff notes that “unlike the standard rate proceeding, the MRP process in practice has resulted in customers having rate increases over each year of the rate effective period.”⁷⁶ As a result, Staff contends that “the experience of customers may be that the MRP process results in more rate increases than traditional ratemaking procedures.”⁷⁷ Further, Staff observes that by approving the levels and types of spending during the MRP rate-effective period and approving rates for a given revenue requirement, the MRP process may reduce the scope of any future prudency review to the consideration of whether the utility has diligently and prudently carried out its spending plans.⁷⁸

Staff contends that the achievement of a shortened cost recovery period is unclear and that the MRP format “transfers more risk from the utility to customers.”⁷⁹ Staff notes that the MRP includes projects that form the basis for rates that customers will pay on a year-to-year basis and that the utility submits detailed spending plans with varying levels of support. Staff commented that under the current structure it and other intervenors rely upon the asymmetric distribution of data regarding the spending plans to evaluate whether a utility may be adequate.⁸⁰ Staff observes that utilities provide “limited support for changes in projects either in the proposed project list or in the type and quantity of projects it seeks to recover.”⁸¹ This forces Staff and the other intervenors to query the utility about

⁷⁶ Staff Initial Comments at 5.

⁷⁷ *Id.*

⁷⁸ *Id.*

⁷⁹ *Id.*

⁸⁰ *Id.*

⁸¹ *Id.* at 6.

changes to the plan. Staff argued that it would be more advantageous if the utility were required to better support its spending plans including any modifications to its filed and approved plan.⁸² Staff further commented that currently the utility provides only a simple description of how the budgeted spending changed from the proposed spending which formed the basis of the rates. Staff noted that the utility does not unilaterally provide adequate support as to why its spending decisions are justifiable or reasonable; rather, Staff and the intervenors must interrogate the spending and decide whether the utility's spending decisions were appropriate.⁸³ Staff argued that this current MRP model is biased to the utility.⁸⁴

e. AOBA

AOBA acknowledges that the MRP construct has shortened the cost recovery periods for Maryland utilities but argues that the real question “is whether those shortened cost recovery periods are necessary, appropriate and justifiable from a ratepayer perspective.”⁸⁵ To that deeper question, AOBA argues that where large differences between budget and actual expenditures occur, “shortened cost recovery periods for utility operating expenditures that were not budgeted and capital projects that have not be[en] presented for review prior to the approval of rates for future periods are inappropriate.”⁸⁶ AOBA claims that shortened cost recovery lessens management accountability and diminishes incentives for utility cost control.⁸⁷ Further, AOBA contends that “absent

⁸² *Id.*

⁸³ *Id.*

⁸⁴ *Id.*

⁸⁵ AOBA Initial Comments at 6.

⁸⁶ *Id.*

⁸⁷ *Id.*

confidence in a utility's ability to forecast future expenditures with reasonable accuracy and *a priori* assessment of the prudence of expenditures, there can be no basis for an assumption that either a utility's budgeted or actual capital expenditures were prudent and no basis for accelerating cost recovery.”⁸⁸ Moreover, AOBA argues that “accelerated cost recovery of capital costs in the context of unconstrained capital spending is incompatible with the maintenance of affordable electric service for Maryland ratepayers.”⁸⁹

AOBA argues that Maryland statute mandates that the burden of proof in rate case proceedings lies with the utility and that the applicant must show a preponderance of the evidence that the proposed rates are just and reasonable.⁹⁰ AOBA notes that PUA § 4-201 requires that any public service company operating in Maryland “charge just and reasonable rates” and that such rate is defined, in part, as a rate that “fully considers and is consistent with the public interest.”⁹¹ AOBA argues that MRP's have provided utilities with shorter cost recovery periods while significantly impeding all parties, including the Commission, an ability to disallow costs based on a quantitative or reasonable basis.⁹²

f. Constellation

Constellation commented that “while the shortened cost recovery period may have been achieved, its impact on customers has been largely negative, resulting in higher bills and allowing utilities like BGE to recover forecasted expenditures without sufficient scrutiny.”⁹³ Constellation argues that the forecasting and reconciliation process during the

⁸⁸ *Id.*

⁸⁹ *Id.*

⁹⁰ *Id.* at 7.

⁹¹ *Id.*

⁹² *Id.*

⁹³ Constellation Initial Comments at 2.

MRP is less rigorous than the full prudence reviews in a traditional ratemaking case.⁹⁴ Arguing that the MRP allows for a simpler process via an adjustment rider for utilities to recover overspending as compared to traditional ratemaking, Constellation expresses concern that under MRP construct “there is no incentive for BGE [or any utility] to underspend” and the Commission’s ability to review and disallow imprudent spending has been reduced.⁹⁵

2. Goal 2: Enhanced transparency, proactive information sharing, and discovery

a. *BGE*

BGE asserts that more transparency into a utility’s planning process as a key part of the MRP construct was proven true.⁹⁶ BGE stated that the Company proactively provided a significant amount of documentation and details regarding the planning process that would not have been provided under HTY ratemaking. BGE noted that under the HTY model “stakeholders do not receive any information about utility investments until after they have been made.”⁹⁷ BGE stated that stakeholders do not have an opportunity to preview proposed work or give feedback prior to the utility making investment decisions. Additionally, BGE points out that with HTY ratemaking the focus is primarily on a singular year whereas with an MRP construct the utility provides around two years of actual cost data and up to three years of forecasted data which represents a big difference in terms of

⁹⁴ *Id.*

⁹⁵ *Id.*

⁹⁶ BGE Initial Comments at 8.

⁹⁷ *Id.* at 9.

cost and workplan information on economic drivers, trends and anomalies available to parties.⁹⁸

BGE also indicated that it supplements the cost data with project specific information and further substantiates its rate application with detailed testimony from Company operational witnesses as well as senior managers and executives. The Company argued that “[t]his unprecedented level of access to high-ranking company leaders, coupled with an immense amount of portfolio and project-specific justification, allowed stakeholders to become deeply familiar the Company’s plans, strategy, and goals for providing a safe, reliable, and resilient system for its customers in a cost-effective manner.”⁹⁹ Further, BGE remarked that such transparency is valuable to stakeholders to help increase their understanding of utility operations throughout this process, as well as giving stakeholders an opportunity to provide feedback including recommending the Company make changes to its plan, whether it be addressing specific projects, changing the pace of investments, *etc.*¹⁰⁰

BGE highlighted the change in volume of discovery that BGE has received in its first two MRP rate cases compared to previous historic rate cases. BGE asserted that the increased volume of discovery demonstrates a higher level of engagement with stakeholders.¹⁰¹

⁹⁸ *Id.*

⁹⁹ *Id.* at 9-10.

¹⁰⁰ *Id.* at 10.

¹⁰¹ *Id.*

Table 1:
Number of Data Requests in MRP Cases vs. Recent HTY Cases¹⁰²

Case Number	No. Data Requests (excl. subparts)	Average No. Data Requests (excl. subparts)
CN9692	2,230	
CN9645	2,286	
MYP Cases		2,258
CN9610	936	
CN9406	853	
CN9326	874	
CN9299	723	
CN9230	941	
Recent HTY Cases		865

BGE noted that in contrast to HTY ratemaking where witnesses primarily testified about ROE, the overall revenue requirement, cost of service and rate design, the MRP structure allows parties to gain more insight during discovery in the Company's forecasted plans, details on project prioritization, problem statement, solutions, benefits and other key information as well as available project authorization materials.¹⁰³ The Company also discussed other MRP-required annual compliance filings (*i.e.*, Annual Informational Filing) which provides revised forecasts for upcoming projects and associated costs. BGE argued that the MRP is intended to ensure that the Commission and parties can review and

¹⁰² *Id.* See Table 2: Number of Data Requests in MRP Cases vs. Recent HTY Cases.

¹⁰³ *Id.* at 11.

provide feedback on a utility's workplans including spending. The Company pointed to a few examples of how that occurred in its MRP rate cases such as the Commission reducing BGE's planned capital by \$175 million over 2021 to 2023 in Case No. 9645 and reducing capital spending by approximately \$500 million in Case No. 9692.

b. The PHI Companies (Pepco and Delmarva)

In its initial brief, the PHI Companies commented that “under the traditional ratemaking paradigm, the Commission reviews costs and investments by primarily looking backwards - using a historical approach - which means what utilities planned for future investments are typically not a major part of the rate case review process.”¹⁰⁴ Under the HTY ratemaking model, stakeholders have the ability to comment on utility capital spending because it is beyond the scope of the HTY base rate case proceeding.¹⁰⁵ Whereas, in Pepco's and DPL's MRPs, both the Commission and other stakeholders could gain greater insight, understanding and oversight into the utilities' capital investments and spending plan by providing the Companies' capital and operations and maintenance (O&M) plans in advance.¹⁰⁶ Pepco and DPL argue that the current MYP construct requires providing utility capital spending information before, during and after capital spending and distribution system investments are made.¹⁰⁷ The PHI Companies point out that the MYP minimum filing requirement “includes justification for distribution programs and detailed project level work plans *before* costs are incurred and supports the review of those investments *after* projects are completed to determine whether the investments were

¹⁰⁴ The PHI Companies Initial Comments at 12.

¹⁰⁵ *Id.* at 12-13.

¹⁰⁶ *Id.* at 13.

¹⁰⁷ *Id.*

prudent, and the money spent was well.” (emphasis added) Therefore, the PHI Companies argue that stakeholders under MYP construct are “given ‘two bites at the apple’ to review capital projects and investments.”¹⁰⁸

The PHI Companies noted that the MRP construct facilitates a process by which a utility provides detailed data to explain variances from budgeted amounts. The PHI Companies argued that this is beneficial because “budgets are just that—projections of amounts the utility will spend based on the best information at the time those budgets are developed.”¹⁰⁹ The PHI Companies noted that several exogenous factors come into play after a budget is developed that are beyond the utility’s control, particularly with projects with long lead times such as inflation, global crises that disrupt supply chains, and severe storms or other unforeseen incidents.¹¹⁰

The PHI Companies argue that “the MRP construct contemplates those situations where variances will occur and has safeguards in place, such as the reconciliation proceeding, to ensure that rates charged to customers remain just and reasonable.”¹¹¹ Unlike the HTY ratemaking model, the PHI Companies assert the MYP construct balances the needs of the Commission, stakeholders and customer in a more equitable manner.¹¹² Both companies highlight that the MYPs forward-looking approach helps the Commission and stakeholders gain insight and influence into utility capital plans and system investments that is not possible under the traditional HTY ratemaking paradigm.¹¹³ With

¹⁰⁸ *Id.*

¹⁰⁹ *Id.* at 14.

¹¹⁰ *Id.*

¹¹¹ *Id.* at 15.

¹¹² *Id.*

¹¹³ *Id.*

MRPs allowance of greater transparency into utility capital spending and system investments the PHI Companies' make more proactive investments, which has resulted in higher customer satisfaction as reported in customer satisfaction surveys.¹¹⁴

c. OPC

OPC conceded that as a general matter "MRPs afford stakeholders greater insight into utility planning than standard ratemaking," however, OPC argues that the increased transparency is largely illusory and have yielded few tangible benefits that outweigh the detrimental impacts to customers.¹¹⁵ First, OPC pointed out that the transparency "means little when the stakeholder review has little impact on the work a utility actually chooses to perform."¹¹⁶

Since the MRPs gives utilities the discretion to deviate from their proposed capital plans that were subject to stakeholder and Commission review, then the increased transparency becomes less meaningful.¹¹⁷ OPC acknowledged that the utilities retaining some discretion is appropriate with respect to safety and reliability projects as they are in the best position to determine the necessary work to be prioritized. However, for more discretionary capital investments, OPC argues that this discretion renders hollow the transparency benefits that advanced review of utility capital plans provides.¹¹⁸ To support its position, OPC pointed to AOBA witness Bruce Oliver's testimony in Case No. 9702 (Pepco's 2nd MRP) where Mr. Oliver testified that more than half of Pepco's capital

¹¹⁴ *Id.*

¹¹⁵ OPC Initial Comments at 24.

¹¹⁶ *Id.*

¹¹⁷ *Id.*

¹¹⁸ *Id.* at 25.

expenditures for Rate Years 1 and 2 in the company’s first MRP had significant departures from the capital budgets and project lists reviewed by the Commission and stakeholders in Case No. 9655 (Pepco’s 1st MRP). With such deviation, OPC argued that “there is little benefit to having ‘multiple bites at the apple’ to review and challenge the utility capital investments if that first ‘bite’ is not meaningful.”¹¹⁹

Second, OPC contends that the transparency provided in an advanced review of forecasted capital plans is limited. OPC noted that MRPs provide at most a three-year window into a utility’s plans and do not require utilities to provide additional visibility into longer-term plans that may be influencing the investment decisions. Without this context, OPC questions the Commission’s capacity to ensure that utilities’ short-term plans align with the long-term plans and that the long-term plans are being pursued cost-effectively and not piecemeal.

OPC also argued that the increased transparency benefit is limited by the utilities “heavily curating the information” provided in the MRP filings. OPC described the information as general program descriptions with very brief and high-level explanations of hundreds of projects which offer a very limited view of the utility’s short-term spending plans. With the level of information provided, OPC notes that stakeholders would still need to engage in significant discovery to better understand the context, justification, and reasonableness of the utility’s planned investments.¹²⁰

Next, OPC argued that the advanced approval of a utility’s forecasted plan shifts the burden to other parties to show that approved programs and projects were imprudent

¹¹⁹ *Id.*

¹²⁰ *Id.* at 26.

and reduces the risk of disallowance relative to HTY ratemaking where there is no pre-approval.¹²¹ Hence, OPC contends that the stakeholder transparency gains in the MRP are “outweighed by the consequences of ever-increasing base distribution rates driven by bloated utility investment plans” when the Commission could have used other measures to increase transparency within the HTY ratemaking construct.¹²²

d. Staff

Staff commented that in general, “MRPs provide greater transparency into utility spending plans versus traditional rate cases.”¹²³ Specifically, Staff noted that an advantage of an MRP rate case over an HTY case is that the MRP case requires the utility to file yearly proposed capital and O&M project lists prior to the implementation of those projects by the utility. Staff notes that the project list filing provides Staff and other stakeholders with insight into a utility’s planning processes and an opportunity to examine proposed programs including project purpose, implementation timing and estimated costs. Contrastingly in the HTY case, all the costs associated with capital and O&M projects presented by the utility in that rate case will have already been invested leaving the Commission and other stakeholders to evaluate the costs for prudence and not necessarily the projects forecasted purpose and the timing.¹²⁴

However, Staff indicated that the full transparency benefits of MRPs could be enhanced if utilities were required to demonstrate expected quantitative benefits associated

¹²¹ *Id.* at 28-29.

¹²² *Id.* at 29.

¹²³ Staff Initial Comments at 11.

¹²⁴ *Id.*

with proposed projects and investments.¹²⁵ In its brief, Staff recommended that should MRPs continue then filing requirements must be enhanced to better assist parties and the Commission in evaluating projects including requiring projects over a certain dollar threshold to include a listing of quantitative benefits that are expected, a breakdown of resources that are expected to be utilized and detailed written testimony in support of projects above a certain dollar threshold.¹²⁶ Staff recommended the following additional enhancements for better transparency: require a utility to explain changes between the original budget and those reflected in the current or updated Project List; require mid-year reports to identify project-list changes, and annual informational filings should identify completed projects, project deferrals including the reason for deferrals.¹²⁷ Staff argued that parties should not have to discover through extensive data requests why a utility's actual spending and projects differ from what the Commission originally approved.¹²⁸

Concerning system reliability, Staff commented that while it may be true that the current MRP format provides a greater look into the utilities' O&M and capital spending, it is less clear that the gained transparency results in greater improvements in the electric distribution system reliability over that which the HTY ratemaking model would have achieved.¹²⁹ Staff noted that the "requested transparency does not adequately shield non-utility parties from having to shoulder prudence risk, *etc.*"¹³⁰ Regarding the improvements in system reliability that have occurred, Staff credits the promulgation of RM43 regulations

¹²⁵ *Id.*

¹²⁶ Staff Initial Brief at 7.

¹²⁷ *Id.* at 8.

¹²⁸ *Id.* at 9.

¹²⁹ Staff Initial Comments at 10.

¹³⁰ *Id.*

more than the MRP process relative to traditional ratemaking.¹³¹ Staff stated that there is no evidence that MRPs have produced greater system reliability.¹³²

e. AOBA

AOBA disputes the claim that MRPs provide greater transparency into utility capital spending than traditional HTY ratemaking.¹³³ AOBA argues that the utility MRP reconciliation filings amply demonstrate that forecasted capital budgets for MRP rate years “constitute little more than ‘wish lists’ of projected expenditures that enable a utility’s parent company to meet its aggressive earnings growth projections.”¹³⁴ For the MRP rate cases, AOBA noted that reported actual capital expenditures have reflected large deviations between the composition of forecasted capital expenditures and the composition of the actual capital expenditures subsequently reported for those years.¹³⁵ With such dramatic deviations, AOBA contends that a utility’s representations of “[t]ransparency in capital planning hold little meaning.” Accordingly, AOBA comments that transparency does not lie in explanations of the processes for approving projects but in public presentation of actual supporting data and analysis.

AOBA uses Pepco’s two MRP cases to illustrate that the utility’s transparency claims are greatly diminished by the wide variation from forecasted budgets to actual expenditures. AOBA pointed out that for 2022, Pepco had \$183.3 million of budgeted costs for projects, but actually spent \$30.1 million, and had actual capital expenditures in 2022

¹³¹ *Id.* at 11-12.

¹³² *Id.*

¹³³ AOBA Initial Comments at 11.

¹³⁴ *Id.*

¹³⁵ *Id.*

of \$122.9 million for projects which it budgeted on \$68.1 million.¹³⁶ AOBA also noted that Pepco spent an additional \$104 million on projects that were not included in the forecasted capital plans presented to the Commission and other parties in Case No. 9655.¹³⁷ AOBA commented that the interim filings that update projects and budgets do not provide transparency in the approval process and offer no forum for parties to challenge the updates.¹³⁸ Therefore, AOBA argued that large deviations of forecasted capital project spending from a utility's initial budget to what is actually spent undermine claims that forecasted project lists improve transparency in a meaningful way.

Another transparency concern raised by AOBA was a utility's use of "Electronic Only Filings."¹³⁹ AOBA commented that this method has been used more frequently by utilities in the MRP rate cases and includes both supplemental information supporting utility applications and information provided through discovery. AOBA argued that some materials filed using this method are difficult to print, cannot be readily used as cross-examination exhibits and unnecessarily cumbersome.¹⁴⁰ AOBA indicated that such electronic only filing method may impede parties' efforts to dispute the accuracy and credibility of information in evidentiary proceedings, thus reducing transparency. AOBA noted that MRP rate cases with forecasted rates tend to involve more confidentiality issues that limit the ability of parties to openly discuss the influences of utilities' expectations regarding future financial results.¹⁴¹ AOBA observed that the confidentiality issues seem

¹³⁶ *Id.*

¹³⁷ *Id.* at 11-12.

¹³⁸ *Id.* at 12.

¹³⁹ *Id.*

¹⁴⁰ *Id.*

¹⁴¹ *Id.* at 13.

more prevalent in MRP rate cases which could further “retard the openness and transparency of key elements of information that are integral to Commission rate determinations.”¹⁴²

f. MEA

MEA recommends requiring utilities to demonstrate that their proposed rate-case expenditures are consistent with their filed distribution system plans.¹⁴³ It points to Illinois as an example, where utilities bear the burden of demonstrating that investments are prudent and reasonably necessary to implement an approved multi-year integrated grid plan.¹⁴⁴ MEA also recommended that if MRPs were continued, “more transparency, justification, and explanation of variances should be a baseline requirement.”¹⁴⁵ MEA recommends that Maryland adopt, at minimum, the principle that a utility must demonstrate how the spending requested in its rate case aligns with its distribution plan.¹⁴⁶

g. Constellation

Constellation argues that while MRP ratemaking was designed to provide increased visibility into capital investments and transparency in spending, the implementation fell short of this goal.¹⁴⁷ Constellation flagged forecasting accurately long-term capital spending and project timelines as a major issue which leads to discrepancies between projected and actual spending. Constellation argued that by only requiring program-level forecasts instead of detailed project-level data during the initial MRP filings, the

¹⁴² *Id.*

¹⁴³ MEA Initial Comments at 6.

¹⁴⁴ *Id.* at 5.

¹⁴⁵ *Id.* at 4.

¹⁴⁶ *Id.* at 6.

¹⁴⁷ Constellation Initial Comments at 4.

Commission and other stakeholders only have a limited ability to scrutinize specific investments.¹⁴⁸ As a result, the lack of detailed information impeded an examination of whether a utility made prudent and cost-effective investments in system reliability.¹⁴⁹ Constellation commented that “MRPs were expected to enhance transparency by requiring multi-year capital plans, but the actual implementation did not address this expectation.”¹⁵⁰ Instead, Constellation argued that reduced transparency and limited project-level data undermined efforts to ensure BGE’s investments align with public interest and regulatory goals.¹⁵¹ When compared to traditional HTY ratemaking, despite the potential for increased transparency under the MRP construct, Constellation contends that the transparency benefits have not been achieved.¹⁵²

3. Goal 3: Utilities able to make investments aligned to state policy goals and priorities

a. *BGE*

BGE argued that the MRP construct provides utilities with a structure to plan and execute on State policy initiatives in a forward-looking and more timely manner unlike the traditional HTY model which takes a backward-looking approach. As an example, BGE discussed how use of the MRP construct made it possible for the Company to include targeted initiatives, infrastructure plans and performance metrics in its second MRP proposal when the Maryland General Assembly established the new direction for the

¹⁴⁸ *Id.*

¹⁴⁹ *Id.*

¹⁵⁰ *Id.*

¹⁵¹ *Id.*

¹⁵² *Id.*

State’s clean energy transformation through the Climate Solutions Now Act (“CSNA”)¹⁵³ and the Zero Emission Vehicle Infrastructure Plan in 2022. BGE claims that moving forward these proposals under the traditional ratemaking model would have been challenging at best given significant regulatory lag and the after-the-fact review of investment decisions without any prior discussion.¹⁵⁴

BGE stated that other State policy goals such as electrification, decarbonization, electric vehicle (“EV”) initiatives, and grid transformation initiatives with greater distributed energy resources will undoubtedly require significantly increased levels of utility investment and the MRP framework is uniquely prepared to support such investment plans and execution. Namely, BGE touts that the MRP provides greater transparency into a utility’s workplans and provides the flexibility for the utility to adjust workplans underlying the forecasted expenditures.¹⁵⁵ BGE argues that “if policy or legislation is enacted midstream, the Company is able to adapt and adjust its work plans to support such changes” since the MRP framework allows the Company to communicate updates through both the annual capital and O&M Project List filings as well as the Annual Informational Filings.¹⁵⁶ Additionally, BGE noted that the MRP framework allows stakeholders to review the utility plans and investments in more depth by engaging in discovery and as needed, even engaging the Company in meetings and conversations regarding adjustments to the workplan.¹⁵⁷ BGE acknowledged that even though several of the policy driven new initiatives were ultimately not approved, the MRP framework itself made proposing these

¹⁵³ 2022 Maryland S.B. 528—Climate Solutions Now Act of 2022 (PUA §§ 7-801–7-804).

¹⁵⁴ BGE Initial Comments at 13.

¹⁵⁵ *Id.* at 13-14.

¹⁵⁶ *Id.* at 14.

¹⁵⁷ *Id.* at 13.

initiatives possible and thus they demonstrate a strong advantage of the MRP construct over traditional HTY ratemaking.¹⁵⁸

b. The PHI Companies

The PHI Companies argue that the MRP construct is better suited to support the State’s energy policy goals. The PHI Companies point to the CSNA, which calls for a 60% reduction in greenhouse gas emissions by 2031 relative to 2006 levels, and attaining a net zero economy by 2045.¹⁵⁹ The PHI Companies also cite the Distributed Renewable Integration and Vehicle Electrification (“DRIVE”) Act, which requires utilities to allow EVs with bidirectional chargers to connect to the distribution grid, building electrification, EV infrastructure, distributed energy resources, renewable interconnection and local decarbonization initiatives.¹⁶⁰ The PHI Companies argue that advancement of these policy objectives “has and will require careful and deliberate investments in the distribution system that must be planned and executed while considering the impact on customers.”¹⁶¹ Traditional HTY ratemaking primarily looks backward meaning that what utilities have planned for future investment are not considered part of the rate case review.¹⁶² Consequently, the Commission and stakeholders have no ability to review a utility’s planned capital spending and whether it aligns with or will achieve State policy goals because these capital spending plans are beyond the scope of a traditional HTY rate case.¹⁶³

¹⁵⁸ *Id.* at 14-15.

¹⁵⁹ The PHI Companies Initial Comments at 4.

¹⁶⁰ *Id.* at 4-5. *See* Distributed Renewable Integration and Vehicle Electrification (“DRIVE”) Act, 2024 Md. Laws, Ch. 475, S.B. 959.

¹⁶¹ The PHI Companies Initial Comments at 5.

¹⁶² *Id.*

¹⁶³ *Id.*

The PHI Companies noted that under the current MRP framework they provided detailed information regarding capital spending including the justification for distribution programs and detailed work plans before costs were incurred. The PHI Companies contend that the MRP framework provides an opportunity for the Commission and stakeholders to review and propose changes to the spending plans if there is disagreement over whether the proposed spending is the best way to achieve State policy goals.¹⁶⁴ Pepco and DPL state that this demonstrates how the MRP is superior to traditional ratemaking in the achievement of state policy goals.¹⁶⁵

c. OPC

OPC argues that the MRP construct has not advanced the State's policy objectives in any meaningful way, especially where it concerns greenhouse gas reduction, renewable energy, reliability and resiliency, efficiency, or reducing electricity imports as specified in PUA §§ 7-801 and 7-802.¹⁶⁶ OPC recommends that the Commission begin its evaluation of the impact of the MRP construct on the achievement of State policy by using the general objectives provided in PUA §§ 7-801 and 7-802 and require utilities to make a showing that these goals have been advanced and that the MRP uniquely enabled the outcome and the outcome was achieved in a cost-effective manner.¹⁶⁷

OPC commented that "the only real connection between State policy and MRPs is that in Order No. 89638, the Commission authorized utilities to propose performance

¹⁶⁴ *Id.*

¹⁶⁵ *Id.*

¹⁶⁶ OPC Initial Comments at 13.

¹⁶⁷ *Id.* at 14.

incentive mechanisms (“PIM”) in MRPs.”¹⁶⁸ OPC points out that the Commission’s order allows utilities to file PIMs using the traditional rate case, and MRPs are not afforded some unique ability to accommodate PIMs. Therefore, OPC notes that it is no surprise that MRPs have not advanced State policy objectives given the lack of any logical, practical, or legal connection.

Additionally, OPC argues that the MRPs have proven an inappropriate forum for some new policy initiatives and offered for example BGE’s and Pepco’s electrification plans in Case No. 9692 and 9702, respectively. BGE highlighted that in striking BGE’s plan the Commission noted “it is prudent and consistent with past precedent for the Commission to consider major new policy proposals in a separate docket rather than in a base rate case, where the parties and the Commission are required to address a multitude of issues in a constrained time frame.”¹⁶⁹ OPC also points out that while BGE proposed a number of PIMs in its second MRP in the name of reducing greenhouse gas emissions, the Commission rejected them all.¹⁷⁰ OPC noted that the Commission expressed concerns about BGE’s proposed PIMs and found that the PIMs failed to accelerate policy goals beyond the utilities’ capability.¹⁷¹ OPC argues that not only have MRPs failed to advance State policy goals, “but the Commission itself found that the utilities’ attempts to do so through the MRP were inadequate.”¹⁷² OPC concludes that under the MRP construct utilities have proposed more capital spending on distribution feeders, substations, pipes

¹⁶⁸ *Id.* at 14-15.

¹⁶⁹ *Id.* at 15.

¹⁷⁰ *Id.*

¹⁷¹ *Id.* at 15-16.

¹⁷² *Id.* at 16.

and capacity expansion, but there is no evidence that the spending has led to achieving State policy.¹⁷³

d. Staff

Staff comments that one of the goals of the MRP framework was to aid in achieving State policy objectives such as electrification, renewable energy development, gas pipeline replacements, new customer solutions, grid resiliency and other State goals.¹⁷⁴ As discussed above, Staff also noted that within the MRP framework, PIMs were contemplated as a way to encourage utilities to advance these policy objectives. However, Staff points out that no approved MRP has included an approved PIM. Therefore, Staff indicated that it is unclear whether the criteria to obtain an approved PIM is limiting progress within MRPs to advance State policy in comparison to traditional HTY ratemaking.¹⁷⁵

Staff's assessment is that it is unclear whether the MRP model has done anything to move State policy goals forward. Staff stated that the Commission certainly discussed providing incentives to advance certain measures, but no approved MRP included the ability to earn incentives for advancing these State interests or policy goals. Consequently, Staff finds that it is unclear whether the MRP process has successfully promoted State policy goals forward beyond traditional ratemaking.¹⁷⁶ In fact, Staff stated that normally policy objectives are addressed outside of base rate proceedings and pointed to Case No. 9692 when Staff and other stakeholders argued that the various proposed electrification

¹⁷³ *Id.*

¹⁷⁴ Staff Initial Comments at 3.

¹⁷⁵ *Id.*

¹⁷⁶ *Id.* at 4.

measures should be considered in future electrification proceedings and not the MRP. Staff concluded that although it was anticipated that the MRP construct would further State policy goals, in practice, it has not materialized.¹⁷⁷

e. AOBA

AOBA argues that the MRP framework has not appreciably improved the furtherance of State policy goals. In fact, AOBA argues that many of the initiatives relied upon by Maryland utilities to demonstrate their support for the State policy objectives, are at best peripheral to overall utility expenditures and revenue requirements and have no dependence upon the existence of an MRP.¹⁷⁸

AOBA disputes utilities' claims that MRPs are necessary to advance Maryland climate, electrification, reliability, or resilience objectives. AOBA sees no persuasive evidence that MRPs advance State policy more effectively than traditional HTY ratemaking.

f. MEA

In its initial comments, MEA stated that while it appreciates that the MRP construct allowed intervenors and parties an opportunity to review (and reject) some of BGE and Pepco's proposed electrification plans in their respective rate cases before ratepayer money was spent, arguably, other Commission proceedings also provide opportunities for review into how utilities are aligning with State climate goals.¹⁷⁹ Specifically, MEA uses EmPOWER filings as an example that should provide some window into details now that

¹⁷⁷ *Id.*

¹⁷⁸ AOBA Initial Comments at 5.

¹⁷⁹ MEA Initial Comments at 4.

the plans include the State’s greenhouse gas reduction requirements.¹⁸⁰ MEA also mentioned that the utility’s distribution system planning process ultimately approved by the Commission in PC 44 offers another opportunity and should also be integrated into a rate case whether traditional or an MRP.¹⁸¹ Therefore, as currently structured, MEA contends that MRPs are not necessary to advance State energy policy.

MEA recommends that the Commission examine a new Illinois statute as instructive for potential integration of a utility’s distribution plan into an MRP framework. MEA explained that in Illinois utilities bear the burden of demonstrating that investments are prudent and reasonably necessary to meet the requirements of the utility’s approved Multi-Year Integrated Grid Plan.¹⁸² MEA recommends that the Commission, at a minimum, require in rate cases that a utility demonstrate how its spending aligns with the utility filed distribution plan.

Additionally, MEA encouraged the Commission to revisit PIMs using lessons-learned from other states. For example, MEA noted that the Illinois legislature found that its previously enacted PIMs and performance-based formula rates had not been “sufficiently transformative in urgently moving electric utilities toward the State’s ambitious energy policy goals” and “may have resulted in excess utility spending and guaranteed profits without meaningful improvements in customer experience, rate affordability, or equity.”¹⁸³ However, in 2021 the Illinois legislature, among other things, instructed utilities to present PIMs in eight broad categories, subject to review for efficacy.

¹⁸⁰ *Id.*

¹⁸¹ *Id.*

¹⁸² *Id.* at 5, *citing* 220 ILCS 5/1-108.18.

¹⁸³ MEA Initial Comments at 5.

MEA indicated that the results of the legislative reforms were pending but could be instructive and help the Commission develop meaningful performance metrics that stretch utilities to incorporate the State’s policy goals.¹⁸⁴

Going forward, MEA argues that merely having a view into the utilities proposed electrification plans before ratepayer money is spent under the MRP framework is not enough. If MRPs are allowed to continue, MEA argues that utilities “should provide an easy and understandable cross reference to how future plans and forecasts relate to the state needs to incorporate distribution system planning, how gas and electric utilities integrate, assure resource adequacy, and address climate requirements under state legislative mandates such as the Climate Solutions Now Act, the DRIVE Act, and others.”¹⁸⁵

g. WeaveGrid

WeaveGrid expressed support for the ratemaking frameworks like the MRP that encourage utility investment in safe, reliable, clean and innovative electric systems. WeaveGrid commented that MRPs “can support this focus on the future by aligning strategic priorities between utilities, customers, and regulators, leading to the development of a smarter, stronger, and cleaner energy future.”¹⁸⁶ WeaveGrid noted that the path to achieving net-zero emissions is both long and complex and requires input from a diverse group of stakeholders.¹⁸⁷ WeaveGrid argued that “without the MRP process, utilities will

¹⁸⁴ *Id.*

¹⁸⁵ MEA Brief at 9.

¹⁸⁶ WeaveGrid Initial Comments at 1.

¹⁸⁷ *Id.*

be left to decide what work to do without input from voices that could help inform, up front, the optimal approach to infrastructure and programmatic investments.”¹⁸⁸

WeaveGrid also noted the MRP process can bring important benefits for customers through enabling utilities to better plan for and invest in a system that is changing at an unprecedented rate and offered as an example inclusion of EV adaptation and electrification plans in BGE’s second MRP.¹⁸⁹ WeaveGrid views the MRPs as reinforcing Maryland's commitment to be a leader in leveraging new distributed energy resources, as articulated through legislation such as the DRIVE Act.¹⁹⁰

h. Constellation

Constellation acknowledges that the Commission introduced MRPs to enhance State policy objectives, including grid modernization and clean energy adoption, by offering utilities a predictable revenue framework for long-term investments.¹⁹¹ However, Constellation argues that “BGE’s MRP has fallen short of its goals, proving ineffective in enhancing transparency, predictability, and regulatory efficiency beyond traditional ratemaking.”¹⁹²

Furthermore, Constellation describes the framework as flawed and failing to deliver on its promises, which in Constellation’s view only worsened existing issues, to the detriment of all stakeholders involved. Constellation recommends that the Commission should incorporate more rigorous mechanisms for evaluating utility forecasts and capital

¹⁸⁸ *Id.*

¹⁸⁹ *Id.* at 2.

¹⁹⁰ *Id.*

¹⁹¹ Constellation Initial Comment at 1-2.

¹⁹² *Id.* at 2.

investments to ensure they meet state objectives.¹⁹³ Constellation notes that “despite the potential benefits, there is a significant gap between anticipated and realized outcomes when aligning utility investments with state goals.”¹⁹⁴

4. Goal 4: Less administrative burden

a. *BGE*

BGE acknowledges the MRP construct is more intense and involves greater transparency into utility planning information which naturally corresponds with increased effort required to review and comment on the material.¹⁹⁵ However, BGE argues that the administrative burdens of MRPs should be compared to those inherent in traditional HTY rate cases filed on at least an annual basis. Accordingly, BGE contends that “*the level of effort associated with a MRP once every three years needs to be compared with the alternative of a new rate case filing every year (or more frequently)*.”¹⁹⁶ In this context, BGE argues that stakeholders would litigate an MRP application for approximately 10 months within a 36-month period, compared with approximately 21 months under annual historic test year rate cases.¹⁹⁷ Further, BGE commented that even though MRPs contain a reconciliation component, that feature has commonly been used in other Maryland rate proceedings and would not add any more administrative burden.

BGE notes that part of the lessons it expects stakeholders will collectively learn should the Commission move forward with MRPs is how to make the process more

¹⁹³ *Id.*

¹⁹⁴ *Id.*

¹⁹⁵ BGE Initial Comments at 16-17.

¹⁹⁶ *Id.* at 16 (emphasis in original).

¹⁹⁷ BGE Initial Comments at 16.

efficient in order to maintain and enhance benefits while also further alleviating administrative burdens. BGE also pointed out that the legislature, in recognition of the additional focus required to litigate an MRP, modified the procedural schedule to add 90 days to provide parties with additional time to conduct discovery and the Commission with additional time to determine the best outcome for customers.¹⁹⁸ The Company maintains its openness to continuing to enhance its MYP supporting materials to provide the parties further ease in reviewing its workplans. BGE concludes that MRPs provide more information and stakeholder involvement but reduce the aggregate burden associated with repeated base-rate cases.¹⁹⁹

b. The PHI Companies

The PHI Companies argued that MRPs by their very nature, decrease the amount of rate cases that utilities must file.²⁰⁰ Highlighting that they are “multi-year” plans, the PHI Companies note that inherently the utilities do not have to file an application to change rates yearly. Pepco also acknowledged that the legislature extended the time to review MRPs, or other alternative forms of regulation, beyond the seven months that the Commission has to review traditional rates to ten-months. The PHI Companies comment that ten months is ample time to fully prosecute and review the proposed rate change, and will occur only once every three years (if the MRP is constructed for three years) as opposed to potentially a single rate case each year.

¹⁹⁸ *Id.* at 17, *citing* 2022 Maryland S.B. 131/H.B. 228—Public Service Commission—Rate Suspension Proceedings and codified in PUA § 4-204(b)(2)(ii)(authorizing the Commission to extend the 180-day rate suspension period set for standard rate cases (up to an additional 90 days if the filing is for an alternative form of ratemaking)).

¹⁹⁹ BGE Initial Comments at 16

²⁰⁰ The PHI Companies Initial Comments at 10.

Furthermore, the PHI Companies praise the MRP framework's flexibility in terms of the structure of a rate filing as it relates to the length of the MRP.²⁰¹ As an example, Pepco's second MRP was cited where it proposed a three-year, nine-month MRP to help stagger rate case filing. Though this proposal was not accepted, Pepco argues that this demonstrates that MRPs can not only decrease the frequency of rate filings, but also be utilized to alleviate resource burdens for stakeholders. Finally, the PHI Companies reject the argument that annual informational and reconciliation filing increase the administrative burden of MRPs.²⁰² The PHI Companies note that the prudency reviews for Rate Years one and two in Case No. 9655 were incorporated into subsequent rate proceedings rather than requiring an entirely separate proceeding.²⁰³

c. OPC

OPC strongly disagrees with the proposition that the MRP ratemaking construct has reduced the administrative burden on the Commission and the other stakeholders. To the contrary, OPC argues that "MRP litigation is far more resource-intensive than litigating a standard rate case, requiring parties to review more complex applications and undertake significant discovery under a compressed timeframe."²⁰⁴ OPC points out that "after a utility's first MRP, each subsequent MRP requires parties to review five years of actual and planned expenditures: the utility's actual investments during the first two years of the prior MRP must be reviewed for prudency, while three years of forecasted capital investments for the company's pending MRP are reviewed for contemporaneous recovery

²⁰¹ *Id.* at 11.

²⁰² *Id.*

²⁰³ *Id.* at 11-12.

²⁰⁴ OPC Initial Comments at 21.

in going-forward rates.”²⁰⁵ OPC argues that the scope of this review is far more extensive than the traditional HTY rate case and parties only have an additional three months beyond what is permitted in a traditional rate case. OPC also notes that the extensive review of sorting through hundreds of projects must be done *before* engaging in discovery. OPC highlighted Staff’s request that the Commission postpone consideration of Pepco’s second MRP (Case No. 9702) as evidence of the heavy logistical and resource burdens that MRPs impose on parties.²⁰⁶

OPC concludes that “no evidence demonstrates that the administrative burdens imposed by MRPs are lighter than standard ratemaking burdens.”²⁰⁷ Rather, OPC stated its experience dictates that MRP cases have increased administrative burdens for stakeholders and are far more resource-intensive and burdensome than standard rate cases.²⁰⁸

d. Staff

One of Staff’s strongest critiques of the MRP framework is found in this area. Staff argues that “[t]he administrative burdens, compared with standard rate making, have not been eased through the MRP format.”²⁰⁹ In a traditional rate case, with the final order all issues are litigated and done. Under an MRP construct, Staff contends that parties must delve into thornier issues about the scope, cost, reasonableness of projects and must evaluate whether they were changed, scrapped or executed as authorized by the Commission’s Order.

²⁰⁵ *Id.*

²⁰⁶ *Id.* at 22.

²⁰⁷ *Id.* at 23.

²⁰⁸ *Id.*

²⁰⁹ Staff Initial Comments at 8.

Staff noted that in Order Nos. 89226 and 89482, reduced administrative burden on regulators was a benefit the Commission hoped to achieve by implementing MRPs; however, Staff asserted, “That goal has not come to fruition.”²¹⁰ Staff stated that the MRP construct requires numerous filings and review beyond the initial rate case, including project lists, informational filings, interim reconciliations and a final reconciliation. Staff contrasts this with a traditional rate case, where the parties review a defined test year and the proceeding largely concludes following the Commission’s decision.²¹¹ Staff argues that in an MRP rate case the burden is increased when the information that Staff requires to conduct its review is not provided in the initial filing including quantitative benefits.

Additionally, Staff comments that “[a]bsent a utility voluntarily providing this information, Staff is required to send out several rounds of data requests to obtain this vital information through the discovery process” which increases the administrative burden and shifts the burden of proof to Staff and other parties to defend their recommendations.²¹² Staff also notes that additional complexity arises from billing-determinant forecasts, reconciliations, annual informational filings, cost-of service analysis, and rate design.

Staff concludes that its administrative burden has increased with the MRP process.²¹³ However, it recognizes that there are several factors that may affect this, including the schedule of filings under an MRP, the number of companies with approved MRPs, and the available workforce.

²¹⁰ *Id.* at 9.

²¹¹ *Id.*

²¹² *Id.*

²¹³ *Id.* at 10.

e. AOBA

AOBA comments that the very nature of MRPs require greater efforts from the Commission, parties and other intervenors to examine and determine different sets of rates over multiple years into the future. OPC acknowledged that the legislature extended the Commission's review time but critiqued whether time added is sufficient given the complexity of the MRP filing.²¹⁴

AOBA argues that unlike traditional HTY ratemaking based largely on historic costs, MRPs require parties to evaluate multiple future years of forecasts, assumptions, analytics and project justifications.²¹⁵ AOBA contends that such reviews are difficult and time consuming.²¹⁶ Further, AOBA notes that no corresponding increase in resources has been provided to assist the Commission or other stakeholders with evaluating the additional detailed information. AOBA argues that the “magnitude of the tasks faced by other parties to pursue claims of imprudence is particularly onerous when **the utility is the holder of all relevant detail regarding its expenditure decisions** and the Commission has provided no guidance as to what constitutes prudence in a utility's capital and operating expenditure decisions.”²¹⁷ AOBA concludes that MRPs have failed to reduce regulatory burden.

f. MEA

MEA also rejects the premise that MRPs have reduced regulatory burden. It noted that based on the MRPs filed to date, Staff, OPC, intervenors, and the Commission have had to perform a substantial amount of additional work to understand utility reconciliation

²¹⁴ AOBA Initial Comments at 9.

²¹⁵ *Id.*

²¹⁶ *Id.*

²¹⁷ *Id.* at 10 (emphasis in original).

filings. For example, MEA pointed to BGE Case No. 9692 when Staff changed a proposed disallowance recommendation only after BGE supplied additional explanations through multiple rounds of data requests. MEA argued that the utility's initial filing should have contained adequate explanations and justification, rather than forcing other parties to obtain essential information through discovery.

Thus, MEA reaches a conclusion similar to Staff, OPC, and AOBA that: MRPs have not demonstrated that they reduce regulatory burden.

g. Constellation

Constellation comments that the MRP was designed to reduce the administrative burden of traditional ratemaking which required utilities to file for rate increases regularly and led to time-consuming and resource-intensive proceedings. Constellation notes that the MRP was expected to both decrease the frequency of rate case filings and to streamline the process by allowing utilities to set rates for multiple years in advance which purportedly would allow the Commission and stakeholders to focus on long-term planning and oversight rather than frequent rate case reviews.

Constellation concedes that there has been slight reduction by spreading rate changes over multiple years and fewer rate case filing, however, “[the MRP] has not fully eliminated these burdens due to several challenges” including the introduction of increased complexity of implementation, the need for detailed forecasting, and continuous adjustments require significant resources.²¹⁸ Additionally, Constellation points out that the Commission reviews are still required to ensure rate increases are just and reasonable, that

²¹⁸ Constellation Initial Comments at 3.

utilities explain when projected spending is inconsistent with actual expenditures. As a result, Constellation concludes that the MRP has not provided a significant reduction in the administrative workload.²¹⁹

5. Goal 5: Predictability of rates

a. *BGE*

BGE argues that the MRP did exactly as it was intended to do with respect to providing more predictable and transparent.²²⁰ BGE noted that this is a key benefit of the MYP construct because it allows the Commission, customers, and parties knowledge in advance when a company will be presenting their next rate case filing for review and when those rates will be effective.²²¹ BGE contrasts this with traditional ratemaking, where stakeholders cannot know whether the utility will file another rate case in one year or several years.²²² Therefore, BGE contends that the actual experience from Case No. 9645 shows, MRPs provide the Commission with the most flexibility to ensure rates are implemented in a more gradual manner.²²³

BGE highlights the COVID-19 period as an example of MRP flexibility. The Commission used offsets so customers experienced no net bill increase in 2021, extended additional offsets into 2022, and then discontinued them for 2023 as circumstances changed.²²⁴ BGE argues that this demonstrated the Commission's ability under an MRP to make rate increases more gradual and respond to changing customer circumstances.

²¹⁹ *Id.*

²²⁰ BGE Initial Comments at 7.

²²¹ *Id.*

²²² *Id.*

²²³ *Id.*

²²⁴ *Id.* at 8.

b. The PHI Companies

The PHI Companies argue that rate predictability is a significant benefit achieved with the MRP pilot. They stated that their “customers will know the rates they will pay in each year of the MYP, as these rates are visible and transparent in the Delmarva Power and Pepco tariffs.”²²⁵ The PHI Companies contend that a corollary benefit is that rate increases are spread out over multiple years, achieving gradualism that mitigates the impact of a sharp increase.²²⁶ The PHI Companies argue that knowing when the increase in your utility bill will occur and the magnitude of the dollar amount empowers customers to effectively plan their household budgets.²²⁷ The Companies noted that under the traditional HTY ratemaking model customers would not have this information.

Additionally, the PHI Companies argue that MYPs make it easier to accelerate tax benefits or other credits to customers to mitigate rate increases. The PHI Companies use as an example the Commission’s approved acceleration of tax benefits in Case Nos. 9645 and 9655 due to economic effects of the pandemic and denied approval of those tax benefits in Case No. 9702 because it deemed those offsets were not needed.²²⁸ The PHI Companies stated that from the utilities’ standpoint, the MYP structure provides predictable and steady revenue over a three-year period, with preestablished rates for that period visible to customers, and the flexibility to financially enable an acceleration of tax benefits that the Commission previously determined would take 20 years to return to customers.²²⁹

²²⁵ The PHI Companies Initial Comments at 9.

²²⁶ *Id.*

²²⁷ *Id.*

²²⁸ *Id.* at 9-10.

²²⁹ *Id.* at 10.

c. OPC

OPC acknowledges that under the MRP construct rates are more predictable in the sense that customers can see the extent to which their bill will increase in subsequent years.²³⁰ However, OPC argues that customers are less concerned with rate predictability than with rate stability. OPC argued that with the MRP, a residential customer may know how much their distribution rate will change over the next three years but that information is of little value given the month-to-month variability in factors that affect the customer's monthly bill.²³¹ OPC contends that ratepayers would benefit more from stable rates and Maryland's rates under the MRP construct have hardly been stable.²³² OPC noted that "[i]n each of BGE, Pepco, and Delmarva's MRPs, distribution rates have risen annually" and from a customer's perspective it does not matter whether the yearly increase is a result of an MRP or a traditional HTY rate case.²³³

Furthermore, OPC points out that under both the MRP and the traditional HTY model, the Bill Stabilization Adjustment ("BSA") is used to adjust distribution rates on a monthly basis to ensure that utilities earn no more or no less than the target revenue per customer. OPC argues that these regular adjustments create uncertainty in a customer's bill which undermines the purported "predictability."²³⁴ Therefore, OPC concludes that "given the impact of the BSA, MRPs are no better than standard ratemaking at assuring predictable utility revenues."²³⁵

²³⁰ OPC Initial Comments at 19.

²³¹ *Id.* at 20.

²³² *Id.*

²³³ *Id.*

²³⁴ *Id.*

²³⁵ *Id.* at 21.

d. Staff

Staff notes that with the MRP process, distribution rates are set by a schedule for the next three years which may provide some predictability regarding annual costs to the customers, but the predictability is undermined by the reconciliation process which can significantly alter rates.²³⁶ Staff also points out that relative to traditional HTY ratemaking, the MRP process has no effect on the predictability of other potential changes to a customer's total bill such as electricity commodity prices, transmission costs, purchase gas adjustments, renewable energy requirements, taxes and assessments.²³⁷

Staff acknowledged that there is some power in customers knowing rates for as long as three prospective years. Staff argued that the fact rates can change at the end of each MRP rate year creates a real question about the stability rate concept.²³⁸ Staff suggested that the Commission should consider adjusting the model such that additional revenue can be obtained up to a certain point. Staff concludes that rate predictability of MRPs is not something that a customer could rely on given all the other sources of uncertainty that still impact net volumetric rates for Maryland customers.²³⁹

e. AOBA

AOBA expressed skepticism that MRPs provided rate predictability for customers. In fact, AOBA argues that the most predictable result of the MRP framework is that rates will not decrease.²⁴⁰ As currently structured with the forecasted budgets and the ability for

²³⁶ Staff Initial Comments at 7.

²³⁷ *Id.*

²³⁸ *Id.*

²³⁹ *Id.*

²⁴⁰ *Id.* at 8.

utilities to change the composition of operating expenditures and capital projects without robust prudence, AOBA argues that utilities have little incentive to reduce costs and operate more cost-effectively.²⁴¹ As a result, AOBA contends consumers are greatly disadvantaged with rate volatility. Additionally, AOBA points out that MRPs may be subject to large reconciliation adjustments, the magnitude and timing of which customers cannot readily anticipate.²⁴² Further, AOBA notes that consumers already face other adjustments such as the BSA and other rate surcharges and the MRP-related reconciliation adjustments exacerbate the uncertainties. Therefore, AOBA concludes the notion that MRPs enhance predictability of rates is misleading at best.²⁴³

f. MEA

MEA argues that contrary to expectation MRPs do not achieve rate stability in Maryland.²⁴⁴ Instead, MEA comments that there appears to have been a continuous increase in budget forecasts between MYPs and actual utility expenditures. MEA highlights BGE as an example citing data Staff presented in Case No. 9645, where Staff asserted that BGE, in its 2020 MRP, forecasted a 2023 budget of \$445 million, and increased that budget to \$602 million just two years later in its next MRP, then ultimately reported an actual spend of \$645 million during 2023.²⁴⁵ MEA also cites OPC's assertion that BGE's 2023 reconciliation showed average variances of 115% for electric capital expenditures and 177% for O&M expenditures.

²⁴¹ *Id.*

²⁴² AOBA Initial Comments at 8.

²⁴³ *Id.*

²⁴⁴ MEA Initial Comments at 2.

²⁴⁵ *Id.*

MEA concludes that this level of variances undermines the goal of giving customers more predictable and gradual rate changes over a multi-year period. MEA recommended that at a minimum the Commission should consider a variance test or other cost containment cap if it moves forward with MRPs in the future.²⁴⁶

g. Constellation

Constellations argued that while the MRP was designed to offer more stable and predictable rates based on projected expenditures over multiple years, the Commission's BGE MRP rate decision demonstrates that theory does not prove bear out. Constellation points out that the Commission's decision to approve an increase of just under \$408 million in rate increases over three years in Case No. 9692 resulted in a first-year average monthly increase of approximately \$4.08 for residential electric customers and \$10.43 for residential gas customers.²⁴⁷ Constellation acknowledged that these increases were expected to decrease in subsequent years, yet it argues the initial hikes "demonstrate that the MRP did not mitigate potential for significant cost increases and fluctuations."²⁴⁸ As a result, Constellation argues that such increases demonstrate that simply scheduling rate increases over multiple years does not necessarily make them stable and affordable. Additionally, Constellation argues that the reconciliation process within the MRP discourages utilities from reducing operational and maintenance costs and capital spending between rate cases, which exacerbates the rate volatility issue and harms customers.²⁴⁹ Constellation suggested that the reconciliation process creates a moral-hazard problem

²⁴⁶ *Id.* at 2-3.

²⁴⁷ Constellations Initial Comments at 3.

²⁴⁸ *Id.*

²⁴⁹ *Id.*

because utilities may have less incentive to control O&M and capital expenditures when variances can later be recovered.

Constellation notes that compared to traditional ratemaking BGE's MRP was intended to reduce rate volatility and provide a more predictable rate path.²⁵⁰ However, Constellation argues that the significant first-year increases and the concerns raised about the reconciliation process suggest that the MRP has not achieved its goals. Constellation suggests that this highlights the need for adjustments to improve predictability while ensuring fair and reasonable rates for consumers.²⁵¹

6. Goal 6: Utility Innovation and Equitable Risk Distribution

a. *BGE*

BGE claims that without the MRP construct, the Company would not have had the same ability to put forth as many new and innovative proposals as it did during this pilot MRP period.²⁵² Specifically, BGE referenced the following proposed programs that likely would not have been put forth without the MRP construct – the use of accelerating tax benefits to offset rate increases during the initial pilot period, the performance incentive mechanism and associated metrics, resiliency plan, blue sky vegetation management pilot program, grid communication/fiber initiative, and customer electrification plan, which were all designed to support and advance State policy goals for electrification, safety, reliability and resiliency.²⁵³

²⁵⁰ *Id.*

²⁵¹ *Id.*

²⁵² BGE Initial Comments at 21.

²⁵³ *Id.*

BGE argues that the MRP process provides parties with much greater information to assess both actual and proposed investments, including the opportunity to recommend cost disallowances and adjustments to future spending plans, thus increasing risks to utilities. Therefore, BGE concludes that the MRP structure distributes risk appropriately, with the reconciliation ensuring customers pay no more than a utility's prudently incurred costs and with carrying costs only applying to refunds as a customer benefit.²⁵⁴

b. The PHI Companies

The PHI Companies spotlighted that in Order No. 89226, the Commission called out certain drawbacks in the traditional HTY rate case such as “a failure to equitably distribute risk, limited capabilities to monitor costs, regulatory lag, and potential restrictions on innovations.”²⁵⁵ In contrast, the PHI Companies note that the Commission selected the MRP as an alternative form of ratemaking because it would ensure just and reasonable rates while balancing the interest of utilities, ratepayers and State policy goals.

The PHI Companies argue that “the Commission struck the appropriate balance in addressing the concerns about being able to monitor costs, regulatory lag and incentivizing utility innovation while equitably distributing risk” by adopting the MRP reconciliation process.²⁵⁶ Moreover, the PHI Companies pointed out that to ensure utilities retained the risks of improper forecasts and to encourage cost control the Commission adopted an asymmetrical method for returning over and under collections of prudent expenditures.²⁵⁷ The PHI Companies argue that the Commission correctly determined this approach

²⁵⁴ *Id.*

²⁵⁵ PHI Companies Initial Comments at 16.

²⁵⁶ *Id.*

²⁵⁷ *Id.*

“equitably balanced risks between the utilities and customers, since it put the risk of inaccurate forecasts on utilities and provided a strong incentive for utilities to develop accurate forecasts and plan appropriately to stay within the authorized revenue requirement.”²⁵⁸ Pepco also contends that the MRP construct encourages utilities to propose innovative programs and highlighted Pepco’s smart inverter program in its second MRP in Case No. 9702. The PHI Companies argue, unlike MRPs, that under a traditional HTY the pace of innovative program investments responsive to support State policy goals would be slower.²⁵⁹

c. OPC

OPC noted that although innovation generally means “the introduction of something new” and characterized as beneficial, it does not mean that what is new is necessarily in the public interest.²⁶⁰ OPC stated that the “question before the Commission in this proceeding is whether the MRP structure has motivated the State’s electric utilities to innovate in ways that further the objectives on which the Commission has requested comment in this proceeding.”²⁶¹

OPC argues that there is no indication that utility innovation has improved because of MRPs and points out that Order No. 89226 provided no benchmarks of what “innovation” was by the Commission that MRPs would foster.^{262 263} OPC also highlighted that utility innovation is fostered in a number of ways that do not involve ratemaking or

²⁵⁸ *Id.* at 17.

²⁵⁹ *Id.* at 18.

²⁶⁰ OPC Initial Comments at 29.

²⁶¹ *Id.* at 29-30.

²⁶² *Id.* at 30.

²⁶³ *Id.*

depend on accelerated cost recovery and provided examples of EmPOWER programs enabling energy efficiency improvements, the pilot program in battery energy storage, and transportation electrification programs. OPC pointed out that none of these programs require an MRP and recovery of the related costs is all but assured if the programs are prudently managed.²⁶⁴

d. Staff

Regarding utility innovation, Staff acknowledges that BGE and Pepco proposed projects in their respective MRP filings that the companies believed were innovative and a few received Commission approval (*e.g.*, the underground system fault detector program proposed by both BGE and Pepco). However, Staff stated that it cannot verify whether more utility innovations have been achieved through MRPs relative to standard ratemaking.²⁶⁵ Staff believes that MRPs could provide an opportunity for innovation if utilities adequately demonstrate the quantitative benefits associated with proposed investments, but there is no evidence to show that forecasted distribution rates have tangibly contributed to more utility innovation.²⁶⁶ Staff notes that utilities may feel more comfortable proposing innovative ideas in an MRP because, if it is rejected, the utilities would not have already spent the funds such as would occur in a historical test year during a standard base rate case.²⁶⁷

Moreover, Staff concludes that the anticipated equitable distribution of risk has not materialized. Staff believes the current process places additional prudency risk on non-

²⁶⁴ *Id.* at 31.

²⁶⁵ Staff Initial Comments at 13.

²⁶⁶ *Id.*

²⁶⁷ *Id.*

utility parties and ratepayers while utilities are generally positioned to reconcile forecasted spending against actual spending. Staff explained that the “non-utility parties take on the added risk of defending or ostensibly supporting utility spending decisions they do not explicitly oppose, even if the utility itself does not defend its spending decisions.”²⁶⁸

e. AOBA

AOBA expressly rejected the notion that local distribution utilities should be innovators. Instead, AOBA stated that the utilities should focus on implementing proven, cost-effective technologies that support safe, reliable and resilient service, rather than pursuing speculative technologies whose customer benefits are uncertain.²⁶⁹

Regarding the question of risk distribution, AOBA points out that concerns were raised about the shifting of risks between utility shareholders and ratepayers in Pepco’s Case No. 9702 and the utilities’ responses seemed to lack sensitivity to the risk trade-offs when involved in the MRP ratemaking versus traditional HTY rate case. AOBA notes that under traditional ratemaking, the utility must make expenditure decisions with the understanding that such expenditures must be justified in a future rate proceeding.²⁷⁰ AOBA argues that although Order No. 89868 indicates that the utility bears the same burden under the MRP construct, in practice, the processes that have been applied seem to have “shifted significant risk from utility management and investors to ratepayers who have no control over the outcomes of investment decisions.”²⁷¹

²⁶⁸ *Id.*

²⁶⁹ AOBA Initial Comments at 14.

²⁷⁰ *Id.*

²⁷¹ *Id.*

f. MEA

MEA argues that MRPs may unfairly shift risks to ratepayers.²⁷² MEA notes that under the MRP structure, utilities can seek recovery of overspending through adjustment riders and reconciliation proceedings. MEA views this as a lower procedural hurdle than the traditional HTY rate case process that ordinarily would be required to address a revenue deficiency.

Although BGE argues that reconciliation protects customers because they ultimately pay actual costs rather than forecasts, MEA observes that utilities thus far on average have not underspent. Moreover, MEA argues that cost overruns can produce unexpected rate increases during the three-year MRP cycle, defeating the original goal of predictable rate increases.²⁷³

g. Constellation

Constellation commented that “[t]he implementation of BGE’s MRP has not significantly advanced the goals of fostering utility innovation or achieving a more equitable distribution of financial risks for customers relative to traditional ratemaking.”²⁷⁴ Constellation argued that BGE’s MRP has not addressed obstacles to investing in new technologies and has perpetuated existing barriers to innovation which means a bloated budget continues to be passed on to customers.²⁷⁵ Constellation suggests that innovation should include consideration of third party alternatives that could reduce customer costs rather than simply expanding utility-owned capital investment. Constellation further notes

²⁷² MEA Initial Comments at 3.

²⁷³ *Id.*

²⁷⁴ Constellation Initial Comments at 4.

²⁷⁵ *Id.*

that customers desire more control of their energy consumption and production, and BGE should be investing in these types of programs.²⁷⁶

Constellation concludes that MRPs have failed to achieve an appropriate balance between utility and customer financial risk.²⁷⁷ It recognizes that mechanisms such as deadbands and earnings share theoretically can allocate risk more fairly but stressed that as currently structured BGE's MRP relies heavily on strong regulatory oversight to prevent overstating expenditures during the rate case.²⁷⁸

Commission Decision

Concerning Shortened Cost Recovery: From the utility's perspective, the time between when a utility makes financial capital investments to the time the Commission approves new rates to reflect those investments—was certainly shortened, since the MRP process allows utilities cost recovery on forecasted capital expenditures. Given the size of BGE's and Pepco's MRP reconciliation filings, however, arguments could be made that even regulatory lag was not fully mitigated, but the utility was likely better off financially than they would have been under traditional HTY ratemaking.²⁷⁹ That said, it is unclear how this shortened time period meaningfully benefited ratepayers.

The Commission agrees with OPC, AOBA and Staff that the goal of a shortened cost recovery period was never intended to *only* benefit utilities, which appears to be the result. Rather, in exchange for the reduced regulatory lag, a myriad of benefits were

²⁷⁶ *Id.*

²⁷⁷ *Id.* at 5.

²⁷⁸ *Id.*

²⁷⁹ As noted at the hearing by BGE witness Case, the MRP was a credit-supportive mechanism when adopted in 2020. *See* Hr'g. Tr., Case Nos. 9618 and 9645 Vol. 1, 24:13–16 (Oct. 15, 2024).

expected to accrue to ratepayers. As further explained below, utilities were expected to provide sufficiently detailed information showing the customer benefits of proposed expenditures for the Commission and stakeholders, which did not occur, as well as to make a management commitment to complete the proposed projects and achieve the customer benefits and to do so within the approved revenue requirement, which also did not occur.

While reduced regulatory lag is a financial benefit to the utility, it is unclear if or how that translated into a financial benefit to ratepayers as there was no indication of improved debt ratings, measurably lower financing costs, or that it was in the ratepayers' interest to see their rates increase earlier than would have occurred under traditional ratemaking. While it is true the Commission marginally reduced ROE in response to approving an MRP, to the extent further forecasted test years are approved in future rate cases, the Commission finds that a quantitative examination should be undertaken to determine how ROE should be examined to reflect a reduction in regulatory lag. Additionally, although recent legislation has significantly modified the reconciliation process, the Commission has concerns regarding how much this process favored shareholders versus ratepayers.

Concerning Transparency: The Commission had expected that the MRP construct would have facilitated greater visibility into the utility capital investment and O&M plans relative to the traditional HTY ratemaking. While parties may have had greater insight into some utility planning and proposals of future spend than would be present in a traditional rate case, the lack of transparency and subsequent modifications to such plans diminished the value of such insight.

A consistent frustration expressed by all stakeholders participating in each of the MRP rate cases during this pilot period – and shared by the Commission – was that the utilities should have been more forthright with providing information upfront in their initial filing.

BGE interprets the increased volume in data requests it has fulfilled during the MRP rate cases compared to data requests fulfilled in a traditional rate case as evidence of greater stakeholder access, scrutiny and engagement with the utility investment decisions. The Commission views this as a failing of the initial filings in that such a sheer number of requests were required. Stakeholders found that this was especially challenging during the reconciliation proceedings when the utility had changed its spending plans on a project that was initially budgeted but failed to provide sufficient project details in its request for reconciliation to show the status of the originally budgeted project, why the change was made, and the related customer benefits supporting the change. The Commission finds that, from their initial filing, utilities should have taken a proactive upfront approach to sharing detailed information with parties, similar to how a person applies for a grant. In a grant application situation, the person seeking the grant tries to provide as much responsive and detailed information (nearly oversharing) as possible so that the application can be viewed in the most favorable light and prevail on the strength of the initial information provided, especially if there is no additional opportunity for supplementation. The Commission finds that utilities should take this same posture and proactively share the needed detailed information that they alone possess, which would aid stakeholders and the Commission in evaluating the benefits and costs of proposed projects and programs.

Additionally, the Commission notes that, while the Commission expected the utilities to have flexibility and management discretion as to the projects completed under the approved budgets, there appears to have been significant variations in what projects were added or removed such that the benefit of a preliminary review afforded by an MRP is lessened.²⁸⁰ At the end of the two-day legislative hearing, Chair Barve cautioned that the MRP process requires increasingly more detailed project forecasts, benefit analyses, stakeholder reviews, spending controls, and explanations for project substitutions, thereby necessitating an increased level of review. This may be at odds with the goal of reducing regulatory burden and therefore it is critical that an appropriate balance is achieved if MRPs or a different AFOR method is permitted in the future.

Concerning State Policy Goals: Order No. 89226 contemplated that the MRP may be helpful, if carefully implemented, in facilitating the achievement of the State's ambitious goals regarding electrification, renewable development, pipeline replacement, new customer solutions, grid resiliency and other State goals.²⁸¹ In comparison to traditional HTY ratemaking, the Commission has not observed that the MRP construct has advanced any of Maryland's key energy State policy goals. The Commission acknowledges that several of the utilities' MRP rate case filings have cited State goals as part of their rationale for proposing certain programs and projects. However, stakeholders have argued, and the Commission agrees, that typically the creation of new policy programs is better suited for review under a separate docket. Additionally, numerous policy

²⁸⁰ AOBA Initial Brief at 4-5.

²⁸¹ Order No. 89226 at 53.

proposals were made within the scope of the proposed PIMs in Case No. 9692, which the Commission rejected.²⁸²

The Commission notes that there are full dockets dedicated to issues such as reliability where future spend is discussed. The Commission acknowledges that the MRP likely allowed for a more detailed examination of specific projects that were driving toward policy goals than may have happened in strictly policy dockets. Nonetheless, the Commission cannot find that the MRP was the driver of new policies or that it served as any better of a venue for implementing large policy ideas than a dedicated proceeding would.

Concerning Administrative Burden: While utilities have argued that the MRP construct allows them the opportunity to file one rate case proceeding every three years as opposed to potentially filing up to three in the same three-year period, the Commission has found that the MRP as currently implemented did not result in a less administratively burdensome process. Further, the choice of how many rate case proceedings a utility files is a management decision and is not justification for maintaining the MRP construct. As structured, the Commission finds that the MRP construct, as implemented, had the effect of increasing the level of complexity involved in a rate case proceeding by introducing new filing requirements, requiring more detailed information covering a longer period and an evaluation of both forecasted and actual data versus only actual historic data under a traditional rate case model, the introduction of new annual filings new reporting requirements, and a reconciliation process. The Commission finds that, as implemented, the MRP construct was more resource- and time-intensive than the traditional HTY rate

²⁸² Order No. 90948 at 185-211.

case proceeding. The Commission believes that this problem could have been mitigated if the utilities had filed information more extensively upfront, at the beginning of the case. The discovery-intensive method of parties obtaining information from utilities in traditional HTY rate cases was meant to be largely replaced in MRPs by utilities providing more information upfront. Any future MRP framework will need to address this issue by ensuring that parties are provided with an abundance of information upon the filing of an MRP and that they are not left a step behind trying to obtain the needed information through discovery alone.

Concerning Predictable Rates: In Order No. 89226, the Commission stated that MRPs could provide “more predictable revenues for utilities and more predictable rates for customers” Unfortunately, while the Commission finds that as implemented, the MRP construct certainly allows the utilities a more predictable and steady revenue stream once rates are set based on the Commission-authorized revenue requirement, such was not the case for ratepayers. The wide gap between the forecasted expenditures and actual costs a utility sought to recover during the reconciliation periods made customer rates anything but predictable. While it may be true that MRPs can provide customers advance notice of the distribution rates that are listed in a utility’s tariff, this had nominal value when the MRP construct did not accurately capture the other increases that occurred during or as a result of the reconciliation process. As pointed out by Staff and other stakeholders, a customer’s total bill is affected by the commodity costs, transmission, taxes, the BSA, and other assessments outside of the MRP. Therefore, the Commission finds that the MRP construct did not make the customer rates any more predictable or stable, compared to the traditional HTY ratemaking.

Concerning Utility Innovation and Equitable Risk Distribution: The Commission finds that no more utility innovation was achieved under the MRP construct than would have occurred with the traditional HTY rate case. The Commission agrees with Staff's assessment that the MRP, as structured with the reconciliation process, had the effect of shifting the prudence-burden away from the utility by expecting other stakeholders to show imprudence instead of utilities affirmatively demonstrating that expenditures are prudent. The utility must retain the affirmative burden of demonstrating that the expenditures for which it seeks recovery are just and reasonable and are prudently incurred and managed.

In sum, the Commission finds that the intended MRP goals as set forth in Order Nos. 89226 and 89482 and described above were largely unachieved. Increased transparency and visibility into utility capital planning could have presented benefits for stakeholders but were largely absent from the proceedings. The Commission finds that the advance sharing of utility capital plans and investments need to be a central component of any forward-looking MRP construct in the future. On balance, the goal of shortening the cost recovery period for the utility was achieved however in the unanimous view of the stakeholders the inadequacy of transparency and the increased administrative burden to properly evaluate utility costs and projections leaves the current MRP construct an unfair situation.

B. Future of MRP Assessment—Maintain, Abandon, Reform

The threshold issue of this Lessons Learned proceeding is whether the current MRP framework should be maintained as currently structured, undergo major reforms, or be

abandoned altogether. This section outlines the main arguments offered by various parties supporting these outcomes.

BGE, Pepco and DPL favored retaining the current MRP framework as largely designed with modifications. OPC and AOBA primarily supported terminating the MRP framework and returning to the traditional HTY ratemaking model. Staff occupied a middle position, identifying serious deficiencies but ultimately supporting continued consideration of MRPs with significant reforms. MEA's position evolved throughout the Lessons Learned proceeding, going from cautious but not categorically opposed, to recommending suspension until adequate protections were established, to being more receptive once the NGEA eliminated the reconciliation component.

1. Maintain MRP Framework as designed with modification

- a. *BGE*

BGE urges the Commission to maintain MRPs as Maryland's principal alternative ratemaking framework but substantially modify the existing pilot structure. The Company argues that MRPs are well-suited to addressing emerging issues as they are a mechanism that considers the future, while retaining and even enhancing the ability to review history.²⁸³ It notes that “[i]f Maryland was to move away from MRPs, *it would be swimming upstream alone as the only state or jurisdiction in the nation to be doing so* at this critical juncture in the nation’s energy journey.”²⁸⁴ BGE, citing its Exelon’s Chief Executive Officer Calvin Butler, notes that “[y]ou cannot build a grid of the future playing

²⁸³ BGE Initial Brief at 3.

²⁸⁴ *Id.* at 3-4 (emphasis in original).

with the same old playbook.”²⁸⁵ BGE states that the focus must now become “what mechanism can best achieve this goal for Maryland and its citizens *in the most cost-efficient and cost-effective way*.”²⁸⁶ BGE argues that “[n]ot only are MRPs the right mechanism for utilities, stakeholders and customers, they are also the right utility ratemaking mechanism to support the economic growth the State and Governor Moore are looking to deliver.”²⁸⁷ BGE states that its first proposed MRP (Case No. 9645) was projected to generate approximately \$5.1 billion during the MRP rate years of 2021 through 2023.²⁸⁸

Regarding capital spending, BGE argues that State policies, and not MRPs, are driving capital investment. Specifically, BGE states that capital expenditures are rising due to the need to replace aging infrastructure and factors such as “customer demand and environmental, social and governance considerations, amid a broader trend toward utility sector decarbonization.”²⁸⁹ BGE emphasizes that its Commission-approved electric and gas distribution capital spending is projected to grow only 0.3% from 2023–2026, compared with national utility capital expenditure growth exceeding 6%.²⁹⁰ BGE argues that the MRP construct is giving the Commission an ability to preview capital expenditures, which is resulting in a more measured level of approved BGE investments for the 2024–2026 MYP period.²⁹¹ BGE indicates that it realizes its capital investment decisions ultimately will end up on customer bills in the form of electric distribution rates. Looking at the trend of BGE’s average residential electric delivery rates before MRPs and over the

²⁸⁵ BGE Initial Brief at 4.

²⁸⁶ *Id.* (emphasis in original).

²⁸⁷ BGE Initial Brief at 5.

²⁸⁸ *Id.*

²⁸⁹ *Id.* at 7.

²⁹⁰ *Id.* at 9.

²⁹¹ *Id.* at 8.

period that MRP pilots have been in place, BGE states that its residential electric distribution rates remain in the first quartile nationally – lower than more than 75% of the utilities in its comparison group.²⁹²

Next, BGE stated that while parties in this docket present differing views, there is one area of agreement – cost control is an area where the MRP structure could be strengthened.²⁹³ The Company included an Attachment 1 to its brief that contains some recommended improvements. Most significantly, BGE recommends that the Commission replace the annual reconciliation process with an earnings/risk sharing mechanism (“ERSM”).²⁹⁴ BGE contends that the ERSM would strengthen cost control incentives in the MRP, address concerns regarding asymmetry of information, reduce administrative burden, improve rate predictability, better balance the distribution risks between the utility and ratepayers, and even improve transparency.²⁹⁵

BGE notes that earnings-sharing mechanisms are not novel: according to its analysis, MRPs, ERSMs, or both are used in approximately two-thirds of U.S. jurisdictions.²⁹⁶ BGE states that the Commission could build upon the previous Case No. 9618 Working Group recommendations that began looking at this approach and that were included in the December 20, 2019 Working Group Implementation Report.²⁹⁷

BGE argues that under the ERSM proposal, most differences between forecast and actual spending would no longer receive full reconciliation treatment. Instead, utilities and

²⁹² *Id.* at 9.

²⁹³ *Id.* at 5.

²⁹⁴ *Id.* at 6.

²⁹⁵ *Id.*

²⁹⁶ *Id.* at 11.

²⁹⁷ *Id.* at 12, *citing* Case No. 9618, Working Group Implementation Report (Maillog No. 227958).

customers would share the financial consequences of performance. BGE contends that the mechanism would encourage the utility to achieve efficiency because it could retain part of the savings. Conversely, if actual costs exceeded forecasts, the utility would bear part of that downside rather than automatically seeking full recovery from customers. BGE argues that replacing the reconciliation process with the ERSM would place considerably more risk on the utility because costs such as inflation, supply-chain pressures and other unexpected cost increases could no longer simply be fully reconciled.²⁹⁸ BGE notes that the ERSM proposal directly responds to the concern that the existing reconciliation mechanism shifts too much of the forecast risk on customers.

BGE's ERSM proposal would consist of:

- (i) establishing a symmetric basis point deadband that is 25-basis-point deadband above and below the authorized ROR;
- (ii) utilities operating under an MRP would still make Annual Informational Filings ("AIF") within 90 days of the end of the rate year and would continue to report actual earned returns;
- (iii) if a utility's actual earned ROR falls within the deadband, there would be no adjustment;
- (iv) if a utility's actual earned ROR exceeds the upper boundary, 50% of the excess earnings would be returned to customers. BGE proposes that this can take place any time using the MRP Adjustment Rider after the AIF to ensure customers receive their credit in a timely manner;
- (v) if earnings fall below the lower boundary, the utility could recover 50% of the shortfall necessary to reach the lower boundary. BGE proposes that the utility's AIF would include the calculations and support necessary to demonstrate the amount sought by the utility, which could be recovered through the MRP Adjustment Rider (if approved or be addressed in the Company's next base rate case), and

²⁹⁸ *Id.* at 13.

- (vi) any exogenous storm costs variances deferred in a regulatory asset/liability could be built into base rates at the time of the next base rate case, including any carrying costs.²⁹⁹

BGE argues that the ERSM enhances MRPs in the following ways: (1) by replacing the full reconciliation process in the current MRP structure; (2) by increasing rate predictability; and (3) increasing cost reduction incentives which will act as a control that limits the amount able to be reconciled, while ensuring customers benefit from savings and utilities would be partially protected from increased costs. BGE also notes that under this proposal all costs would remain subject to prudence review.³⁰⁰

BGE indicated that due to the concerns raised by the Commission and other parties during the two-day hearing about exogenous costs in the ERSM, the Company is no longer proposing to adjust these costs out of the ERSM calculation.³⁰¹ BGE stated that it would commit to proposing a more appropriate ratemaking treatment of storm costs in its next base rate case if the Commission accepts the ERSM proposal and gives direction for it to go into effect in future MRP applications.³⁰² BGE maintained that implementation of the ERSM would address many of the deficiencies in the current MRP structure while maintaining transparency into the utility's workplan and spending, which is critical to align utility work plans and spending plans with state policy while ensuring affordability.³⁰³

In addition to BGE's ERSM proposal, the Company recommended several other MRP enhancements that were included as Attachment 1 of its December 13, 2024 brief. BGE noted that the Joint Exelon Utilities met with Staff regarding recommendations to

²⁹⁹ *Id.* at 14-15.

³⁰⁰ *Id.* at 16.

³⁰¹ *Id.* at 17.

³⁰² *Id.* at 17-18.

³⁰³ *Id.* at 19.

improve MRPs and sought and incorporated feedback provided.³⁰⁴ BGE stated that it does not view the list of enhancements in its Attachment 1 as comprehensive “but rather a continued implementation of learnings from a journey that all parties have undertaken in Maryland.”³⁰⁵

Regarding prudence review, BGE reiterates that the prudence standard and process are the same no matter what ratemaking model is used by a utility.³⁰⁶ BGE maintains that the relevant question remains whether the utility acted reasonably based upon the information available when the decision was made, rather than judging the decision after the fact.³⁰⁷

BGE also argues that MRPs are superior to both one-year forecasted test years (“FTYs”) and the traditional HTY rate case. BGE points out that one-year FTYs would preserve forecasting problems while requiring more frequent rate cases, increasing administrative burdens and reducing rate predictability. In contrast, the traditional HTY rate case would return Maryland to backward-looking ratemaking and rely heavily on regulatory lag as a cost-control mechanism. BGE claimed, “Both alternatives leave utilities and all parties in a position where rate case filings from multiple utilities in Maryland will all be pancaked at the same time.”³⁰⁸

BGE argues that there is a time and place for both MYPs and other policy specific proceedings.³⁰⁹ BGE contends that proceedings involving performance incentive metrics

³⁰⁴ *Id.*

³⁰⁵ *Id.* at 20.

³⁰⁶ *Id.*

³⁰⁷ *Id.* at 21.

³⁰⁸ *Id.* at 25.

³⁰⁹ *Id.* at 30.

and distribution system planning (“DSP”) can complement an MRP but cannot substitute for it.³¹⁰ For example, BGE states that only one of its 24 electric and gas capital work categories is covered by the DSP proceeding.³¹¹ The DSP can provide detailed examination of particular distribution-planning questions, while the MYP allows those investments to be evaluated within the utility's overall work plan.³¹²

BGE devotes attention to the financial consequences of abandoning MRPs and argues that ratings increase a utility's borrowing costs and those costs ultimately flow into customer rates.³¹³ BGE points to Maryland's changing regulatory rankings and argues that uncertainty about MRPs could contribute to a less favorable investment environment.³¹⁴ It also notes that BGE had been placed on negative credit watch and uses recent utility downgrades elsewhere as an example of how regulatory decisions can increase financing costs. BGE therefore argues that returning to traditional ratemaking could both slow needed infrastructure investment and raise customers' long-term financing costs.³¹⁵

Finally, in its brief, BGE requests the Commission make three principal decisions:

- (i) continue MRP ratemaking but eliminate the existing full reconciliation, replacing it with an ERSM for future MRPs and authorizing regulatory asset/liability treatment for minor-storm cost variances;³¹⁶
- (ii) address new legislative or regulatory mandates separately during an MRP period through the proceeding implementing the new mandate, because those costs would not have been incorporated into existing MRP rates and full reconciliation would no longer exist; and

³¹⁰ *Id.* at 30-31.

³¹¹ *Id.* at 31-32.

³¹² *Id.* at 32.

³¹³ *Id.*

³¹⁴ *Id.* at 33.

³¹⁵ *Id.* at 34.

³¹⁶ *Id.* at 37.

- (iii) adopt the additional MRP improvements provided in Attachment 1 to BGE's brief, particularly those designed to improve transparency and reduce information asymmetry.³¹⁷

Concerning the impact of the NGEA, in its updated brief submitted on September 5, 2025, BGE argues that its prior proposal is in alignment with the new restrictions adopted by the Maryland General Assembly prohibiting future MRPs from using reconciliations and requiring a demonstration of customer benefits.³¹⁸ BGE argues that the legislation validates its proposed direction of retaining forward-looking MRPs by eliminating reconciliation with a different cost-control mechanism.

b. The PHI Companies

The PHI Companies argue that Maryland should retain MRPs rather than return to traditional HTY ratemaking, but they acknowledge other stakeholder concerns and recommend substantial changes to improve efficiency, transparency, accountability, and cost control.³¹⁹ The PHI Companies central position is that MRPs have achieved the Commission's intended objectives: fewer rate cases, more predictable customer rates, greater advance transparency into utility investments, improved ability to implement State climate and electrification policies, and a better opportunity for utilities to earn their authorized returns.³²⁰ The PHI Companies propose replacing the existing reconciliation process with the ERSM proposed by BGE and strengthening project reporting.³²¹ Additionally, the PHI Companies propose the following procedural improvements:

³¹⁷ *Id.*

³¹⁸ Joint Exelon Utilities Updated Brief at 2.

³¹⁹ The PHI Companies Initial Brief at 5.

³²⁰ *Id.* at 1.

³²¹ *Id.* at 5-9.

- (i) stakeholder meetings at important stages of the MRP to discuss budgeting, projects, and changes with utility subject-matter experts;
- (ii) enhanced annual project-list filings, including additional support for new projects exceeding \$1 million;
- (iii) more documentation explaining differences between budgeted and actual spending; and
- (iv) greater attention to identifying and explaining the customer benefits associated with proposed projects.³²²

The PHI Companies noted that they, along with BGE, met with Staff and offered to meet with OPC, in order to share and obtain feedback on the recommended MRP enhancements included as Attachment 1 to its Initial Brief.³²³ The PHI Companies argue that the MRPs continue to demonstrate the following benefits:

Administrative efficiency. Before MRPs, the PHI Companies note they generally filed rate cases every 12–18 months. MRPs reduced the number of full rate case proceedings. The PHI Companies acknowledge, however, that individual MRP cases can themselves be resource intensive.³²⁴

Rate predictability and affordability. The PHI Companies highlight that because the Commission approved three-year revenue requirements in Case Nos. 9655 and 9681, customers knew the approved rates for each year of an MRP rather than facing uncertainty about when the next traditional rate case will occur.³²⁵ In contrast, the PHI Companies contend that under traditional HTY ratemaking, customers will not know the timing nor

³²² *Id.* at 9.

³²³ *Id.* at 11.

³²⁴ *Id.* at 11-13.

³²⁵ *Id.* at 13.

amount of the utility's next rate case increase.³²⁶ The PHI Companies argue that MRPs also allow increases to be spread over time rather than imposed as a single larger adjustment.³²⁷

Flexibility. The PHI Companies assert that MRPs allow utilities to adjust capital programs to reflect changes in the business environment, rather than changes in the utility's actual revenue and costs.³²⁸ The PHI Companies cite storms, inflation, equipment failures, supply-chain problems, permitting delays, and transformer shortages as examples of business environment changes. Despite such changes, the PHI Companies pointed out that spending during Pepco's first MYP remained within 5% of budget.³²⁹

Transparency. The PHI Companies emphasize that MRPs enable the Commission and stakeholders an opportunity to examine proposed capital projects before the money is spent, unlike traditional HTY ratemaking, which primarily examines historical expenditures.³³⁰ The PHI Companies note that the MRP construct requires utilities to provide project-level work plans and justifications, and those investments can subsequently be examined again for prudence.

Customer refunds and savings. The PHI Companies point out the MRP construct also allows the utilities to pass on financial benefits to customers and cite that in 2024, DPL returned \$7.3 million in overcollections to customers.³³¹ The Companies also argue that improved utility financial health can reduce borrowing costs and that MRPs facilitate mechanisms such as accelerated tax-benefit credits.³³²

³²⁶ *Id.*

³²⁷ *Id.* at 15.

³²⁸ *Id.*

³²⁹ *Id.* at 17.

³³⁰ *Id.* at 18.

³³¹ *Id.* at 26.

³³² *Id.*

Authorized return and financial health. The PHI Companies report that Pepco’s earned ROE averaged 7.89% during the seven years before its first MRP versus an average of 8.74% during the three MRP rate years.³³³ Additionally, the PHI Companies note that DPL reported an average earned ROE of 6.59% from 2011–2021 versus an average 10.73% in Rate Year 1 of its first MYP.³³⁴ The Companies argue that a financially healthy utility can obtain capital more favorably, ultimately benefiting customers.³³⁵

State policy objectives. The PHI Companies maintain that forward-looking MRPs better position utilities to carry out state policy such as electrification, renewable energy, grid resiliency, EV infrastructure, distributed energy resources, and Maryland's climate policies.³³⁶ In fact, the PHI Companies report that “12-20% of the Pepco spending portfolio is in support of state goals and 11% of the Delmarva Power spending portfolio is in support of state goals.”³³⁷

In their initial brief, the PHI Companies also responded to other stakeholders’ proposals discussed during the MRP Lessons Learned hearings on October 15-16, 2024. The brief considers several alternatives raised during the Commission's hearings.

One-year MRP. Several Commissioners inquired about whether a one-year MRP should be instituted. The PHI Companies comment that this alternative is problematic. First, due to the shorter duration, the utilities would return to filing rate cases more frequently similar to prior to the MRP Pilot period.³³⁸ Second, they argue that longer MRPs

³³³ *Id.* at 23.

³³⁴ *Id.*

³³⁵ *Id.* at 21.

³³⁶ *Id.* at 25.

³³⁷ *Id.*

³³⁸ *Id.* at 27.

create more stability where utilities and contractors can plan work and support economic development in Maryland.³³⁹ The PHI Companies noted that Pepco previously estimated that its multi-year investment proposal would support approximately 1,150 direct jobs annually, 275 indirect jobs annually, and about \$1 billion in Maryland economic activity.³⁴⁰ The PHI Companies contend that a one-year MRP would retain the deficiencies of traditional HTY ratemaking while failing to provide the support for longer term economic development associated with an MRP.³⁴¹

Distribution System Planning (DSP).³⁴² At the hearing, stakeholders suggested that the DSP process can provide transparency into a utility's capital plan and the MRP would not be needed. The PHI Companies argue that the DSP process is not a substitute because MRPs give stakeholders a more comprehensive picture of capital, costs, revenues, and other utility plans in a single proceeding, whereas DSP provides information primarily about distribution capital planning.³⁴³

Bill Stabilization Adjustment (BSA).³⁴⁴ During the Lessons Learned hearing, OPC suggested that the BSA was duplicative of the MRP.³⁴⁵ The PHI Companies argue that a BSA serves a different function from the MRP. The BSA stabilizes revenues associated with variations in sales but does not permit revenues to reflect forecasted changes in the utility's cost of service.³⁴⁶

³³⁹ *Id.*

³⁴⁰ *Id.*

³⁴¹ *Id.* at 27-28.

³⁴² *Id.* at 29.

³⁴³ *Id.*

³⁴⁴ *Id.* at 30.

³⁴⁵ *Id.*

³⁴⁶ *Id.*

Regarding the NGEA, The PHI Companies filed jointly with BGE an updated brief submitted on September 5, 2025 and support the comments summarized above under BGE finding that the new statutory provisions align with BGE's and the PHI Companies' ERSM proposal yet maintaining the forward looking MRP construct.³⁴⁷

c. WeaveGrid

WeaveGrid supports continuing MRPs beyond the pilot.³⁴⁸ Its argument is less about conventional ratemaking principles and more about the need for forward-looking grid planning to achieve Maryland's electrification and clean-energy policies.³⁴⁹ WeaveGrid offered the following support.

Forward-looking planning. WeaveGrid believes utilities and regulators need a multi-year planning framework to achieve the State of Maryland's ambitious climate goals.³⁵⁰

Stakeholder participation. WeaveGrid argues that MRPs provide an opportunity for a diverse set of stakeholders to participate before utilities make major investments.³⁵¹ WeaveGrid regards this prospective participation as a major advantage.

EV integration. WeaveGrid argues that long-term planning can facilitate cost-effective integration of EV charging. WeaveGrid comments that stable and predictable rate structures are particularly important for EV time-of-use programs designed to shift charging to beneficial periods.³⁵²

³⁴⁷ Joint Exelon Utilities Updated Brief at 2.

³⁴⁸ WeaveGrid Initial Comments at 1.

³⁴⁹ *Id.*

³⁵⁰ *Id.*

³⁵¹ *Id.*

³⁵² *Id.* at 2.

Distributed energy resources. WeaveGrid claims that increasing EVs, distributed generation, and residential smart devices make distribution-system planning increasingly complex.³⁵³ WeaveGrid views MRPs as a mechanism for anticipating these changes.

State clean-energy policy. WeaveGrid also asserts that MRPs can help coordinate utility investment with Maryland's climate, electrification, distributed-energy-resource, and innovation policies.³⁵⁴

d. IBEW

IBEW stated that as a general proposition it supports MRPs.³⁵⁵ IBEW believes MRPs have improved transparency into forecasted and actual utility O&M and capital expenditures.³⁵⁶ However, IBEW argued that reform was needed and specified three main recommendations concerning: affiliate costs, procedural participation, and performance incentives.

Affiliate transactions. IBEW wants every reconciliation filing to include a Schedule of Affiliate Transactions.³⁵⁷ IBEW argued that these reports would shed light on Maryland utilities' reliance on the resources of the other members of their parent companies and ensure that the utility is charging and being charged an appropriate amount for transactions between sister affiliates.³⁵⁸ This review can show whether transactions involving utilities and service companies within the same corporate family are genuinely arm's length. IBEW's specific concern is storm and labor costs, and making sure the

³⁵³ *Id.*

³⁵⁴ *Id.*

³⁵⁵ IBEW Initial Comments at 2.

³⁵⁶ *Id.*

³⁵⁷ *Id.*

³⁵⁸ *Id.*

Commission has enough information to determine whether these expenses are prudent and appropriately priced.³⁵⁹

Intervention rights. IBEW proposes reopening intervention for approximately one month after a utility files its annual reconciliation.³⁶⁰ IBEW’s rationale is that parties cannot know at the beginning of a multi-year proceeding what issues may arise years later.

Performance Incentive Mechanisms. IBEW recommends eliminating PIMs from the MRP.³⁶¹ IBEW argues that the authorized ROE already compensates investors and provides the utility an opportunity to earn a reasonable return; utilities should not necessarily receive additional rewards for satisfying obligations inherent in providing utility service.

e. Prime Partners Engineering

During the October 15, 2024 hearing, Mr. Adrian Davis testified on behalf of the Prime Partners Engineering (“Prime Partners”) to express support for the MRP. Mr. Davis testified that the MRP process “allowed BGE to make investments in their distribution systems to support increased electrification anticipated by state and county legislation, which benefits customers through a more reliable and resilient grid.”³⁶² Mr. Davis asserted that this was essential for supporting economic development in Baltimore and Maryland. As a minority contractor for Pepco providing project management and engineering services, Mr. Davis testified that Prime Partners has done work on Pepco’s and BGE’s

³⁵⁹ *Id.*

³⁶⁰ *Id.* at 3.

³⁶¹ *Id.*

³⁶² Hr’g. Tr., Case Nos. 9618 and 9645, Vol. 1, 14: 6–10 (Oct. 15, 2024).

electrical distribution feeders throughout their service territories.³⁶³ Additionally, Mr. Davis commented that Prime Partners is focused on the approval of BGE’s MRP because it enables the firm to work on longer term projects beyond one year which supports its mission of creating a more sustainable environment for its communities. Additionally, Mr. Davis asserted that MRPs afford businesses and residents the benefit of reliable and predictable rates.³⁶⁴

f. Stella May Contracting

During the October 15, 2026 hearing, Mr. Christian Johanson testified on behalf of Stella May Contracting, a minority business enterprise utility contractor, and expressed strong support for the MRP process. Mr. Johanson testified that since its launch, the MRP framework has become essential for creating predictable rates for customers, as well as providing a stable revenue model for electric and gas utilities, benefitting both consumers and service providers.³⁶⁵ He also asserted that MRPs are “critical for MBE utility contractors as it enables us to plan for future work.”³⁶⁶

g. Edison Electric Institute

During the October 15, 2026 hearing, Ms. Stephanie Johnson testified on behalf of the Edison Electric Institute (“EEI”) to express support for the MRP. Ms. Johnson highlighted that “twenty-nine states across the country have introduced various rate frameworks that include forward-looking test years that bring tangible benefits to

³⁶³ *Id.* at 14:22–15:1.

³⁶⁴ *Id.* at 15:2–10.

³⁶⁵ *Id.* at 16:11–15.

³⁶⁶ *Id.* at 16:18–19.

customers and communities alike.”³⁶⁷ She further noted that several electric companies have introduced PIMs in conjunction with forward-looking ratemaking or MRPs. She asserted that “[t]hese mechanisms have led to gains in reliability, improved performance and operational savings that are shared with customers.”³⁶⁸ Ms. Johnson testified that MRPs afford residents and businesses the benefit of reliable and predictable rates and commented that EEI has observed states across the country enjoy success with MRPs to meet priorities across stakeholders.³⁶⁹ Last, Ms. Johnson urged the Commission “to continue allowing electric companies the flexibility to participate in MRPs.”

h. Maryland Chamber of Commerce

During the October 15, 2024 hearing, Mr. Grayson Wiggins testified on behalf of the Maryland Chamber of Commerce (“MCC”) to express support for the MRP. Mr. Wiggins stated that the MCC believes that MRPs provide “transparency, stability and reliability.” Regarding transparency, Mr. Wiggins testified that the MRP process promotes transparency “because it allows utilities to inform the public and regulators of planned system improvements ahead of time.”³⁷⁰ He also stated that it provides stability because “it allows utilities to recover funds for the work they do as they start to serve customers rather than after the fact.”³⁷¹ He noted that the MCC believes more stable funding improves planning and allows for more innovation, which promotes reliability for the grid and the state energy use.

³⁶⁷ *Id.* at 18:2–5.

³⁶⁸ *Id.* at 18:9–11.

³⁶⁹ *Id.* at 18:12–14.

³⁷⁰ *Id.* at 13:2–5.

³⁷¹ *Id.* at 13:6–9.

2. Abandon MRP framework and return to traditional HTY ratemaking model

a. *OPC*

OPC argues that Maryland's MRP experiment has failed and should be terminated or sunset, rather than modified or converted into a permanent alternative ratemaking mechanism.³⁷² It noted that the Commission established the MRP pilot under its authority to adopt alternative forms of regulation and has the power to sunset MRPs under the same authority.³⁷³ OPC notes that none of the NGEA's MRP-related provisions limit the Commission authority to terminate the MRP Pilot and sunset the MRP construct upon a finding that MRPs are not consistent with the public good.³⁷⁴ In fact, OPC argues that the NGEA demonstrates the legislature's concern that the five years of MRP experience demonstrates that the MRPs are inherently flawed, increase customer rates, shift financial risks from utility shareholders to customers, weaken prudency review, and fail to produce demonstrable customer benefits.³⁷⁵ Further, OPC contends that the NGEA raises the threshold for approval because the legislature doubted whether MRPs could ever be consistent with customer interests.³⁷⁶

OPC's Updated Brief identifies several reasons why the Commission should terminate the MRP framework. *First*, OPC argues that the MRPs have been harmful rather than beneficial to customers.³⁷⁷ According to OPC's calculations, since implementation of MRPs, distribution rates increased for each utility by the following percentages: BGE

³⁷² OPC Updated Brief at 5.

³⁷³ *Id.*

³⁷⁴ *Id.*

³⁷⁵ *Id.* at 1.

³⁷⁶ *Id.* at 2.

³⁷⁷ *Id.* at 6.

electric by 30%, Pepco by 33% and DPL by 17%.³⁷⁸ OPC further asserts that the average annual percentage rate increases under MRPs have been at least 40% higher than under Maryland's standard ratemaking from 2006–2020.³⁷⁹ OPC attributes these increases partly to increased capital investment and operating expenses. For example, it states that BGE added more than \$2 billion in plant during its first MRP and Pepco added \$675 million, even after the Commission reduced their proposed budgets.³⁸⁰ OPC therefore characterizes MRPs as accelerating rather than moderating customer rate increases.³⁸¹

Second, OPC asserts that MRPs provide no real benefit to customers. OPC argues the utilities' claims that MRPs deliver transparency, advance State policy goals and reduce administrative burdens are not supported by the record.³⁸² As noted in Section III. A. above, OPC argues that “transparency has declined”³⁸³; the “MRPs have not advanced State policy objectives”³⁸⁴; and “administrative burdens have worsened.”³⁸⁵

Third, OPC contends that MRPs are unworkable and the enactment of the NGEA has not cured the MRP's construct's structural flaws that rewards utilities and shifts risks to customers.³⁸⁶ OPC argues that these structural flaws “cannot be mitigated through tweaks to particular features” and although the NGEA prohibits utility reconciliation filings, “the core anti-consumer features of the MRP construct remain [such as] limitations on the review of capital workplans, reliance on utility forecasts, and reduced regulatory lag

³⁷⁸ *Id.* at 7.

³⁷⁹ *Id.*

³⁸⁰ *Id.*

³⁸¹ *Id.* at 8.

³⁸² *Id.* at 9.

³⁸³ *Id.*

³⁸⁴ *Id.*

³⁸⁵ *Id.* at 10.

³⁸⁶ *Id.*

time."³⁸⁷ It is OPC's belief that these features undermine important consumer protection and fail to benefit the public interest.

Fourth, OPC argues that MRPs weaken prudency review, which is "the central cornerstone of consumer protection in monopoly regulation."³⁸⁸ A central OPC concern is that MRPs undermine traditional prudency review, which protects customers by ensuring that utilities recover only necessary, reasonable, and responsibly incurred costs.³⁸⁹ Under an MRP, OPC notes that large portfolios of future capital spending are approved prospectively. OPC argues this creates ambiguity about whether a subsequent prudency review becomes an after-the-fact assessment of execution alone and ignores whether the projects were justified at the outset.³⁹⁰ OPC points to differing statements by BGE witnesses during the October 2024 hearings as evidence that even the utilities lack a consistent explanation of how prudency review operates under MRPs.³⁹¹ OPC suggests that this uncertainty can effectively insulate previously approved investments from meaningful subsequent scrutiny.³⁹²

Regarding the NGEA, OPC contends that the new provisions of PUA § 4-213 create a higher standard of review than existed under PUA 7-505(c), which allowed alternative ratemaking if it was "in the interest of the public."³⁹³ OPC contends that "by amending PUA § 7-505 to make it 'subject to' § 4 -213, the legislature unmistakably signaled that customer benefits must be affirmatively shown—not presumed."³⁹⁴ To meet this test, OPC

³⁸⁷ *Id.*

³⁸⁸ *Id.* at 11.

³⁸⁹ *Id.*

³⁹⁰ *Id.*

³⁹¹ *Id.*

³⁹² *Id.*

³⁹³ *Id.* at 15.

³⁹⁴ *Id.*

argues that utilities would need to demonstrate tangible, measurable benefits such as improved reliability, safety and emissions reductions—directly tied to the MRP framework.³⁹⁵ OPC commented that “none of the MRP filings to date provide such evidence” but instead “have obscured accountability and worsened customer outcomes.”³⁹⁶

Additionally, OPC interprets PUA § 4-213 as prohibiting the *utility* from seeking reconciliation, but not preventing OPC, Staff, or the Commission itself from seeking a downward adjustment where the utility has over-recovered its revenue requirement.³⁹⁷ OPC acknowledges, however, that Exelon disputes this interpretation.³⁹⁸ OPC notes that this contention underscores the legal uncertainty about how MRPs as currently structured would function post-NGEA. OPC further argues that any future AFOR must resolve the questions clearly and unambiguously.³⁹⁹

OPC acknowledges that while overall protective of ratepayers, the elimination of reconciliations by the NGEA removes a central component of the Commission's original MRP construct.⁴⁰⁰ OPC notes that reconciliation was intended to address differences between forecasted and actual costs and provide an opportunity for prudence review. Without it, OPC argues that an MRP essentially becomes a future test-year mechanism based on forecasts without a reliable true-up process.⁴⁰¹ OPC argues that “MRPs without reconciliation heighten the already high risks to customers of utility over-forecasting” and concludes that the NGEA reconciliation provisions “removes the one mechanism that

³⁹⁵ *Id.* at 16.

³⁹⁶ *Id.*

³⁹⁷ *Id.* at 27 (emphasis in original).

³⁹⁸ *Id.* at 28.

³⁹⁹ *Id.*

⁴⁰⁰ *Id.* at 16-19.

⁴⁰¹ *Id.* at 17-18.

prevented MRPs from becoming entirely one-sided.”⁴⁰² Further, OPC states that “[b]y stripping out reconciliation and layering in the ‘customer benefit’ test, the legislature signaled that MRPs are not presumptively in the public interest.”⁴⁰³

Hence, OPC suggests that the NGEA makes sunseting the MRP pilot the only lawful and prudent course and to return to traditional HTY ratemaking.⁴⁰⁴ However, if the Commission finds it appropriate to continue with MRPs, then OPC firmly believes that “a wholesale reevaluation, through a stakeholder process, of whether any alternative form of regulation can ever satisfy”⁴⁰⁵ the NGEA is necessary.

OPC rejects BGE’s recommendation that its proposed ERSM might address the shortcomings of MRPs.⁴⁰⁶ OPC argues that the ERSM proposal would not address the systematic problems of the MRPs. First, OPC claims that the ERSM is legally prohibited because it is “reconciliation under another name,”⁴⁰⁷ which contradicts the NGEA. According to OPC, adjusting customer rates based on the difference between actual and authorized returns constitutes reconciliation of revenue variances prohibited by PUA § 4-213.⁴⁰⁸ Second, OPC argues that even if an ERSM were legally permissible, it would not satisfy the NGEA’s customer-benefit requirement.⁴⁰⁹ OPC notes that the Commission’s original rationale for reconciliation stated that “Utilities cannot reliably forecast future costs, and customers should not be forced to bear the consequences of forecast errors.”⁴¹⁰

⁴⁰² *Id.* at 18.

⁴⁰³ *Id.* at 19.

⁴⁰⁴ *Id.* at 20 and 25.

⁴⁰⁵ *Id.* at 20.

⁴⁰⁶ *Id.*

⁴⁰⁷ *Id.*

⁴⁰⁸ *Id.* at 22.

⁴⁰⁹ *Id.* at 23.

⁴¹⁰ *Id.* at 24.

OPC argues that BGE’s ERSM proposal “offers no credible substitute to address the inevitability of forecasting errors.”⁴¹¹

Again, OPC argues that if the Commission wishes to move forward with any future AFOR, it should not simply modify the existing MRP framework.⁴¹² Instead, OPC recommends that the Commission should start over through a robust stakeholder process that establishes:⁴¹³

- (i) clear definitions and metrics for customer benefits;
- (ii) safeguards against excessive capital spending;
- (iii) appropriate allocation of forecasting and financial risks;
- (iv) effective prudency review; and
- (v) a clear understanding of any adopted AFOR and existing statutory language. If such reevaluation is done, OPC points out that the BSA also must be reexamined⁴¹⁴ and contends that the BSA effectively operates as a built-in reconciliation. Since the BSA already reduces utility revenue risk, OPC questions why utilities also need MRPs or another AFOR layered on top of it.⁴¹⁵ OPC therefore recommends reevaluating the BSA as part of any comprehensive consideration of future alternative rate regulation.

Until a full reevaluation is completed, OPC recommends the Commission return to traditional HTY ratemaking. OPC argues that HTY ratemaking “remains the only construct that ties rates to *actual costs* and provides customers with a measure of protection against inflated forecasts.”⁴¹⁶ OPC notes that a central feature of HTY ratemaking is regulatory lag, which OPC argues acts as a critical safeguard for customers.⁴¹⁷ Under traditional

⁴¹¹ *Id.*

⁴¹² *Id.* at 25.

⁴¹³ *Id.* at 25-26.

⁴¹⁴ *Id.* at 30.

⁴¹⁵ *Id.*

⁴¹⁶ *Id.* at 26 (emphasis in original).

⁴¹⁷ *Id.* at 31.

ratemaking, a utility generally must manage cost increases until new rates are approved. OPC views this regulatory lag as a feature—not a defect—because it creates an incentive for utilities to control spending. OPC, therefore, recommends that the Commission “reaffirm that HTY ratemaking is not an outdated relic, but the strongest available tool to ensure just and reasonable rates”⁴¹⁸ and return to it as the default ratemaking approach in Maryland.

b. AOBA

AOBA, like OPC, recommends terminating MRP ratemaking and returning to traditional HTY ratemaking.⁴¹⁹ AOBA argues that based on its experience to date, MRPs have been devoid of the needed support for the forecasted budgets the Commission has relied upon to approve rates for future MRP rate years, utility actual expenditures have substantially exceeded the costs upon which MRP rate approvals were premised, and meaningful prudence reviews are essentially non-existent.⁴²⁰ In its Final Brief, AOBA expressed three main structural problems with MRPs: (1) Reconciliation is undermined by utilities' reclassification and reassignment of costs; (2) Utility forecasts and actual spending lack sufficient transparency; and (3) Meaningful after-the-fact prudence reviews have largely been absent, allowing substantial rate-base growth.⁴²¹ AOBA argues that “[t]he Commission’s past determinations of potential benefits do not reconcile with actual experience.”⁴²² Additionally, AOBA argues that because utilities possess essentially all of

⁴¹⁸ *Id.* at 33.

⁴¹⁹ AOBA Final Brief at 30.

⁴²⁰ *Id.* at 1-2.

⁴²¹ *Id.* at 2.

⁴²² *Id.* at 3.

the information concerning their spending decisions, they must be held responsible for demonstrating the prudence of the expenditures they incur.⁴²³ AOBA contends that utilities have attempted to shift the burden to other parties in MRP rate cases who lack direct access to internal records and communications.⁴²⁴

AOBA argues that the reconciliation process encourages spending above approved budgets.⁴²⁵ AOBA cites BGE's and Pepco's first MRPs as evidence of the utilities' exceeding their Commission-approved budgets. AOBA pointed out that: BGE exceeded its approved electric capital investment budget by a cumulative \$475.6 million; BGE exceeded its approved gas capital budget by \$123 million; and Pepco exceeded its forecasted MRP capital spending by \$51.8 million.⁴²⁶

Moving forward, AOBA contends that the Commission cannot rely on forecasts of future costs to set just and reasonable rates when subsequent filings show large deviations from those forecasts.⁴²⁷ Further AOBA argues that "given the utilities have demonstrated [an] inability to forecast future expenditures with reasonable accuracy, the notion that the MRP process would reduce regulatory burdens has been soundly debunked."⁴²⁸ AOBA recognizes that some variation for changing situations may occur at times, but the significant level of the utilities' deviations exhibited from the forecasted data in the MRPs to date goes far beyond reason.⁴²⁹ AOBA expressed particular concern regarding: (i) the incentives Maryland MRPs have created for aggressive capital spending; (ii) the erosion of

⁴²³ *Id.* at 7.

⁴²⁴ *Id.* at 10.

⁴²⁵ *Id.*

⁴²⁶ *Id.* at 11.

⁴²⁷ *Id.* at 3.

⁴²⁸ *Id.* at 4.

⁴²⁹ *Id.* at 5.

essential ratepayer protections under MRPs; and (iii) the utilities' undermining of Commission efforts to ensure the affordability of electric service for all sizes and types of Maryland consumers."⁴³⁰ Therefore, AOBA recommends that the Commission find that MRPs have not served the interests of Maryland ratepayers.⁴³¹

AOBA recognizes that BGE's proposed ERSB attempts to address some of the deficiencies, but AOBA argues that proposal "is woefully insufficient."⁴³² AOBA argues that the proposal attempts to circumvent a prudency determination, and result in a variance analysis where the utility has sole control of the inputs.⁴³³

Regarding the NGEA provisions in PUA § 4-213, AOBA argues that the statute's customer-benefit requirement and prohibition on reconciliation as confirmation of many of its criticisms.⁴³⁴ Nevertheless, AOBA still concludes that abandoning the forecast-based MRP construct rather than attempting to repair it best serves the Maryland ratepayers and the public interest. Nonetheless, AOBA expressed that if the Commission decides to continue with MRPs in some fashion, it should only do so on a case-by-case basis that takes into account each utility's individual characteristics and customer mix rather than adopting generic MRP policies.⁴³⁵

c. MEAC

MEAC recommends terminating BGE's pilot and returning to traditional ratemaking, principally because of the impact on limited-income households.⁴³⁶ MEAC

⁴³⁰ *Id.* at 6.

⁴³¹ *Id.* at 7.

⁴³² *Id.* at 23.

⁴³³ *Id.*

⁴³⁴ AOBA Updated Brief at 6.

⁴³⁵ AOBA Final Brief at 14.

⁴³⁶ MEAC Comments at 1.

argues that the MRP construct opens the door for after-the-fact rate reconciliations and appears to be placing the rate risk on consumers while traditional rate making avoids these reconciliations.⁴³⁷ MEAC also highlights the Maryland General Assembly's adoption of new MRP provisions that place guardrails on the process, ensuring that MRPs can only be used in the case of consumer benefits.⁴³⁸ However, MEAC regards "consumer benefits" as too vague because almost any investment might ultimately be characterized as providing some consumer benefit. Ultimately, MEAC recommends that the Commission terminate the pilot, slow rate increases, and return to traditional ratemaking, which would make consumer bills affordable.

d. Ceres

Ceres urges the Commission to immediately terminate the MRP pilot program initiated in 2020.⁴³⁹ Ceres argues that evidence from BGE's implementation demonstrates that this ratemaking mechanism has fundamentally failed to protect Maryland ratepayers, while creating incentives for excessive utility spending.⁴⁴⁰ The organization credits the MRP for unprecedented rate increases while simultaneously reducing regulatory oversight and shifting financial risk from shareholders to consumers.⁴⁴¹

Ceres argues that the pilot has removed important mechanisms that regulators traditionally use to control wasteful spending and ensure prudent investment decisions.⁴⁴² Without these tools, utilities face minimal consequences for inefficient or unnecessary

⁴³⁷ *Id.*

⁴³⁸ *Id.*

⁴³⁹ Ceres Comments at 1.

⁴⁴⁰ *Id.*

⁴⁴¹ *Id.*

⁴⁴² *Id.* at 2.

spending. The Commission and stakeholders have limited visibility into actual spending patterns and whether investments deliver promised benefits to ratepayers. Ceres contends that under the pilot, BGE has transformed what should be an "opportunity to profit" into a virtual "profit guarantee."⁴⁴³ Ceres further argues that this shift fundamentally alters the risk-reward balance in favor of shareholders at the expense of ratepayers.⁴⁴⁴ Ceres urges the Commission to act decisively to restore balance, accountability, and affordability to Maryland's utility regulation framework.⁴⁴⁵

e. Maryland PIRG Foundation

During the first day of the Lessons Learned hearings, a representative for Maryland PIRG Foundation ("Maryland PIRG") argued that the Commission should end the MRP Pilot and return to traditional ratemaking. Maryland PIRG stated that "the pilot has led to excessive rate hikes for 1.3 million Marylanders using BGE as well as customers of other utilities."⁴⁴⁶ Maryland PIRG asserted that ending the pilot does not mean that the Commission will not have the tools it needs to require utilities to engage in long-term planning or meet State policy goals.

Maryland PIRG testified that there were four reasons why the MRP Pilot should end. First, Maryland PIRG argued that "the pilot has led to excessive rate increases without a measurable increase in public benefit."⁴⁴⁷ Citing OPC's data, Maryland PIRG pointed out that since approval of BGE's pilot, BGE's electricity delivery rates have increased 26

⁴⁴³ *Id.* at 3.

⁴⁴⁴ *Id.*

⁴⁴⁵ *Id.*

⁴⁴⁶ Hr'g. Tr., Case Nos. 9618 and 9645, Vol 1, 7:13–17 (Oct. 15, 2024).

⁴⁴⁷ *Id.* at 8:11–17.

percent and gas delivery rates have increased 43 percent and argued that the increases far outpaced the rate increase before the pilot. Second, Maryland PIRG contends that “[a]llowing the utilities to request their approval for rate increases in advance of spending has reduced oversight and accountability, and the transparency benefits have been limited at best.”⁴⁴⁸ Third, Maryland PIRG stated that “the preapproval of spending combined with the reconciliation process has supercharged the incentive for infrastructure spending.”⁴⁴⁹ Maryland PIRG indicated that this combination allows utilities to overspend their budget and still have a virtual profit guarantee, which it claims would not happen in a competitive market situation nor under the traditional ratemaking model. Finally, Maryland PIRG argued that “the impact on rates and profit guarantee is crowding out more valuable programs” like renewable energy, energy efficiency, and building and transportation electrification.⁴⁵⁰ Maryland PIRG concludes that the Commission should end the pilot and return to a ratemaking process that provides better checks on utility spending.

f. Economic Action Maryland

During the first day of the Lessons Learned hearings, a representative from the Economic Action Maryland noted that the organization’s July 2024 member survey showed that “nearly 500 Marylanders, over half of respondents indicated that high utility bills go within their top five biggest costs affecting their lives” and twenty percent of the respondents discussed how they have cut back on utility use in order to cope with the increased cost of living.⁴⁵¹

⁴⁴⁸ *Id.* at 8:19–22.

⁴⁴⁹ *Id.* at 8:23 and 9:1–4.

⁴⁵⁰ *Id.* at 9: 9–18.

⁴⁵¹ *Id.* at 10:22 and 11:1–5.

Economic Action Maryland commented that as climate change leads to hotter summers, “it is imperative that all people are able to afford the electricity needed to cool their homes” and argued that utilities must take the necessary steps to move toward the State’s climate goals.⁴⁵² Economic Action Maryland argues that the MRP pilot model allows BGE “to socialize the cost of infrastructure spending while reaping all the benefits and profits for shareholders.”⁴⁵³ It further asserted that “[a]s a monopoly BGE holds disproportionate control and power over its customers, because few alternatives exist. It is critical that any ratemaking proposals are subjected to rigorous scrutiny and due diligence.”⁴⁵⁴

3. Implement Substantial Reforms to current MRP framework

a. *Staff*

Staff argues that the MRP Pilot as currently structured must be improved by adopting many of the recommended changes by various parties in the Lesson Learned proceeding or it will fail.⁴⁵⁵ For instance, Staff highlighted the limited quantitative information on project benefits and spending, provided by the utility with the MRP Pilot application. Staff argues that this causes asymmetries of information and impedes the review of MRP projects.⁴⁵⁶ Staff recommended substantially enhanced filing requirements to the MRP application process that address the major deficiencies identified by the parties; stronger project-benefit documentation, better explanations of budget-to-actual changes;

⁴⁵² *Id.* at 11:14–17.

⁴⁵³ *Id.* at 12: 4–6.

⁴⁵⁴ *Id.* at 12: 6–10.

⁴⁵⁵ Staff Brief at 6.

⁴⁵⁶ *Id.*

and more robust reconciliation testimony.⁴⁵⁷ Staff argued that a stronger cost-sharing and cost containment mechanisms were needed, but did not endorse BGE’s ERSM proposal.⁴⁵⁸ Staff recommended that parties have further discussions and attempt to reach a consensus proposal for Commission review.⁴⁵⁹

Staff noted that with the comments filed by the parties, the legislative-style hearings conducted on October 15 and 16, 2024, and the filing of briefs by the parties, “a determination could be made under the criteria specified in PUA § 7-505 (c)(2) by the Commission as to whether the MRP Pilot Program should be transitioned into a standard ratemaking process available to gas and electric companies.”⁴⁶⁰ Staff highlighted that “[e]ssentially, there has been at this point of the MRP Pilot Program approximately nine utility-years of experience with MRPs, a much longer period than was contemplated at the commencement of the MRP Pilot Program.” Staff argues that “it is unlikely that any important previously unidentified lessons learned issues will be identified by continuing the MRP Pilot Program for additional three-year MRP periods for any of these utilities [BGE, Pepco and DPL].”⁴⁶¹ Therefore, Staff recommended that the Commission give consideration to whether the MRP Pilot Program should conclude without further use of MRPs or if the MRP Pilot Program should transition and be authorized as a standard form of rate regulation.⁴⁶² Staff cautioned that “if MRPs are authorized as a standard form of alternative regulation, the utilities should remain aware that the use of the MRP process is

⁴⁵⁷ *Id.* at 6-10.

⁴⁵⁸ *Id.* at 10.

⁴⁵⁹ *Id.*

⁴⁶⁰ *Id.* at 13.

⁴⁶¹ *Id.* at 11.

⁴⁶² *Id.*

a privilege, not a right, and that a grant of an MRP would not create an entitlement to a future MRP.”⁴⁶³

Staff noted that MRP regulations will be needed if the Commission intends to authorize the MRP process as a permanent form of alternative ratemaking used by gas and electric companies.⁴⁶⁴ Staff explained that while it may have been appropriate for the Commission to allow use of the specified guidelines and requirements for MRP applications during the pilot, it will be necessary to adopt regulations before MRPs can be adopted as an authorized method of alternative ratemaking for gas and electric companies. Staff explained, “Since the MRP procedures would be applicable to all gas and electric companies, the promulgation of the requirements to be followed cannot be by Commission order but instead must be made by adopting new regulations.”⁴⁶⁵ Consequently, the Commission will need to direct that proposed regulations be drafted and initiate a rulemaking for new MRP regulations prior to ending the MRP pilot.⁴⁶⁶

In its Updated Brief filed September 5, 2025, Staff commented that it does not believe a modified construct involving a shared earnings approach runs afoul of the ban on reconciliations of costs.⁴⁶⁷ The shared earnings approach does not reconcile budgeted costs to actual costs, so in a strict sense it does not involve reconciling programmatic data from the utilities. Staff argued that “a properly constructed sharing model presents an opportunity to instill appropriate utility behavior that allows the organization to perform

⁴⁶³ *Id.*

⁴⁶⁴ *Id.* at 13.

⁴⁶⁵ *Id.* at 14.

⁴⁶⁶ *Id.* at 14-15.

⁴⁶⁷ Staff Updated Brief at 5.

its required functions while reigning in costs in a manner that is equitable for consumers.”⁴⁶⁸

Staff also suggested that the MRP construct should be reformed to extend MRP rates past the end of the MRP. Staff noted that the current construct establishes “a bit of overkill” by requiring utilities and stakeholders to constantly re-examine the existing utility rates prior to the termination of the MRP period. Under the current MRP construct, this process establishes a cycle of perpetual rate cases that results in a utility being forced to file a new rate case at least every 3 years.⁴⁶⁹ Staff further recommended that the Commission determine if an electric company with an approved MRP can still use the BSA under PUA § 4-213.⁴⁷⁰ Staff argued that “[b]ecause the BSA functions as a reconciliation of cost or revenue variances, the BSA may no longer be permitted under Maryland law as it violates the prohibition under § 4-213 against companies with MRPs filing for a reconciliation of cost or revenue variances.”⁴⁷¹

Ultimately, while Staff concludes that the current MRP construct has some significant deficiencies, it does not recommend abandoning forward-looking ratemaking. Staff indicated that a reformed MRP construct could potentially become a standard alternative form of regulation if recommendations from parties participating in the Lessons Learned Proceeding are adopted.

⁴⁶⁸ *Id.*

⁴⁶⁹ *Id.*

⁴⁷⁰ *Id.* at 6.

⁴⁷¹ *Id.* at 10.

b. MEA

In its Initial Brief, MEA recommended that the Commission suspend MRPs “indefinitely unless and until future MYPs—or other forms of alternative ratemaking—meet threshold objectives to guard against harm to customers and to effectively and efficiently plan for State policy goals.”⁴⁷² MEA argued that any approved MRP should have the following safeguards: “(1) Customer benefits must be effectively demonstrated and quantified in each MYP, including ratepayer cost savings; (2) The MYP process should provide an overhauled reconciliation proceedings that is based on stakeholder input; (3) An MYP cost recovery cap or modified earnings share mechanism must be formulated to assure utility spending is within approved limits; and (4) The MYP process must provide for clear and full plan to address of key State policy decisions, including pending policy rulings.”⁴⁷³

MEA claims that the MRP does not go far enough to assure that continuing with the MRP construct is in the public interest.⁴⁷⁴ MEA points out that under PUA § 7-505(c)(2), AFORs, such as MRPs, are completely within the Commission’s discretion and not a matter of a utility’s right.⁴⁷⁵ MEA notes that “PUA § 7-505(c)(2) provides that the Commission “may adopt an alternative form of regulation . . . if the Commission finds, after notice and hearing, that the alternative form of regulation: (i) protects consumers; ensures quality, availability, and reliability of regulated services; and is in the interest of the public, including shareholders of the electric company.””⁴⁷⁶ MEA emphasizes that to be consistent

⁴⁷² MEA Initial Brief at 2.

⁴⁷³ *Id.*

⁴⁷⁴ *Id.* at 4.

⁴⁷⁵ *Id.*

⁴⁷⁶ *Id.*

with PUA § 7-505(c)(2), an MRP application must demonstrate how it “protects consumers” and argues that the Lessons Learned proceeding reveals that the current MRPs have fallen short.⁴⁷⁷

Additionally, MEA recommends a complete overhaul of the reconciliation component in the MRP framework as currently constructed.⁴⁷⁸ MEA argues that to assure strong ratepayer protections as part of an MRP, the annual reconciliations “must be overhauled to incorporate stakeholder input and implemented to effectively contain costs and provide a clear understanding of what is included in the final prudency review.”⁴⁷⁹ MEA argues that the current process does not meet this threshold test.”

MEA also expressed support for stronger cost controls, but does not support BGE’s ERSM proposal as currently designed.⁴⁸⁰ MEA indicated that this type of 50% cost sharing proposal “does not provide a reasonable balance as it favors utilities over customers,” “does not incentivize extraordinary behavior or advance particular policy goals” and it does not quantify benefits or link a utility’s reward to anything other than controlling costs or possibly reaping a windfall from increased operating income.⁴⁸¹

MEA noted that there are a wide range of earnings share mechanisms in other states and suggested that the Commission open a separate docket for stakeholder comments before adopting one. MEA listed several states, such as Hawaii, Vermont and Wisconsin, with approved cost sharing mechanisms that vary widely. Due to the complexity of these mechanisms, MEA supports the Commission initiating a lessons learned inquiry that

⁴⁷⁷ *Id.* at 4-5.

⁴⁷⁸ *Id.* at 5.

⁴⁷⁹ *Id.* at 6.

⁴⁸⁰ *Id.* at 6-8.

⁴⁸¹ *Id.* at 7.

addresses cost sharing experiences with other states, “especially one that answers the question of how much, if any, has actually been credited back to other customers; if the experience in states with both an earnings share mechanism and an MYP have resulted in contained costs, and how an earnings share mechanism compares to performance incentive mechanisms.”⁴⁸²

Regarding the NGEA, MEA stated that it believes that the restriction on reconciliation alleviates some of the escalating costs of the MRP cost recovery and addresses a major issue with the current MRP construct, which was largely agreed upon by the parties as problematic.⁴⁸³ MEA argues that the MRP process can still be valuable as a forward-looking tool to align rate cases with State goals on system planning and grid optimization.⁴⁸⁴ For example, MEA commented that MRPs can provide enhanced regulatory oversight and transparency by allowing the Commission and stakeholders to see utility plans ahead of time and to gauge the accuracy of spending and load forecasts.⁴⁸⁵

MEA pointed out:

Maryland is also facing a whirlwind of competing pressures on its utilities, distribution grid and regulatory structures [] including price increases in PJM capacity auctions; resource adequacy challenges exacerbated by uncertainty surrounding offshore wind and other renewable generation assets; ongoing rate increases based on investments in the distribution system; load growth from data centers and electrification; and worsening affordability pressures on households struggling under energy burdens.⁴⁸⁶

⁴⁸² *Id.* at 8.

⁴⁸³ MEA Updated Brief at 2-4.

⁴⁸⁴ *Id.* at 4.

⁴⁸⁵ *Id.*

⁴⁸⁶ *Id.* at 5.

MEA argued that “[a]ll of these circumstances, combined with the MYP’s shift to concurrent cost recovery, create the need for the state to re-examine traditional cost of service rate-making.”⁴⁸⁷

Finally, MEA recommended that the Commission reconsider the relationship between risk and utility returns in any forward-looking MRP framework in the future. Specifically, MEA asks whether an MRP reduces utility risk through accelerated or concurrent cost recovery and if so, should the utility receive a lower ROE. Therefore, MEA makes several recommendations that the Commission could examine to address the reduced risk from concurrent recovery, such as:

- (1) the Commission could split return OF (*i.e.*, the pass-through costs of plant in service) and return ON (*i.e.*, the rate of return as calculated by the authorized rate of return) by providing for concurrent return only OF spending as certain investments are placed in service, while delaying the return ON the investment until after a prudence review;
- (2) should the Commission adopt the earnings share mechanism approach (“ESM”), the Commission could adjust the relative risk between utilities and ratepayers on certain investments by having an asymmetric recovery, such as a reduced or eliminated recovery for underearning but still including cost sharing for any overearning. Alternatively, a larger deadband to trigger recovery of underearning would similarly reduce the risk placed on ratepayers. At a minimum, any ESM mechanism must appropriately account for the interactions of risk reduction and rate impacts of the bill stabilization adjustment (BSA); and
- (3) ...[D]ecide on a case-by-case basis whether a downward adjustment is necessary given the decreased risk to a utility from multi-year rate plans or financing riders for certain investments. While this type of inquiry can be done in individual rate cases, the goal is to avoid creating a surprise where utilities are suddenly attempting to meet new regulatory expectations. A non-rate case process to explore this issue will likely produce a more measured outcome that utilities can better incorporate into their planning and rate case filings.⁴⁸⁸

⁴⁸⁷ *Id.*

⁴⁸⁸ *Id.* at 8.

c. Constellation

Constellation expresses criticism of the existing MRP but remained open to retaining a substantially redesigned version. It concludes that BGE's pilot has not delivered the promised benefits of rate predictability, better alignment with Maryland energy policy objectives, efficiency or utility innovation. Constellation argues that the MRP “has led to higher than anticipated rate increases, insufficient transparency into utility spending, and concerns regarding the equitable distribution of financial risks between BGE and its customers.”⁴⁸⁹

Constellation argues that to better protect ratepayers and support State policy goals, it is necessary for the Commission to consider reforms to the current MRP construct by incorporating more rigorous mechanisms for evaluating utility forecasts, implementing real-time performance monitoring, and introducing annual reconciliation mechanisms. Constellation believes these types of reforms can enhance transparency, accountability, and the overall effectiveness of the MRP.⁴⁹⁰

d. Baltimore City Councilmember Zeke Cohen’s Office

During the first day of the Lessons Learned hearings, a representative for Baltimore City Councilmember Zeke Cohen’s office commented that their office has followed the MRP case proceeding closely given the significant interest and impact on constituents. The representative noted that not only are BGE’s unprecedented levels of gas infrastructure spending pushing already unaffordable utility rates higher but the gas infrastructure work

⁴⁸⁹ Constellation Initial Comments at 5.

⁴⁹⁰ *Id.*

has substantial impacts on the quality of life to the communities.⁴⁹¹ The representative commented that although rate predictability was one of the intended goals of the MRP, the reality of how residents interact with their utility bills differs from how parties have described. Essentially, residents are not checking the Commission’s website to see what their rates will be in three years because it does not matter “if the rates are predictable if the prediction is that they are skyrocketing.”⁴⁹² The representative concluded that based on the comments from stakeholders, it appears that the MRP primarily benefited BGE but their office believes that there is potentially a solution that gives the benefits to contractors, minority contractors, local businesses, while being beneficial to customers, the planet and the public interest in general.⁴⁹³

4. Specific Modifications proposed by the Parties

During the Lesson Learned proceeding, several parties made recommendations for consideration to improve the MRP framework as structured. Those recommendations have been grouped by category and are listed below.

a. Prefiling Requirements

(1) A Pilot MRP should file a notice that it intends to file an application, which would allow the Commission to schedule when the filing will occur based upon its administrative calendar. This will prevent the simultaneous filing of MRP applications and its adverse impact on the ability of other parties to evaluate the applications.⁴⁹⁴ (Staff)

⁴⁹¹ Hr’g. Tr., Case Nos. 9618 and 9645, Vol. 1, 19:23–20:1-5 (Oct. 15, 2024).

⁴⁹² *Id.* at 21:1–4.

⁴⁹³ *Id.* at 21:5–12.

⁴⁹⁴ Staff Initial Brief at 6.

(2) Any utility planning to file an MRP should file a notice of intent at least 15 days prior to the planned filing date. The notice of intent should include notice of any unusual, innovative or non-recurring proposals in the MRP, including but not limited to proposals such as depreciation rate changes, pilots, and performance incentive metrics.⁴⁹⁵ (Joint Exelon Utilities)

(3) A notice of intent should not replace pre-filing meetings that utilities should continue to offer to Staff and OPC that offer an opportunity for additional pre-filing discussions.⁴⁹⁶ (Joint Exelon Utilities)

(4) Revised Filing Details (Staff)

- (a) Each project above a specified dollar threshold should include a listing of the quantitative benefits the project is expected to achieve. This list will assist other parties and the Commission in understanding the need for the project and how it complies with State policy goals.⁴⁹⁷ (Staff)
- (b) Each project should break down the resources that are expected to be utilized into labor, materials, and outside costs. This itemization will assist parties and the Commission in understanding the actual spend and any variances reported in the Annual Informational Filings.⁴⁹⁸ (Staff)
- (c) Detailed written testimony in support of projects above a certain threshold should accompany the MRP Application. This is a necessary action in establishing the necessity of the projects, and part of the prudence review process. As noted during the Pilot MRP Lessons Learned Proceeding, a portion of the prudence review is front-loaded as a result of the MRP process.⁴⁹⁹ (Staff)
- (d) Projects and spending (both Capital and Operations and Maintenance) should be classified into significant categories that are driving Pilot Utility business decisions. This will assist in showing how the MRP is directing utility spending consistent with State policies.⁵⁰⁰
 - (i) Appropriate categories would include Reliability, Asset Replacement, New Business, Customer Service, Legislative

⁴⁹⁵ BGE Initial Brief at Attachment 1.

⁴⁹⁶ *Id.*

⁴⁹⁷ Staff Initial Brief at 7.

⁴⁹⁸ *Id.*

⁴⁹⁹ *Id.*

⁵⁰⁰ *Id.*

Requirements, Administration, *etc.*⁵⁰¹ (Staff)

- (ii) No amount of actual spend should be classified in a Miscellaneous category account in the Annual Project List or in any schedule of project costs for the year without explanation.⁵⁰² (Staff)

(5) Revised Details of Filing. (Joint Exelon Utilities)

- (a) Capital and O&M projects with spend more than \$10 million or 5% of the annual capital or O&M spend for a given year should be discussed in written testimony by a sponsoring witness.⁵⁰³
- (b) Utilities will include quantification of benefits for projects \$1 million or greater where available and discussion of benefits where quantification is not available.⁵⁰⁴
 - (i) The Exelon Utilities commit to detailed discussions with Staff where they will discuss available benefits at a project-by-project level.

(6) An allowance for major storm recovery costs should be included in the MRP forecast years. Currently, there is no allowance for this cost, so when there is a storm, the MRP spend for that year will exceed the approved budget, and after three years will likely cause a significant variance. An allowance based upon the average cost over the prior five years would provide a fair estimate of the annual cost over a three-year forecast period.⁵⁰⁵ (Staff)

(7) Only approve rate case expenditures that incorporate distribution system planning. (MEA)⁵⁰⁶

If a utility also has a Distribution System Plan (DSP) either approved or under review, the MRP filing should explain how the proposed projects align with the DSP.⁵⁰⁷

⁵⁰¹ *Id.*

⁵⁰² *Id.*

⁵⁰³ BGE Initial Brief at Attachment 1.

⁵⁰⁴ *Id.*

⁵⁰⁵ Staff Initial Brief at 7.

⁵⁰⁶ MEA Initial Comments at 6.

⁵⁰⁷ BGE Initial Brief at Attachment 1.

(Exelon)

Incorporate a more rigorous mechanism for evaluating utility forecasts and capital investments to ensure they meet State objectives.⁵⁰⁸ (Constellation)

(8) Limit use of electronic only data responses.⁵⁰⁹ (AOBA)

(9) Require detailed project-level analysis rather than broad program-level forecasts.⁵¹⁰ (Constellation)

(10) If a party recommends or requests that any Pilot Utility programs or projects be removed from consideration during the MRP application approval process because that program or project is better regulated in a different proceeding, the State policy or goal associated with that program or project should be identified along with an explanation as to how this would better accomplish that State policy or goal.⁵¹¹ (Staff)

(11) Utilities should offer meetings with stakeholders throughout the MRP procedural schedule on key topics, such as meetings explaining the utility's budgeting process, overviews of different projects, or other topics as requested by stakeholders. Such meetings would include utility subject matter experts who would be available to answer stakeholder questions.⁵¹² (Joint Exelon Utilities)

(12) Length of time for MRP effective period?

(a) Utilities would continue to be allowed to file MRPs for a period up to 3 years.⁵¹³ (Joint Exelon Utilities)

⁵⁰⁸ Constellation Initial Comments at 2.

⁵⁰⁹ AOBA Initial Brief at 18.

⁵¹⁰ Constellation Initial Comments at 2.

⁵¹¹ Staff Initial Brief at 8.

⁵¹² BGE Initial Brief at Attachment 1.

⁵¹³ *Id.*

b. Rate Case Length and Commission Flexibility

(1) Establish procedural requirements to prevent simultaneous litigation of multiple MRP applications⁵¹⁴ (Staff)

c. Post Case Filings (Project Lists and Annual Informational Filings)

(1) Adjust project list to be more consistent with Annual Informational Filing and include supplemental information to support any new projects greater than \$1 million to lessen parties' administrative burden.⁵¹⁵ (Joint Exelon Utilities)

- (a) Supplemental information would include a breakdown of project costs by labor, contracting, materials and other.
- (b) Annual project list updates should note any new or canceled projects greater than \$1 million, with reasons for the addition or cancellation.
- (c) Projects should be noted if they have spend going into service during the MRP period and the year it is forecasted to go into service.
- (d) Any miscellaneous or other categories should contain detail on any projects with spend of \$500,000 or greater.

(2) Monitoring the status of MRP projects⁵¹⁶ (Staff)

- (a) MRP filings and updates should include discussion of changes from initial budget to those reflected in the current or updated Project List. This is necessary to determine whether the forecast spend for any projects or programs in any coming forecast years will need to be adjusted to comply with the MRP budgets and the approved tariff rates. (Staff)
- (b) Mid-Year Reports should discuss any changes to the Project List implemented for the Year. (Staff)
- (c) The Annual Information Filing should show which projects have closed and those projects that have been deferred from their planned year along with the reason for the deferral. (Staff)

(3) For parties to consider. Should there be a limit on how much cost shifting

⁵¹⁴ Staff Initial Brief at 6. *See also* Staff Reply Comments at 5.

⁵¹⁵ BGE Initial Brief at Attachment 1.

⁵¹⁶ Staff Initial Brief at 8.

between projects can occur before rates should be lowered automatically for a utility's failure to stick to the reviewed project and budgets?

- (a) MEA on brief indicated that utilities should not be allowed to swap out projects.⁵¹⁷ AOBA raises concerns about utilities shifting budgets significantly.

d. Timing of Next Case

(1) Future MYPs would not include an expiration date for the Year 3 rates.⁵¹⁸ End or revisit the requirement for rate expiration and the obligation to file a subsequent rate case to provide flexibility as to when cases may be brought forward in a manner that seeks to balance the workload of stakeholders to the extent possible. (Joint Exelon Utilities and Staff)

e. Reconciliations and Incentive Mechanisms

(1) Filing

- (a) Require more detailed explanations to support reconciliation requests.
 - (i) MEA- Utility should clearly identify what work items from the budget / Project List have been closed and moved into Plant accounts by Project. Supporting testimony must identify and explain the changes that have occurred to the Projects set forth in the Annual Project List and the reason for the change. (Staff)
- (b) Utility should quantify whether the intended benefits from Projects were achieved and, if not, why they were not achieved.⁵¹⁹ (Staff)
- (c) Final annual costs should be broken into component resources such as labor, materials, and outside costs and an explanation as to differences than those set out in the original Project List and as modified in subsequent Annual Informational Filings.⁵²⁰ (Staff)
- (d) Utilities should provide a schedule that shows the work items and

⁵¹⁷ MEA Initial Brief at 6.

⁵¹⁸ BGE Initial Brief at Attachment 1.

⁵¹⁹ Staff Initial Brief at 9.

⁵²⁰ *Id.*

projects from the Project List that have closed and the spend moved into Plant accounts since the last approved Plant balance.⁵²¹ (Staff)

- (e) Utilities should provide detailed testimony that shows that the final spending for the year for capital and O&M costs is both reasonable and efficient.⁵²² (Staff)

(2) Incentive Mechanisms

(a) Performance Incentive Mechanisms

- (i) MEA in its initial filings suggested that PIMs be explored further.⁵²³ Over the course of the MRP, the utilities either withdrew or the Commission denied all PIMs.

- (ii) IBEW opposes PIMs.⁵²⁴

(b) Cost Sharing Mechanism (Joint Exelon Utilities)

- (i) Future MRPs should include an earnings sharing mechanism, with a symmetrical deadband above and below the Commission-authorized rate of return. If the utility's annual earned rate of return is within the deadband, there is no amount which would run through the MRP Adjustment Rider. If the utility's annual earned return is above the deadband, the utility will share 50% of the amount above the deadband with customers through the MRP Adjustment Rider. If the utility's annual earned return is below the deadband, the utility has the opportunity to seek recovery of 50% of the amounts below the deadband lower range could be recovered through the MRP Adjustment Rider. Annual informational filings presenting all annual results would continue to be filed and include ESM calculations.⁵²⁵

- (ii) Supported by the Exelon Utilities and Constellation. Staff indicated some support for it but presented a different proposal as to how it would work.

- (1) MEA did not support but recommended the Commission look into it further. Wants stakeholders to formulate a cost recovery cap, PIM, or earnings sharing mechanism that appropriately incentivizes utilities to manage costs.

- (2) Put a cap on additional revenue that can be obtained.⁵²⁶ (Staff, MEA)

⁵²¹ *Id.*

⁵²² *Id.*

⁵²³ MEA Initial Comments at 5.

⁵²⁴ IBEW Initial Comments at 3.

⁵²⁵ BGE Initial Brief at Attachment 1.

⁵²⁶ MEA Initial Brief at 6.

(3) Require utilities to provide a “Schedule of Affiliate Transactions” report.⁵²⁷ (IBEW)

(4) Allow new parties to join the case for a limited time at time of reconciliation filing.⁵²⁸ (IBEW)

f. Miscellaneous

(1) Establish a deferred accounting mechanism for unanticipated and material costs that arise.⁵²⁹ (Exelon Utilities)

(2) Docket a proceeding or set a procedural schedule inviting interested parties to comment about whether the language of PUA § 4-213 prohibits further application of the BSA under the MRP.⁵³⁰ (Staff)

(a) Staff and other parties questioned if the BSA was not allowed for utilities using an MRP because of the prohibition on reconciliation.

(3) Examine how ROEs are applied (MEA)⁵³¹

(a) The Commission could split return OF (*i.e.*, the pass-through costs of plant in service) and return ON (*i.e.*, the rate of return as calculated by the authorized rate of return) by providing for concurrent return only OF spending as certain investments are placed in service, while delaying the return ON the investment until after a prudency review.

(b) Should the Commission adopt the ESM approach, the Commission could adjust the relative risk between utilities and ratepayers on certain investments by having an asymmetric recovery, such as a reduced or eliminated recovery for underearning but still including cost sharing for any overearning. Alternatively, a larger deadband to trigger recovery of underearning would similarly reduce the risk placed on ratepayers. At a minimum, any ESM mechanism must appropriately account for the interactions of risk reduction and rate impacts of the bill stabilization adjustment

(c) The Commission could decide on a case-by-case basis whether a

⁵²⁷ IBEW Local 410 Initial Comments at 2-3.

⁵²⁸ *Id.*

⁵²⁹ BGE Initial Brief at Attachment 1.

⁵³⁰ Staff Updated Brief at 10.

⁵³¹ MEA Updated Brief at 8.

downward adjustment is necessary given the decreased risk to a utility from multi-year rate plans or financing riders for certain investments. While this type of inquiry can be done in individual rate cases, the goal is to avoid creating a surprise where utilities are suddenly attempting to meet new regulatory expectations. A non-rate case process to explore this issue will likely produce a more measured outcome that utilities can better incorporate into their planning and rate case filings.

(4) Storm costs have been a significant driver of MRP reconciliations. If utilities are operating in an MRP, regulatory asset/liability treatment should be provided for increases or decreases in minor storm costs, similar to the current treatment of major storm events. Storms are an item commonly included in the definition of exogenous costs by other states and are largely outside of a utility's control. If the Commission does not prefer a regulatory asset or liability, it should alternatively add an exogenous cost adjustment to the ERSM.⁵³² (Joint Exelon Utilities)

(5) New regulatory and legislative requirements, which were not included in the initial MRP base rates but arise during the MRP period, should be dealt with in individual Commission proceedings. The Commission should provide appropriate cost recovery treatment of any related programs in those proceedings.⁵³³ (Joint Exelon Utilities)

g. Demonstration of Benefits to Customers of Investments

This is a new requirement established under PUA § 4-213(b), if an MRP is allowed. This provision was not significantly addressed in the parties' revised briefs, and it is recommended that this be examined by the parties. OPC's view is that utilities likely cannot meet this requirement. MEA recommended that MRPs be suspended until the utilities can demonstrate and quantify customer benefits, including ratepayer cost savings.

⁵³² BGE Initial Brief at Attachment 1.

⁵³³ *Id.*

Commission Decision

Since the Commission's initiation of this MRP Lessons Learned proceeding in August 2024, the Maryland General Assembly has passed two key statutes that materially altered the regulatory landscape related to MRPs and must inform how the Commission addresses the threshold question of what to do with the current MRP framework going forward. First, in May 2025, the Maryland General Assembly passed Senate Bill 937/House Bill 1035, also known as the NGEA, and codified in PUA § 4-213.

Under the NGEA, PUA § 4-213 provided in pertinent part:

- (a) This section applies only to a public service company that is an electric company, a gas company, or a combination gas and electric company.
- (b) Unless otherwise authorized by law, the Commission may approve the use of a multi-year rate plan for distribution base rates **only if** the plan:
 - (1) demonstrates the customer benefits of the investment; **and**
 - (2) does not allow for the public service company to file for reconciliation of cost or revenue variances of the approved revenue component used by the Commission to establish just and reasonable rates.
- (c) A public service company that files or has filed an application for a multiyear rate plan **may not** subsequently file for reconciliation of cost or revenue variances of the approved revenue component used by the Commission to establish the multiyear rates unless the filing for reconciliation was made on or before January 1, 2025.⁵³⁴ (emphasis added)

The NGEA created a heightened test for approval of an MRP by requiring a demonstration of customer benefits and initially restricted a utility from filing for

⁵³⁴ PUA § 4-213(b).

reconciliation of costs or revenue variances of the approved revenue requirement used to establish just and reasonable rates.

Subsequently, in May 2026, the Maryland General Assembly passed the Utility RELIEF Act, which further amended PUA § 4–213 clarifying the cost/revenue variance language by adding PUA § 4–213(d), which states, “For multiyear rate plans approved after January 1, 2026, the Commission **may require** a public service company to include a reconciliation procedure in its multiyear rate plan **to refund customers** the difference between: (1) the public service company’s approved revenue requirement and the public service company’s actual revenue requirement during the term of the multiyear rate plan.” (emphasis added) PUA § 4–213(d) removes the strict prohibition on reconciliation initially enacted and permits the Commission to require a utility to file a reconciliation procedure when the utility has overcollected and customers must be refunded. This provision shapes whether and how cost and/or revenue variances can be handled under an MRP framework. Additionally, the Utility RELIEF Act amends PUA § 7-505, which is addressed in Section III. D. 2 below. Both of these statutes reflected the General Assembly’s concern with increased rates for critical utility service to their constituents.

The Commission finds that the MRP-related provisions of the NGEA and the subsequent Utility RELIEF Act address one of the major points of contention among all parties in this proceeding: *reconciliation*. The enactment of PUA § 4-213 substantially narrows the dispute because future MRPs are now prohibited from using the reconciliation mechanism or cost-sharing mechanisms that result in additional charges to customers above the approved revenue requirement. Additionally, MRPs must demonstrate customer benefits. However, the Commission finds that while the revised statutes provide some

parameters to address one problematic area, they leave several other major issues unresolved that must be addressed if MRPs are to be considered as a standard rate setting tool in the future. A non-exhaustive list of open questions includes, how should customer benefits be defined and demonstrated; determining whether earnings-sharing mechanisms are permissible under the statute or would it be considered a form of reconciliation; how should prudency reviews work without reconciliation; and determining whether the BSA remains appropriate.

With such critical issues remaining, after completing the MRP Pilot, the Commission is unconvinced that the MRP framework as implemented satisfied PUA § 7-505(c)(2) in order to be transitioned into a regular ratemaking process at this time. Also, the Commission finds that PUA § 4-213 necessitates a change to the MRP as currently structured but also leaves open a pathway for MRPs even with the Commission's misgivings. As Ms. Francis, AOBA's Counsel, stated during the October 16, 2024 hearing, "the current [MRP] process doesn't need a little tinkering up or down, it needs a major rehaul or a complete elimination," to which the Commission generally agrees.⁵³⁵ Nonetheless, Maryland statute now expressly provides for MRPs, therefore, a further examination of how the concerns and shortcomings raised in this Lessons Learned proceeding can be addressed is warranted.

In determining the appropriate path for the use of the MRP structure by Maryland's utilities, the Commission believes that a further evaluation based on the lessons learned from the MRP Pilot, as well as the provisions in the recently enacted legislation discussed above, is warranted. Additionally, the Commission finds that even after a substantially

⁵³⁵ Hr'g. Tr., Case Nos. 9618 and 9645, Vol. 2, 327:6–8 (Oct. 16, 2024).

reformed forward-looking MRP framework is developed for consideration, PUA § 4-213(b) grants the Commission discretion to approve use of such a plan for any utility.

The Commission, therefore, directs the Work Group already established in PC 83 to address both the mandated Utility RELIEF Act Study described in the Commission's Notice⁵³⁶ issued on September 10, 2026 and the development of recommendations based on the conclusions contained in this Order. Specifically, the Work Group is charged with developing and recommending a more refined and robust forward-looking MRP framework that addresses issues raised by the implementation of PUA § 4-213 and other concerns raised by the parties in this proceeding. This could include a reexamination of other AFORs as permitted in PUA § 7-505(c) and should also be informed by the mandated study required by PUA § 7-505(c)(4) for which the Commission has already directed a work group to file recommendations on or before February 1, 2027. As noted by BGE, this work group does not have to start from scratch.

The Commission also notes that Pepco already has transitioned away from an MRP and BGE has proposed a rate case that will transition off of projected MRPs for the time being. Parties should track and include in the work group report to the Commission regarding any complications arising from these transitions and how they may be mitigated. The Commission agrees that a place to begin the evaluation is with the work that began in 2019 and 2020 when the MRP was originally being formulated.

The current MRP construct permits any Maryland utility to file an MRP application that is based on a historic test year and may establish rates for up to three future rate-effective years. The application can be filed at any time and must contain certain minimum

⁵³⁶ Notice of Proceeding, PC 83, *RELIEF Act Study* (Sept. 10, 2026).

filing details.⁵³⁷ Order No. 89482 in Case No. 9618 also outlines other requirements for the utility's MRP application testimony and what must be demonstrated. For example, in addition to the filing requirements, the application must include a commitment to remain under the plan during its term ("stay out"), track forecast accuracy, provide annual informational filings, satisfy reporting requirements and adhere to a reconciliation process (which is now expressly prohibited by PUA § 4-213). Order No. 89482 outlined just the minimum requirements; a utility was free to provide additional information or criteria as appropriate.

In terms of the various recommendations made to improve the MRP framework, the Commission will not give explicit guidance on all of these recommendations as they are better left to the Work Group to discuss and examine as to how they can appropriately balance the concerns raised by the Commission and other stakeholders throughout this Order, including but not limited to the need for: increased forthright advanced sharing of critical data and information from utilities, better alignment with ensuring utilities have incentives to control costs, reduced administrative burden, equitable distribution of risk, clear demonstration of customer benefits, clear showing of how State policy objectives are being advanced and addressing any other shortcomings of the MRP identified during this Lessons Learned proceeding. Ultimately, the utilities bear the burden of proof to make these demonstrations and to satisfy statutory requirements to obtain MRPs or other AFORs. It is not the responsibility of other parties to solve this conundrum, though the Commission will provide the forum for productive discussion and negotiations to take place.

⁵³⁷ See Maillog No. 300339, *citing* Case No. 9645—Updated BGE Minimum Filing Requirements, filed Nov. 30, 2022.

The Commission considers all enhancements recommended by the parties in this Lessons Learned proceeding as possible tools to address its concerns and that all proposals should be considered in the Work Group unless otherwise mentioned in this Order. The Work Group shall determine what policies would be appropriate to be implemented as part of a new more refined and substantially reformed forward-looking MRP framework that would satisfy PUA § 7-505(c)(2), § 4-213, §4- 201, and §4-101. As part of its work product, the Work Group is directed to submit an Evaluation Report and Plan identifying those recommendations that achieved consensus and/or non-consensus among the parties participating in the Work Group, including whether the Commission should establish regulations. To help ensure better focused discussions, the Commission shares the following observations.

Regarding pre-filing notices discussed by Staff and the Exelon Utilities, the Commission finds this concept to be acceptable but will not rule on timelines or the content of the pre-filing notices or meetings and directs the Work Group to discuss and recommend appropriate parameters.

Regarding filing requirements with direct testimony, the Commission agrees that the utilities must do a better job of making it clear what projects are associated with the FERC account budgets, provide better justification for the budgets, and generally make it easier for parties and the Commission to understand what is actually being relied upon to set rates, including the in-service date and its actual impact to the requested revenue requirement. Additionally, there needs to be a clearer explanation of what utilities spend as a result of Commission directives or policy goals if those are used as justification for MRPs. As noted previously, the fact that stakeholders must submit more than 2,000 data

requests to have a better understanding of a utility's projects and related expenditures included in its revenue requirement request appears to be a failure of transparency more than a sign of success that the discovery process works as intended. The Commission expects the Work Group to propose remedies that would minimize the need for such data request volume. Additionally, the Commission expects that any reformed forward-looking MRP framework would require utilities to submit enough information with the rate case application to convert it from a forward-looking MRP to a traditional historic test year case with the accompanying testimony.

Regarding rate case length and the Commission's flexibility to stagger the scheduling of utility MRP applications, the current statute allows the Commission up to 300 days to issue a decision from the date of a utility filing for an AFOR.⁵³⁸ Over the course of this proceeding, several parties suggested modifying or extending the statutory deadline to address timing of the rate case application filings or to mitigate rate case stacking, which places a heavy burden on staffing resources—especially the Commission Staff. To address the first issue, Staff proposed that the Commission establish procedural requirements to prevent simultaneous litigation of multiple MRP applications.⁵³⁹ It is unclear to the Commission how this can be accomplished under existing statute. Therefore, the Work Group should make proposals in the February 1, 2027, report as to what legislative changes are needed to provide the Commission this flexibility, or the legal justification the Commission can lean on under existing statute. The subsequent report filed in PC 83 should

⁵³⁸ PUA § 4-204(b).

⁵³⁹ Staff Reply Comments at 5-6.

address what additional Staff resources are needed to appropriately effectuate a revised MRP or AFOR framework.

Regarding post-rate case filings, including project lists and annual information filings, the MRP framework as currently structured requires: (1) project lists be filed prior to the start of the next year, and (2) annual information filings made 90 days after the close of the MRP year and a subsequent 60 day review period, inclusive of parties' ability to request an off-ramp to the MRP.⁵⁴⁰ The parties also have the ability to adjust rates at the Annual Informational Filings. Based on the fact such large spending and project variances occurred in rate-year three of BGE's and Pepco's MRPs, the Commission agrees with OPC that there needs to be a more robust process to address shifting work plans. At a minimum, the Commission finds reasonable the transparency enhancements proposed by Staff including requiring a utility to explain changes between the original budget and those reflected in the current or updated Project List; require mid-year reports to identify project-list changes, and Annual Informational Filings should identify completed projects, and project deferrals, including the reason for deferrals. The Commission directs the Work Group to recommend a process for either review or notification if there is a large variance in either spending or projects from what was approved. A balance needs to be struck between improving transparency into—and appropriate oversight of—shifting budgets and changing costs; versus minimizing administrative burden and avoiding micromanaging utility operations.

Regarding the prescribed timing of subsequent rate cases at the conclusion of a forecasted effective rate period, the Commission agrees with Staff and the Joint Exelon

⁵⁴⁰ Order No. 89482 at 36-40.

Utilities that the Work Group should consider either ending or revising the requirement that rates must expire at the end of this period to balance workload of stakeholders. If utilities are given such flexibility to defer filing new rates, whether by MRP or another type of rate setting paradigm, consideration needs to be given to how this would impact the use of reconciliation processes permitted by PUA § 4-213.

Regarding reconciliation, the current MRP framework requires utilities to include a reconciliation of the first two years of an MRP in rate-year three as part of their next base rate case and submit a reconciliation for the final year of the MRP after the MRP rate effective period. These reconciliation reviews were supposed to serve as the prudence review of the utilities' actual spending. As with post-rate case filings discussed above, the amount of information provided in the initial reconciliation requests during the MRP pilot was problematic, and it was hard to follow how budgets changed or utility spending shifted between accounts. If forecasted test years, in MRPs or otherwise, are permitted in the future, the Work Group needs to ensure that a requirement for clear, navigable testimony outlining in detail how and why projects and budgets changed is included in its proposed MRP or other AFOR framework. There also needs to be a very clear demonstration of how the budgeted spend shifted between FERC accounts from the beginning of the case to the end of the case. The Work Group should explore how prudence reviews and reconciliation or other cost control mechanisms (including cost caps and the BSA) as permitted under PUA § 4-213 would change to ensure just and reasonable rates. Finally, the Work Group should explore what appropriate limits or tools can be used to address the concern that the absence of boundaries on shifting projects and budgets lessened the usefulness of the utilities' forecasts.

Regarding PIMs, the Commission will not address these in this Order other than to note the Commission did not approve any utility proposed PIMs across the five MRP proposals submitted to the Commission. It may be that utilities will use PIMs to demonstrate customer benefits of MRPs in the future. In Order No. 89638, the Commission determined that “for administrative efficiency, only the utility filing a rate case may propose a PIM.”⁵⁴¹ If PIMs are used in future MRPs or forecasted test year cases, the Commission is interested in the Work Group evaluating whether there should be no prohibition upon other parties proposing PIMs.

The Commission notes there were other proposals related to MRPs that do not fit neatly into these categories. As noted previously, the Commission is interested in understanding if there is a more analytical approach to addressing reduction in financial risk to utilities of MRPs and forecasted test years.

C. Next Steps

1. Sunset MRP Pilot

With the legislature's passage of the NGEA, including the new restrictions for the MRP set forth in PUA § 4-213 and PUA § 7-505 (c)(2), the Commission finds that this is the appropriate time to sunset the current MRP Pilot, which was never intended to last beyond the first full MRP cycle inclusive of the MRP reconciliation in order to gain experience and learnings to help formulate appropriate future regulations. As discussed above, a *properly constructed* multi-year rate plan could produce just and reasonable rates; however, the Commission recognizes that the legislature’s adoption of PUA § 4-213 sets

⁵⁴¹ Order No. 89638 at 12.

in place certain guardrails that eliminate key components of the current MRP framework defined in Order No. 89482 and introduces other issues that must be addressed and resolved before moving forward with any next procedural steps required to adopt regulations based on the current MRP framework and making it a regular ratemaking alternative in Maryland.

2. Conduct Mandated Utility RELIEF Act Study

As discussed above in Section III.B., the Maryland General Assembly in May 2026 passed additional legislation, the Utility RELIEF Act, which further clarified that reconciliation could occur in favor of the customer, that cost sharing above the authorized revenue requirement was prohibited, and placed a one-year moratorium on forecasted test years while the Commission completed an additional proceeding evaluating whether forecasted test year, historic test year or a hybrid model is in the best interest of and protects ratepayers. The Commission has already established PC 83 to address this report and the work group shall address both the recommendations and concerns discussed above in Section III. B., and the report established in PC 83.

3. Work Group Recommendation and Report

The Work Group shall create work products under two phases and file corresponding reports. Under Phase 1, the Work Group shall develop a detailed recommendation that addresses the mandated study required pursuant to PUA § 7-505(c)(4), evaluating whether forecasted test year, HTY or a hybrid model is in the best interest of and protects ratepayers and submit a recommendation to the Commission by ***February 1, 2027***. This report may address other topics raised above but should focus on the legislature's required report. To the extent the Work Group believes any of the above

topics may require legislative action, the Work Group should attempt to address this in the February 1, 2027 report. The Commission will take into consideration the Work Group Phase 1 Report when making its final recommendation to the General Assembly as mandated by PUA § 7-505(c)(4) and which must be submitted by ***April 1, 2027***. The Commission anticipates overlap between Phase 2 items and the report mandated under PUA § 7-505(c)(4). After consulting the Work Group, the Work Group leader shall determine what additional items should be addressed by the Work Group report on February 1, 2027, that would help inform the Commission's filing to the General Assembly on April 1, 2027, including if there are possible legislative changes.

Under Phase 2, the Work Group shall develop and submit an Evaluation Report and Plan addressing the other tasks set forth in this Order to determine what modifications could lead to a new more refined and substantially reformed forward-looking MRP framework that would satisfy PUA § 7-505 (c)(2), § 4-213, § 4-201, and § 4-101. The Work Group shall submit its Phase 2 Report by ***June 30, 2027***. The Evaluation Report and Plan should identify whether the recommendations received consensus or non-consensus from the stakeholders.

IV. CONCLUSION

The Commission is charged with setting just and reasonable rates, which strike the proper balance between the interests of utilities, ratepayers, and State policy objectives. In Order No. 89226, the Commission found that the record developed in Public Conference 51 ("PC 51") supported the use of an MRP as an alternative to traditional ratemaking methods and could be pursued under PUA § 7-505(c). The Commission further determined

that a properly constructed MRP can result in just and reasonable rates and yield several benefits over time. Since establishing the MRP framework and selecting BGE as the Pilot utility, the Commission and other stakeholders have had the opportunity to test the current MRP framework and determine whether the intended or expected benefits have materialized over time.

It is the Commission's observation that after nearly five years of experience with multiple utilities beyond the Pilot utility engaging in the MRP process, the intended or expected benefits have not been fully realized. Additionally, the Commission finds it is unlikely—as Staff asserted in its Initial Brief—that any new unidentified lessons learned will be identified by continuing the MRP Pilot Program for another three years. Most significantly, the Commission finds that the passage of the MRP-related provisions of the NGEA and the Utility RELIEF Act have materially altered the MRP regulatory landscape by creating a new requirement for customer benefits and eliminating reconciliations that would increase customer costs.

The Commission observes that, while the revised statutes address one of the most problematic areas (reconciliation), they left several other major issues unresolved that must be addressed if MRPs are to be considered as a standard rate setting tool in the future. The Commission is unpersuaded that the MRP framework as currently structured satisfies PUA § 7-505(c)(2) in order to be transitioned into a regular ratemaking process at this time. Therefore, the Commission is sunsetting the MRP Pilot established in Order No. 89482. As noted above, the Commission finds that with Maryland statute now expressly providing for MRPs, a further examination of how the deficiencies raised in this Lessons Learned proceeding can be addressed is warranted and charges the Work Group established in PC

83 to conduct such examination. To be clear, the Commission finds that any future forward-looking MRP should protect customers from unnecessary or excessive rate increases, enable advancement of Maryland's policy objectives, preserve utilities' financial ability to attract capital on reasonable terms, equitably distribute risks between customers and utilities, maintain forthright and transparent information flows (minimizes asymmetrical information flow), and allow a utility to receive a fair opportunity to earn its authorized return on prudent investments. The Commission expects the Work Group will keep these principles in mind when conducting its examination.

IT IS, THEREFORE, this 1st day of October, in the year of Two Thousand Twenty-Six, by the Public Service Commission of Maryland, **ORDERED:**

(1) that the MRP Pilot initiated in Order No. 89482 is hereby sunset as discussed herein;

(2) that the Work Group established in PC 83 shall be divided into two phases covering the recommendations and reports discussed herein;

(3) that said PC 83 Work Group shall: (a) develop a detailed recommendation that addresses the mandated study required pursuant to PUA § 7-505(c)(4) by *February 1, 2027*, and (b) set forth a new more refined and substantially reformed forward-looking MRP framework that addresses the concerns and recommendations raised by the parties in this proceeding and submit an Evaluation Report and Plan to the Commission by *June 30, 2027*; and,

(4) that the Work Group Recommendations and Evaluation Report and Plan and further filings related to a reformed forward-looking MRP framework shall be filed in PC 83.

/s/ Kumar P. Barve

/s/ Frederick H. Hoover, Jr.

/s/ Bonnie A. Suchman

/s/ Odogwu Obi Linton

/s/ Ryan C. McLean

Commissioners