BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND

Potomac Electric Power Company's Application for Adjustments to its Retail Rates for the Distribution of Electric Energy	Case No. 9702

DIRECT TESTIMONY

OF

ERIC BORDEN

ON BEHALF OF THE OFFICE OF PEOPLE'S COUNSEL

December 15, 2023

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INTRODUCTION

Q. Please state your name and business address.

A. My name is Eric Borden. I am a Principal Associate at Synapse Energy Economics, Inc. (Synapse) located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; ratemaking, rate design, and utility investments; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, the U.S. Department of Energy, the U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 40 professional staff with extensive experience in the energy industry. .

Q. Please describe your educational background and qualifications.

A. I hold a Master's degree in Public Affairs with a concentration in Energy and Environmental Policy from the University of Texas at Austin LBJ School. My undergraduate degree is in finance and entrepreneurship from Washington University in St. Louis. My resume is attached as Appendix A.

Q. Please describe your professional experience.

A. At Synapse, I conduct economic, environmental, and policy analysis of energy system technologies, planning and regulations associated with both supply- and demand-side resources. I have over ten years of experience in the energy and utility regulation space and have testified as an expert witness in multiple jurisdictions across North America. A list of those proceedings is attached in Appendix A.

Q. Have you previously testified in regulatory proceedings before the Maryland Public Service Commission?

A. Yes. I previously testified on behalf of the Office of People's Counsel on matters related to the treatment of the building electrification and non-road electrification cost recovery proposals in Case No. 9692, Baltimore Gas and Electric Company's application for an electric and gas multi-year plan.

Q. Have you previously testified in proceedings before state utility Commissions in other jurisdictions?

A. I have testified on numerous occasions at the California Public Utilities Commission (CPUC) and submitted testimony in multiple other states and Canada, including in Illinois, Maine, Minnesota, Nova Scotia (Canada), South Carolina, and New Hampshire. I have also contributed to projects and testimony on regulated utility issues in New Mexico and New Jersey.

Q. On whose behalf are you appearing?

A. I am presenting testimony on behalf of the Maryland Office of People's Counsel (OPC).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address Pepco's proposals for performance incentive mechanisms (PIMs) as included in its second Multi-Year Plan (MYP) related to reliability, greenhouse gas (GHG) emissions reductions, and removal of equipment with Polychlorinated Biphenyls (PCBs).

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

A. The sources for my testimony are Pepco's Application, in particular the testimony of Witness Schatz, Pepco's responses to discovery requests, public documents and websites, and my personal knowledge and experience.

Q. Was this testimony prepared by you or under your direction?

A. Yes. My testimony was prepared by me or under my direct supervision and control.

I. Summary and Overview of Recommendations

Q. Please summarize your primary conclusions concerning Pepco's Proposed performance incentive mechanisms.

A. Pepco's PIMs are poorly designed, unnecessary, and unlikely to result in ratepayer benefits. Overall, the proposed PIMs would reward the Company for simply spending ratepayer funds on activities it was already planning to undertake to meet targets that are relatively unambitious and easy to accomplish. Further, they do not conform to the Commission's criteria set forth in Order No. 89638. And almost all of the ratepayer funding for which PIMs would be rewarded are capital expenditures, for which Pepco earns a return and thus has sufficient incentive to accomplish.

Q. Can you summarize your conclusions regarding each of the specific PIMs that Pepco has proposed?

A I understand that OPC witnesses Paul Alvarez and Dennis Stephens recommend termination of the MYP. Should the Commission decide to approve the MYP notwithstanding that request, I recommend the following:

1. The reliability PIM should be rejected because:
   - It is easily achievable (and has already been achieved in every year of recorded data);
   - Pepco already has a core public service obligation to achieve high levels of reliability cost-effectively and should not receive additional shareholder rewards to do so.
   - Pepco has sufficient financial incentive to achieve the sought reliability improvements due to its ability to earn a return on the enabling capital investments;

- the Company's benefit-cost analysis shows the program is not cost-effective for residential ratepayers and is even less so with the addition of the PIM reward; and

2. The GHG PIM should be rejected because:

   - The proposal is unsupported and lacks sufficient detail;

   - The reward targets are too easily achievable, contrary to Order No. 89638, and in fact have already been achieved every year since 2017. Further, the penalty thresholds are not meaningful;

   - Pepco has sufficient incentive to pursue these projects as the programs are primarily capital expenditures.

3. The PCB PIM should be rejected because:

   - It is easily achievable;
   - It seeks to reward shareholders for spending ratepayer funding in the manner proposed by Pepco; and
   - Pepco has sufficient financial incentive, and no financial dis-incentive, to accomplish the work.

4. Given the clear conflict of interest demonstrated in the utilities' PIM proposals, the Commission should reconsider its decision in Order No. 89638 that only the utility filing a rate case may propose a PIM. In future MYPs the Commission should allow PIM proposals from intervening parties.[1]

[1] I do recognize that this recommendation has just been adopted in Order No. 90948, Case No. 9692 at 209-210 (Dec. 14, 2023) ("[T]he Commission is persuaded that non-utility proposals may be able to unlock public policy and ratepayer benefits that utilities might not consider. Going forward, the Commission will allow non-utilities to propose PIMs in future rate cases."). My recommendation is being included to complete the record in this case should any modifications to this aspect of Order No. 90948 be reversed or modified.

II. Overview of Performance Incentive Mechanisms

A. The Role of PIMs in Utility Regulation

Q. Please describe the PIM concept and its role in utility regulation.

A. PIMs are intended to encourage utilities to improve their performance with regard to a number of areas of interest, including reliability, service quality, greenhouse gas emissions (GHG's) or other areas that affect customer value. The goal is to create incentives for utilities to operate more effectively and provide better services to customers. PIMs are typically structured to provide a financial reward if the utility achieves a certain goal or metric, or a penalty if the utility fails to meet a performance target. A well-designed PIM helps to align the interests of the utility with the interests of the customers and the public, promoting a more efficient, reliable, and customer-focused distribution system.

As summarized by the Regulatory Assistance Project (RAP), "[r]egulatory efforts targeting improvements in utility performance began in earnest in the late 1970s and early 1980s. Motivating factors included reliability problems, sizable cost overruns in, and outright cancellation of, nuclear plant construction and, eventually, widespread excess generation capacity."2 However, as more states move forward with decarbonization policies, PIMs

[2] Regulatory Assistance Project, *Improving Utility Performance Incentives in the United States*, October 2023 ("RAP Study"), pp. 9-10

are being used as a mechanism to influence utility behavior towards the advancement of energy policy goals that are not directly aligned with a utility's public service obligations or existing financial incentives.[3]

For example, under standard cost-of-service regulation, utilities have a financial disincentive to invest in energy efficiency and distributed energy resources (DER). PIMs that provide a financial reward to the utility for promoting efficiency and DERs can help address this financial disincentive to better align the utility's business model with a desired policy outcome.[4]

PIMs can also be used to drive utilities to respond to technological changes or to compensate the utility for its perceived risk related to the implementation of new forms of distribution planning such as non-wires alternatives or non-pipes alternatives, where again the utility would tend to have a bias towards capital expenditures.

Q. What characteristics define a well-designed PIM?

A. A well-designed PIM should focus on performance areas where a utility lacks an incentive (or has a disincentive) to achieve a desired outcome.[5]

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[3] RAP Study, p. 11.
[4] Whited, M., Woolf, T., & Napoleon, A. (2015, March 9). *Utility Performance Incentive Mechanisms: A Handbook for Regulators.* Synapse. https://www.synapse-energy.com/synapse-handbook-provides-guidance-designing-implementing-utility-performance-incentive-mechanisms ("Synapse PIM Handbook") p. 3.
[5] As stated in the Synapse PIM Handbook, a key principle and recommendation for PIMs is to "address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives." *Id.,* p. 4.

Existing incentives can take many forms. For example, a utility may have an incentive to invest in new capital to grow its rate base, avoid a penalty, meet an existing regulatory standard, or achieve internal corporate and shareholder goals. To protect ratepayers from unnecessary incentive payments, it is critical that a PIM does not reward the utility for an outcome it already has an incentive to achieve.

A second key characteristic is that a PIM should be based on historical baseline data upon which the regulator deems an improvement is necessary or desirable.[6] Baseline data is important to avoid rewarding a utility for achieving increased performance where there is no demonstrated need and for measuring whether targets the utility set are reasonable and ambitious relative to historical data. In addition, if a utility is already performing well in an area, it may not be in the best interest of ratepayers to incentivize the utility to achieve even higher performance levels. For example, at a certain level, investments to achieve incremental improvements to reliability may have diminishing returns and therefore would not warrant the increased cost to ratepayers. The optimal level of performance should correlate to where

[6] RAP Study, pp. iii; 39.

the marginal benefits from improved performance are equal to the marginal costs of providing that increased level of performance.[7]

B. Regulatory Context

Q. Are the Maryland utilities permitted to propose PIMs within an MYP?

A. Yes. In Order No. 89638, the Commission ruled that utilities may include proposals for PIMs as part of a rate case.[8] In accordance with that Order, utilities are permitted to propose—in a traditional base rate case or an MYP—a PIM "that supports any recognized Maryland policy goal (including but not exclusively ratepayer benefits) beyond historical baseline standards."[9]

Q. May other parties to a rate case propose a PIM?

A. No. Within the same Order, the Commission ruled that only the utility filing a rate case may propose a PIM.[10] However, parties to the rate case may propose modifications to a utility's proposed PIM.[11]

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[7] Whited, M., Woolf, T., Napoleon, A. 2015. *Utility Performance Incentive Mechanisms: A Handbook for Regulators*. Prepared by Synapse Energy Economics, Inc. for the Western Interstate Energy Board. Pages 34-35.
[8] Md. Pub. Serv. Comm'n., *Order Approving Performance Incentive Mechanisms* at 12, Case No. 9618/PC51 (Ord. No. 89638) (Sep. 29, 2020).
[9] *Id*. at 13.
[10] *Id*. at 12.
[11] *Id*. at 12.

Q. Did the Commission provide a set of criteria for evaluating a proposed PIM?

A. Yes. In Order No. 89638, the Commission provided requirements for any utility proposing a PIM.[12] Specifically, a PIM proposal must:

1. Be tethered to a recognized State policy;
2. Accelerate the policy goal beyond the utility's current capabilities;
3. Show measurable benefits to ratepayers; and,
4. Contain metrics which show baseline data over a specific timeframe.[13]

The Commission also found "that any proposed award/penalty structure for a PIM should incentivize utilities to stretch beyond their current capabilities to achieve measurable results."[14] Finally, the Commission stated that any proposed metrics "should be clear and well-defined, unique for each utility, designed so they are not easily met, and benefit ratepayers."[15]

C. Pepco's Proposal

Q. Does Pepco propose PIMs as part of its MYP application?

A. Yes. Pepco has proposed three PIMs in its application: a reliability PIM related to reducing the number of customers who experience four or more

[12] *Id*. at 16.
[13] *Id*.
[14] *Id.* at. 15.
[15] *Id*. at 14.

outages in three consecutive years, a PIM related to reducing the Company's greenhouse gas emissions, and an incentive to remove equipment that contain PCBs.

Q. What is Pepco's rationale for including PIMs in the MYP?

A. The Company states it is proposing PIMs in accordance with Commission Order No. 89638 "to advance State policy goals, accelerate Pepco's current capabilities to meet the three metrics, show measurable benefits to customers, and contain trackable data over the MYP period."[16]

Q. Please describe Pepco's proposed PIM structure.

A. The Company proposes a symmetrical PIM for each of the three metrics. The Company will receive a financial award if it exceeds its proposed annual performance target for a metric or will be assessed a penalty should its performance fall below a satisfactory level, which Pepco defines as the low end of its proposed satisfactory performance range.[17] For each metric, the Company also includes a deadband, or a satisfactory performance range, where no reward or penalty occurs.[18]

The Company states that any resulting reward or penalty will be reflected as basis points that will either be added to, or subtracted from, the Company's

[16] Direct Testimony of Amber Young at 72:3-6.
[17] Direct Testimony of Robert Leming at 67:11-16.
[18] *Id*. at 67:16-18.

return on equity (ROE) as approved by the Commission in this proceeding.[19] Table 1 below, details the proposed basis points (bps) for each performance metric as included in the Direct Testimony of witness Leming.

Table 1. Pepco Proposed PIM Rewards/Penalties for the MYP period

	MYP Rate Year 1	MYP Rate Year 2	MYP Rate Year 3	MYP Rate Year 3 Extension
GHG Emissions Reductions	+/- 10 bps	+/- 10 bps	+/- 10 bps	+/- 10 bps
CEMI-4R3	+/- 10 bps	+/- 10 bps	+/- 10 bps	+/- 10 bps
Removal of PCB-Containing Equipment	+/- 5 bps	+/- 5 bps	+/- 5 bps	N/A
Subtotal - PIM Performance Adjustment, Pre-Cap (in ROE bps)	+/- 25 bps	+/- 25 bps	+/- 25 bps	+/- 20 bps
Capped Total in ROE bps	**+/- 20 bps**	**+/- 20 bps**	**+/- 20 bps**	**+/- 20 bps**
Total Operating Income Impact *	+/- $1.83M	+/- $1.96M	+/- $2.07M	+/- $2.16M
Total Revenue Requirement Impact, Combined*	**+/- $2.6M**	**+/- $2.79M**	**+/- $2.94M**	**+/- $3.07M**

* - Operating Income and Revenue Requirement Impact calculated using Pepco's proposed rate base and capital structure.

Source: Leming Direct Testimony, Table 5.

As shown in Table 1, the rewards and penalties across the three metrics will be added together to calculate the overall Performance Adjustment for the associated year in the MYP. The Company also proposes a cap of 20 basis points upwards or downwards.[20] The Company calculates that 20 basis points would be worth approximately $2.6 to $3.1 million in additional revenue requirement.[21] Using these values, I calculated the estimated values for each performance metric, which are shown in Table 2 below.

[19] *Id*. at 69:4-6.
[20] *Id*. at 68:15-16.
[21] *Id*. at 68:16-69:1-2.

Table 2. Pepco Proposed PIM Rewards/Penalties ($ Millions)

	MYP Rate Year 1	MYP Rate Year 2	MYP Rate Year 3	MYP Rate Year 3 Extension
GHG	+/- 1.3M	+/- 1.4M	+/- 1.47M	+/- 1.54M
CEMI4-R3	+/- 1.3M	+/- 1.4M	+/- 1.47M	+/- 1.54M
PCB	+/- 0.78M	+/- 0.84M	+/- 0.88M	N/A
Total	**+/- 3.38M**	**+/- 3.63M**	**+/- 3.82M**	**+/- 3.07M**
Cap	**+/- $2.6M**	**+/- $2.79M**	**+/- $2.94M**	**+/- $3.07M**

Source: Calculated from Leming Ex. RTL-9.

The Company indicates that the revenue impacts resulting from PIM adjustments to the ROE will be reconciled with customers through the MYP Adjustment Rider proposed in this proceeding.[22]

Q. How will the Company's Annual PIM performance be evaluated?

A. The Company indicates it will file its annual PIM results as part of its MYP Annual Informational Filing.[23] This will include a calculation of the PIM revenue requirement based on the overall performance of the three performance metrics. The Company indicates it will submit the Annual Informational Filing to the Commission within 90 days following the end of each year of the MYP and that the filing will be subject to a 60-day discovery period.[24]

Q. Does the Company provide an example of what information it will include in the Annual Informational Filing related to PIM performance?

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[22] *Id*. at 73:5-7.
[23] *Id.* at 72:18-21.
[24] *Id*. at 72:19-21-73:2-3.

A. Yes. Witness Leming provides an example of the PIM revenue requirement adjustment that Pepco plans to attach to the Annual Informational filing as Schedule RTL-9.[25] He describes two attachments that demonstrate the total PIM reward or penalty for a given MYP year and calculate the revenue requirements based on PIM performance for each line of business to adjust the ROE in a given MYP year.[26]

III. Pepco's Proposed PIMs Should be Rejected

A. Pepco has Incentive to Spend on Capital Projects Without PIMs

Q. Does the Company have an existing financial incentive to achieve many of its proposed performance metrics?

A. Yes, I believe that Pepco has an existing incentive to achieve many of its proposed performance metrics due to its ability to earn a return for shareholders on the capital expenditures underlying much of the PIM-related work.

Q. Please explain why returns on capital expenditures are a financial incentive for utilities.

A. First, rate-of-return incentives are a type of performance incentive used to encourage utilities to invest in energy efficiency or other distributed energy resource (DER) programs. This type of incentive allows utilities to earn a rate of return on energy efficiency or DER spending, comparable to what

[25] *Id.* at Schedule (RTL)-9, Attachment 1, page 1 of 1.
[26] *Id.*

they receive for traditional capital investments. As noted by the U.S. Environmental Protection Agency (EPA), shareholder performance incentives can include providing utilities the ability to earn a rate of return on specific operating expenses such as energy efficiency or other DER programs in recognition for the multiple benefits they can provide.[27] The American Council for an Energy-Efficient Economy (ACEEE) also summarizes this type of performance incentives, stating:

> "[t]his type of incentive is important for investor-owned utilities because of their financial responsibility towards their shareholders, and because of the traditional bias towards rewarding supply-side investments with a higher return. This higher return leads to higher earnings for shareholders compared with an energy efficiency program, even though the latter delivers incremental resource requirements at lower cost."[28]

Furthermore, regulated utilities have an inherent incentive to favor capital expenditures over operating expenses in order to increase return to investors. Indeed, this can be seen in Pepco's parent company's Winter 2023 Investor

[27] U.S. Environmental Protection Agency, 2022, *State Energy and Environmental Guide to Action: Electric Utility Regulatory Frameworks and Financial Incentives*, at 11.

[28] American Council for an Energy-Efficient Economy (ACEEE), Performance Incentives Toolkit, May 14, 2012. Available at: https://www.aceee.org/toolkit/2012/05/performance-incentives#:~:text=Rate%20of%20return%20incentives%20allow,return%20on%20supply%2Dside%20investments.

Meetings slide deck, which touts to utility investors a "strong growth outlook" based on "~$31.3B of T&D capital from 2023-2026," "reinvestment of free cash to fund utility capital programs," and "investment growth" which focuses on "higher rate base growth" for the Company of 7.9 percent from 2022-2026.[29] Exelon's investors are aware and keenly focused on Exelon's focus on ratebase growth which is achieved through capital expenditure.

B. Pepco's Reliability PIM is Easily Achieved, Sufficiently Incentivized, not Cost-effective for Residential Customers, and Mandated under Compliance Obligations

Q. What PIM does Pepco propose related to reliability?

The company proposes a CEMI-4R3 performance metric which focuses on reducing the number of customers experiencing consistent, below-average reliability defined as "customers experiencing four or more interruptions each calendar year for three consecutive years."[30]

Specifically, Pepco proposes to reduce the number of customers who experienced four or more sustained interruptions to no more than 117 customers.[31] Table 3 provides an overview of Pepco's proposed performance levels for this metric. While the Company does not provide a budget estimate for the 2024-2027 period, the budget estimate for 2023 was

[29] Attachment B, Exelon Winter 2023 Investor Meetings at slides 11, 15, and 33 (emphasis added).
[30] Direct Testimony of Amber Young at 74.
[31] *Id*. at 76:2-3.

$2.3 million for the same type of projects.[32] Funding related to these reliability projects will harden and reconductor circuits, and install sectionalizing equipment "including reclosers, fuses, trip savers, smart fuses, and motor operated switchgears."[33] However, Pepco has not provided a precise budget estimate or scope for these projects.

Pepco proposes plus or minus 10 basis points for the reward or penalty for this performance metric, based on the following performance levels.

Table 3: Pepco Proposed PIM for CEMI-4R3

Performance Level *(customers experiencing four or more interruptions each calendar year for three consecutive years)*	**2024**	**2025**	**2026**	**2027**
Reward *(+10 basis points ROE)*	117 or less	117 or less	117 or less	117 or less
Satisfactory *(no reward/penalty)*	117-195	117-195	117-195	117-195
Penalty *(-10 basis points ROE)*	>195	>195	>195	>195

Source: Young at 76

Q. How did Pepco determine these performance levels?

A. The Company states that it aligned its methodology to the one proposed by BGE in its MYP 2.[34] For the lower and upper band performance targets, BGE's proposal indicated a ratio of 15 percent and 25 percent of customers

[32] *Id.* at 77:8; *see also* OPC DR 9-13(f).
[33] *Id.* at 79:2-3.
[34] *Id.* at 76:10. Case No. 9692.

that experience four or more outages over three years to "candidates,"or customers that experience four or more outages over two years. . These percentages (15 percent and 25 percent) were multiplied by Pepco's average number of "candidates" from 2018-2022, 780 customers, to determine the performance bands.[35]

Q. What analyses does Pepco present to support its PIM?

A. Pepco presents some data on reliability and the number of *candidates* experiencing two consecutive years of four or more interruptions, though this data is not directly related to the performance needed to achieve the target, which relates to the number of customers who experience four or more interruptions over three consecutive years. Pepco's primary support comes in the form of a benefit-cost analysis, in which the Company finds the CEMI-4R3 proposal will provide $4.1 million in benefits compared to an estimate of $2.3 million in expenditures (from 2023), which equates to a benefit-cost ratio of 1.8.[36]

Q. What are your concerns about Pepco's reliability PIM?

A. I have several concerns:

1. The PIM does not accelerate performance on reliability metrics beyond Pepco's current capabilities This is directly contrary to the Commission's Order No. 89638.

[35] From 2018-2022 there were an average of 780 CEMI-4R3 candidates. 15% * 780 = 117; 25% * 780 = 195. *Id. at 76-77.*
[36] *Id.* at 77:12.

2. The Company should not receive additional financial incentive for performing core public service obligations including reliable electric service. The Company is already required under § 7-213 of the Maryland Public Utility Article to provide "its customers with high levels of service quality and reliability in a cost-effective manner […] each electric company shall be held accountable if it fails to deliver reliable service according to those standards."[37] Furthermore, Code of Maryland Regulations (COMAR) Chapter 20.50.12 requires specific reliability standards. A performance metric should support an objective that is not already addressed through existing regulatory measures.[38]

3. The Company already has sufficient incentive to perform the proposed work since they would primarily be achieved through additional capital expenditures on which Pepco can earn a return.

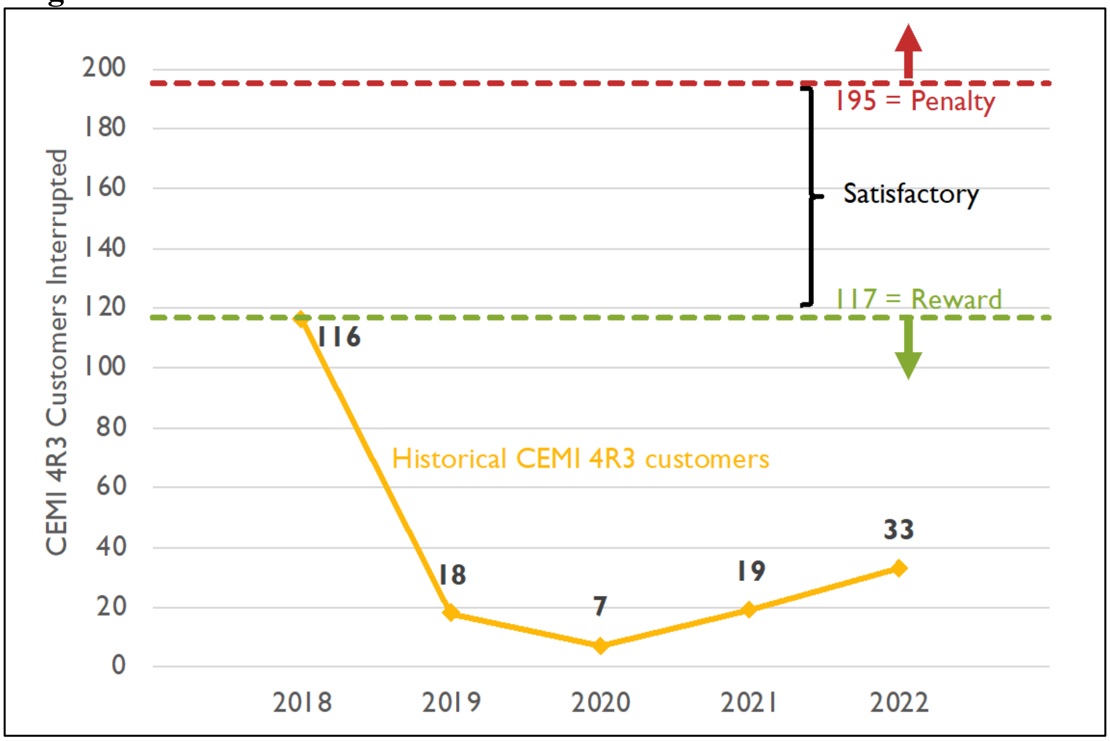
4. The Company's benefit-cost analysis does not examine the impact of the PIM payment on cost-effectiveness, and the utility ignores that the program is not cost-effective for residential ratepayers.

Q. Why do you state that Pepco's reliability PIM does not accelerate performance beyond existing capabilities?

A. The figure below shows the Company's historical performance compared with the proposed PIM targets.

[37] Md. Ann. Code, Pub. Utilities Art. § 7-213.
[38] Order No. 89226 at 58.

Figure 1. Historical CEMI-4R3 customers compared with proposed PIM targets[39]



The data show that in each year of recorded data the Company would have met its performance goal, which it previously achieved without any performance incentive. Under Pepco's proposal, customers would pay an additional $1.3 million per year for the achievement of extremely sub-par performance as compared with recent history in which the number of CEMI-4R3 customers has already significantly exceeded the proposed target level. For example, the number of CEMI-4R3 customers could *increase* by 350 percent over 2022 and the Company would receive its suggested PIM reward. I also note that it is inappropriate that Pepco did not present this

[39] Historical data from OPC DR 9-11.

information in its testimony – it was ascertained only through discovery and was not available in the Company's testimony or application. This presentation makes it impossible for the Commission to easily compare historical performance with the PIM targets.

Q. Is the reliability PIM appropriate based on current regulatory requirements?

A. No it is not. The Commission stated in Order No. 89226 that the PIMs working group should work towards "identifying goals and outcomes … that align utility performance with State policy objectives that are not already addressed through existing regulatory measures."[40] However, the Company is already required under § 7-213 of the Maryland Public Utility Article to provide "its customers with high levels of service quality and reliability in a cost-effective manner […] each electric company shall be held accountable if it fails to deliver reliable service according to those standards."[41]

Q. Is Pepco required to meet a specific level of performance for the CEMI-4R3 metric?

A. A. Not directly. However, COMAR 20.50.12.03 states "(4) No feeder shall appear in a utility's list of poorest performing feeders during three consecutive 12-month reporting periods, unless the utility has undertaken reasonable remediation measures to improve the performance of the feeder."

[40] Emphasis added. Order No. 89226 at 58.
[41] Md. Ann. Code, Pub. Utilities Art. § 7-213.

This requirement is likely to interact with the proposed PIM. Further, while COMAR 20.50.12 does include specific performance targets for other metrics (such as SAIDI and SAIFI) that electric companies must meet, and the reliability-related investments that Pepco makes in order to achieve the mandated performance targets is likely reduce the number of customers experiencing four or more sustained outages over a given time period.

Q. Please explain why the PIM is unnecessary to incentivize this reliability work.

A. The reliability work at question is typical utility work that is already sufficiently incentivized as it is comprised entirely of capital expenditures as I explained above in Section A).[42] Pepco admits that it has no financial dis-incentive to accomplish this work,[43] and further that it would likely accomplish the work even if the PIM is not adopted: "If the PIM is not approved, the Company's existing CEMI program would still address customers in this population, per Exelon-wide best practice."[44]

Q. Does the Company conduct a benefit-cost analysis for its reliability PIM?

A. The Company conducts a benefit-cost analysis (BCA) assuming its 2023 CEMI budget of $2.3 million, finding, on average, that the program results

[42] OPC DR 9-13(g).
[43] OPC DR 9-17.
[44] OPC DR 9-18.

in benefits that are 180 percent greater than costs,[45] and therefore has a benefit-to-cost ratio of 1.8. A benefit-to-cost ratio of 1 indicates a proposal has costs equal to benefits; below 1 means benefits are less than costs. The results of this analyses appear to be provided as justification for the proposed PIM, as well as the underlying expenditures.

Q. Please explain your concerns with the Company's benefit-cost analysis.

A. First, the BCA ignores the impact of the PIM on the benefit-cost ratio (BCR), as the PIM payment is not included in the analysis.[46] This is incorrect, because the PIM is a cost that is incurred by ratepayers and the BCA is presented in support of the PIM. As stated in the National Standard Practice Manual (NSPM) "the parties experiencing the costs (all customers) and the parties experiencing the benefits (utilities or program administrators) are within the utility system and therefore should be included in all cost-effectiveness tests."[47]

Including the PIM payment reduces the overall BCR from 1.8 to 1.1, making it barely cost-effective.[48] Third, the Company ignores the implications of its

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[45] Direct Testimony of Amber Young at 77:8-12.
[46] OPC DR 9-15.
[47] National Energy Screening Project, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (NSPM for DERs), Aug. 2020, https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-04-2020_Final.pdf.
[48] The average PIM payment, calculated from workpapers RTL-9, is $1.4 million over the MRP period. Adding this to the assumed cost of $2.3 million and comparing to the Company's annual benefit of $4.1 million equates to a BCR of 1.1.

analysis for residential customers. Even before the PIM, the program is not cost-effective for residential ratepayers, and after the PIM is incorporated the program is even less cost-effective.

Q. Is the CEMI-4R3 program cost-effective for residential ratepayers?

A. No. My analysis shows that the work Pepco proposes to perform for this program will not be cost-effective for ratepayers. I begin by assuming that 60 percent of costs are allocated to residential ratepayers, based on Schedule LCS-5, which shows cost allocation percentages by class.[49] I then use the Company's benefit calculations by class presented in testimony[50] and compare these with costs to the residential class using Pepco's 2023 spending of $2,284,654 (since this is the basis of the BCA). I find that this results in a 0.13 benefit-to-cost ratio for residential ratepayers without the PIM, and a 0.08 benefit-to-cost ratio for residential ratepayers when the PIM is included, a 38 percent reduction.[51]

Q. What do you conclude based on these results?

A. In addition to the other flaws discussed above, adoption of the CEMI-4R3 PIM will significantly diminish the benefits of the program. While the

[49] Schedule LCS-5, Allocation Development Tables, page 8 line 11. Rounded up from 58%.
[50] Direct Testimony of Amber Young at 78, Table 11A.
[51] This assumes the same allocation of PIM costs as above. The annual benefit for residential customers is $178,084 (Young at 78, Table 11A) and this is compared with costs of the program ($2.3 million) multiplied by 60 percent. I multiply the average PIM from 2024-2027 of $1.4 million by this same percentage, 60 percent, and add this to the cost, to derive the BCR with the PIM.

program is not cost-effective for residential ratepayers without the PIM as the results of the BCA show a benefit-to-cost ratio that is less than 1 because reliability benefits are less than costs imposed on customers cost-effectiveness is significantly worsened when PIM costs are added to the analysis.

Q. What do you recommend?

A. The CEMI-4R3 reliability PIM should be rejected. It is easily achieved, sufficiently incentivized, not cost-effective for residential customers, and directly related to existing regulatory requirements.

C. Pepco's GHG PIM is Unsupported, Easily Achievable, and Adequately Incentivized through Capital Expenditures and Internal Company GHG Reduction Targets

Q. Please summarize Pepco's proposed GHG Emissions Reduction performance metric.

A. The company proposes a GHG Emissions Reduction performance metric ("GHG performance metric") to support Maryland's 2045 net-zero GHG emissions target.[52] This performance metric is made up of three initiatives: Fleet Electrification, Sulfur Hexafluoride (SF6) Emission Reduction Program, and Building Energy Usage at Company facilities.

[52] Direct Testimony of Amber Young at 79.

Q Please describe these three GHG emissions reductions programs.

A The fleet electrification program seeks to replace existing internal combustion engine vehicles with electric vehicles.[53] SF6 emissions reductions will be achieved by prioritizing repairs of leaking equipment and "by exploring alternative insulating sources for equipment installation."[54] Finally, the Building Energy Usage program will install solar and use "cleaner substation infrastructure at Pepco MD substations."[55]

Q What are the proposed performance levels for the GHG PIM?

A The Company's proposed performance levels for the GHG performance metric, shown in Table 4 below, represent the sum of the Company's annual GHG emissions, in terms of tons of carbon dioxide equivalent (CO2e), resulting from this portfolio of initiatives. Pepco proposes plus or minus 10 basis points for the reward and penalty for this performance metric.

Table 4. Pepco's GHG PIM Proposal[56]

Performance Level	2024	2025	2026	2027
Reward	Less than 22,731	Less than 22,711	Less than 22,691	Less than 22,672
Satisfactory	22,732-35,037	22,712-35,037	22,692-35,037	22,673-35,037
Penalty	Greater than 35,037	Greater than 35,037	Greater than 35,037	Greater than 35,037

[53] *Id.* at 79:15-17.
[54] *Id.* at 80:15-18.
[55] *Id.* at 81:6-9.
[56] OPC DR 24-7(a).

Q. Do you have concerns with Pepco's GHG PIM proposal.

A. Yes. I have four primary concerns:

1. The proposal is ill-defined, unsupported, and lacks sufficient detail. The Company presents no BCA or other analysis to demonstrate whether its proposals are cost-effective and in the ratepayer interest, or whether there are more cost-effective ways to achieve emissions reductions than those proposed.

2. The reward targets are too easily achievable, rather than the stretch goals required by Order No. 89638. In fact Pepo has already achieved these GHG targets every year since 2017. Further, the penalty thresholds are not meaningful.

3. The Company has sufficient incentive to pursue these projects. The programs are primarily capital expenditures, and the Company has public goals related to GHG emissions it has stated it will pursue, presumably without a PIM.

4. Pepco's parent company, Exelon, has GHG emissions reductions goals. It is inappropriate for ratepayers to fund "incentives" for the Company's own effort.

Q. Is the utility's proposal for GHG programs and related PIMs well supported?

A. No. The utility's testimony provides a dearth of information. It lacks basic relevant historical information on GHG emissions, estimated costs of programs related to the PIMs, what the proposed targets for each PIM are, and why certain targets were chosen. Information regarding historical GHG emissions after 2015 and fleet electrification cost data was obtained through discovery,[57] but certain basic elements, such as the proposed and historical

[57] OPC DR 9-22 (GHG emissions); OPC DR 9-24 (fleet electrification).

costs for SF6 breaker repair and replacement[58] and costs for the building energy usage program[59] are unavailable. Further, the Company presents no cost-effectiveness analysis to determine whether the underlying programs are: a) in the ratepayer/societal interest or b) whether they are the least expensive way of achieving GHG reductions. The Commission should not approve a PIM for a program without knowing what it will cost ratepayers or whether the underlying activity is in the ratepayer interest.

Q. How could a GHG reduction program not be beneficial for society?

A These programs will entail real costs that the Company will seek from ratepayers at a later date. When identifying investments to reduce GHG emissions, it is common to consider a marginal abatement cost (MAC) curve to compare the cost and emissions impact of different technologies. The most common example is the McKinsey cost curve, which compares the cost of GHG abatement across a variety of technologies.[60] Without a comparison of the cost of different available GHG reduction approaches, it is not possible to assess whether an alternative program could have provided more GHG emissions reductions at a lower cost. Without this basic determination, these programs should not be approved.

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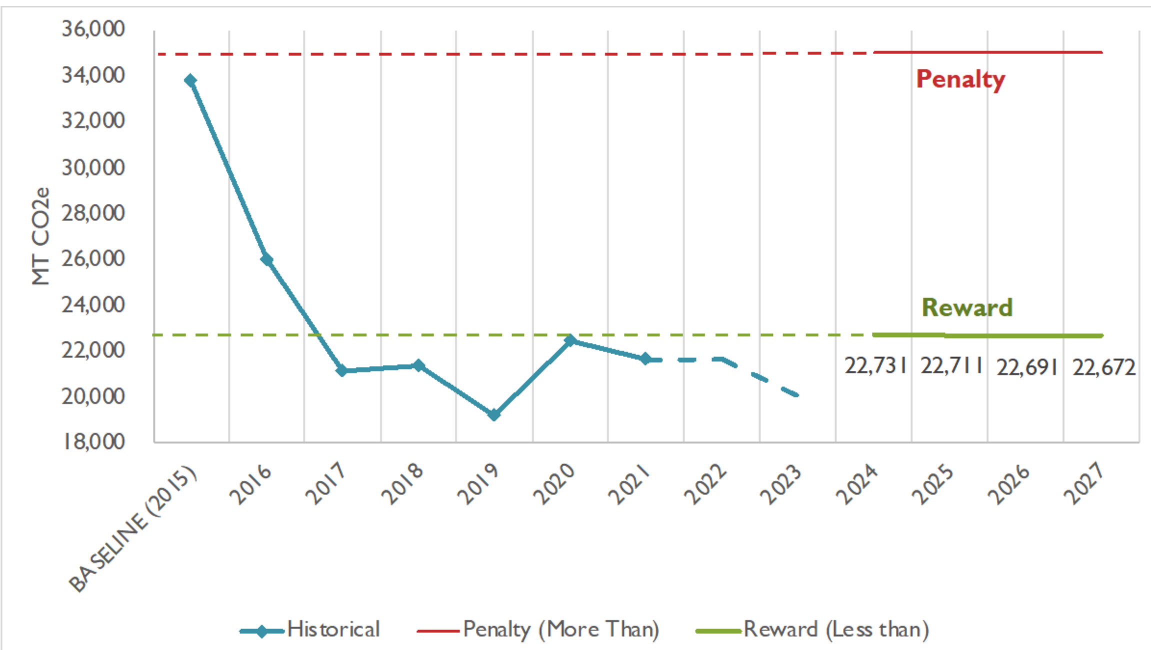
[58] OPC DR 24-3.
[59] OPC DR 9-29(a).
[60] McKinsey Website: https://www.mckinsey.com/capabilities/sustainability/our-insights/a-cost-curve-for-greenhouse-gas-reduction.

Q. Why do you believe the Company's PIM targets are easily achievable?

A. The Company uses a 2015 baseline for its emissions reductions, even though emissions have significantly decreased since this time. As shown in the figure below, Pepco's proposal is for ratepayers to pay shareholders excess returns for goals the Company has *already achieved* in each year from 2017-2021.

Figure 2. Pepco proposed GHG PIM penalty and reward based on historical data[61]



As is seen clearly in the chart above, the penalty threshold is virtually meaningless, in contrast with the reward threshold which has already been met. Essentially, therefore, Pepco seeks to reward itself for average or sub-par performance compared to what the Company has already achieved with

[61] The dashed line as part of "historical" data indicate projections from the Company. *See* OPC DR 24-2(a) attachment (historical emissions data); OPC DR 24-7(a) for penalty/reward.

no PIM in place (shown above), with no real threat of penalties for poor performance, on top of returns it will accrue from related capital expenditures.

Q Does the Company have sufficient incentive to pursue these projects?

A Overall, yes. First, expenditures related to vehicle fleet replacement are ratepayer-funded capital expenditures.[62] Second, SF6 breaker removal appears to consist primarily of capital expenditures, though some repairs are considered O&M.The Company was unable to provide any historic or prospective analysis of the specific cost breakdown between capital and O&M expenditures for SF6 breaker projects. However, the Company admits it has no financial disincentive to perform this work.[63] Third, it appears costs for the Building Energy Usage program will be funded by shareholders, though Pepco's discovery response is unclear and the Company does not know the costs or specifics of its proposed program.[64]

With the exception of the Building Energy Usage program, if it is indeed shareholder funded, the Company has sufficient financial incentive to pursue these programs.

[62] Staff DR 5-17.1.
[63] OPC DR 9-26; OPC DR 24-3.
[64] OPC DR 9-24.

D. Pepco's GHG PIM to Remove Equipment with PCBs is Easily Achievable, Adequately Incentivized, and Disproportionate to the Level of Expenditure

Q. Please describe Pepco's PCB PIM proposal.

A. The primary purpose of the PCB performance metric is to accelerate the replacement of PCB-containing equipment from Pepco's distribution transformers. The Company indicates that the primary benefit of this program is the decreased likelihood of spills and potential environmental contamination from PCBs.[65]

The Company will measure the performance of this metric by tracking the replacement of PCB-containing transformers with new transformers.[66] Table 5 shows the Company's planned removal targets. The Company proposes plus or minus 5 basis points for the reward and penalty for this performance metric. Because the Company's plan expects the removal of all remaining 46 pieces of equipment by 2026, there is no proposed ROE reward or penalty in 2027.[67]

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[65] Direct Testimony of Amber Young at 83:14-15.
[66] *Id.* at 84:4-5; 85, Table 13.
[67] *Id.* at 84:7.

Table 5. Pepco Proposed PIM for PCB Equipment Removal

Performance Level *(number of equipment removed)*	**2024**	**2025**	**2026**	**2027**
Reward *(+5 basis points ROE)*	20	15	11	None
Satisfactory *(no reward/penalty)*	1-19	1-14	1-10	None
Penalty *(-5 basis points ROE)*	0	0	0	None

Q. Please summarize your concerns with the Company's proposal.

A. I have three primary criticisms:

1. The PIM is easily achievable, contrary to Order No. 89638, and seeks to unduly enrich shareholders for work that ratepayer funding is already intended to accomplish.

2. There is no financial dis-incentive, but rather a financial incentive, for the Company to accomplish this work, as utility shareholders receive returns for the capital expenditures to replace transformers.

3. Not only is the PIM unnecessary, the level of return proposed is disproportionate to the level of expenditure.

Overall, I find that the proposal is flawed, unreasonable, and unnecessary.

Q. Why are the targets easily achievable?

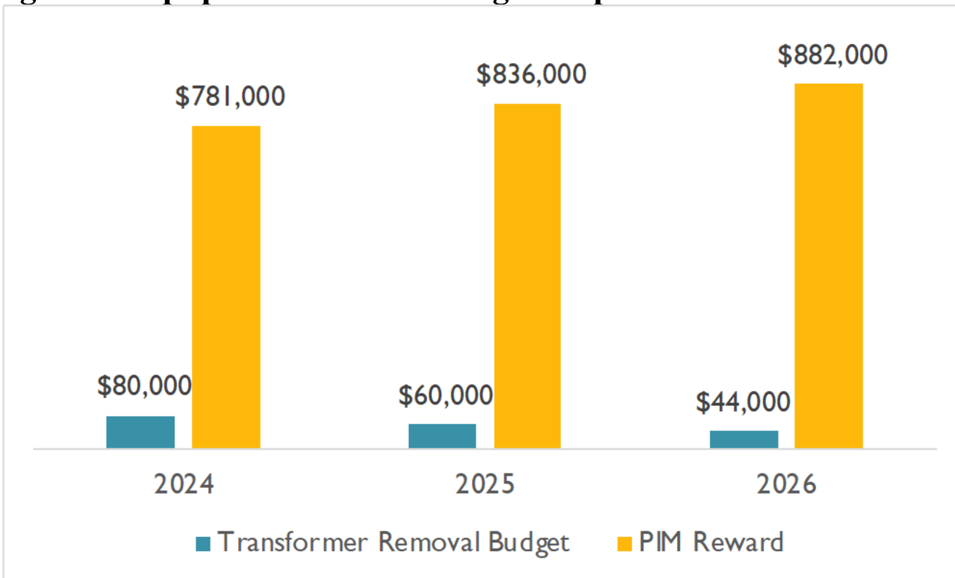
A. First, in order to avoid a penalty, the Company needs to remove just *one* transformer in each year. Second, as seen above, to achieve the PIM reward the Company would need to remove just 20, 15, and 11 transformers from 2024-2026, respectively. In 2024, the highest number of removals, this removal work would take around 240 labor hours, split between two people, according to the Company.[68] Put another way, it would take just 15 days each for 2 linesman out of the entire year to accomplish this work, and much less than this in subsequent years – yet the same amount of return would be rewarded. This is not "beyond the utility's current capabilities," contrary to Commission guidance,[69] nor is the PIM symmetrical between penalty and reward.

Q. Is a PIM necessary for Pepco to accomplish this work?

No. First, the work is ratepayer funded and is a capital expenditure, wherein the Company has sufficient incentive to add to its rate base. There is certainly no financial disincentive for the Company to accomplish this work. Further, not only is the financial return not necessary, it is exorbitant when compared with the level of expenditure to do the removal work. This is shown in Figure 3 below.

[68] OPC DR 9-41. "On average, it takes two linepersons, approximately 6 hours on average to remove a PCB overhead distribution transformer."
[69] Order No. 89638, p. 15.

Figure 3. Equipment removal budget vs. potential PIM reward



Source: Budget figures from Young, p. 85, Table 13; PIM reward calculated from RTL-9.

In 2026, Pepco would be awarded a 1,905 percent return on its $44,000 of expenditures to remove PCB transformers. This represents an unnecessary and excessive windfall for Pepco's shareholders if adopted.

Q. What is your recommendation?

A. Either the PIM should be rejected in its entirety, or, alternatively, if the budget to remove PCB transformers is approved, it should be penalty only based on the number of transformers sought to be removed under the reward. If the Commission wishes to ensure that Pepco accomplish this work, it need not unduly harm ratepayers with an unnecessary relatively large payment to the Company's shareholders.

IV. Other Parties Should be Permitted to Propose PIMs in Litigated Dockets

Q. Are parties, including OPC, allowed to propose PIMs?

A. In Order No. 89638, the Commission found that "for administrative efficiency, only the utility filing a rate case may propose a PIM."[70]

Q. Based on your review of the utility's PIMs, is the Commission's ruling in Order No. 89638 in the ratepayer interest?

A. No. The PIM proposals presented by Pepco in this proceeding demonstrate a clear conflict of interest, in which the Company wishes to accept little to no risk while having the opportunity to reap excess profits for its shareholders. PIMs should be designed to be in the public interest, not the interest of shareholders.

Q. How do you recommend the Commission move forward with PIM proposals?

A. The Commission should revise its decision from Order No. 89638 and allow other parties to propose PIMs in litigated dockets.[71] Other parties are in a better position to create PIMs in the public interest than the utilities. Litigated proceedings provide a process for parties to obtain data through discovery, and, where appropriate, propose a PIM.

Q. Does this conclude your testimony?

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[70] Order No. 89638, p .12

[71] As noted above, this recommendation has just been adopted in Order No. 90948, Case No. 9692 at 209-210 (Dec. 14, 2023). Again, I am including this recommendation to complete the record in this case.

A. Yes, it does.

Eric Borden, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7042
eborden@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA*. Principal Associate,* May 2022 – Present

- Sponsors expert testimony and performs analyses related to utility electric vehicle incentives and policy, wildfire mitigation strategies and costs, risk modeling, rate design, cost allocation, and revenue requirement issues in General Rate Cases and Multi-year Rate Plans.
- Conducts research and analysis related to the cost-effectiveness of distributed energy resources and Integrated Resource Plans.
- Examines utility performance incentives and provides expertise on ratemaking issues.

The Utility Reform Network (TURN), San Francisco, CA*, Energy Policy Expert,* February 2015 - May 2022

- Prepared testimony, conducted analyses, drafted comments, and represented TURN in various proceedings at the California Public Utilities Commission (CPUC) related to general rate cases, wildfire-related safety applications, electric vehicle charging infrastructure, utility procurement, rate design, and demand response.

4 Thought Energy LLC, Chicago, IL. *Senior Energy Analyst*, June 2013 – January 2015

- Created financial models to forecast profits of potential site installations
- Researched state and regional public policy frameworks governing CHP
- Conducted analyses over electricity and natural gas price trends
- Developed presentations and marketing materials for investor meetings

International Renewable Energy Agency (IRENA) Bonn, Germany. *Consultant,* February 2014 – October 2014

- Hired to write a report on worldwide electricity sector battery storage, including primary applications for renewable energy integration, market developments, trends, and case studies
- Conduct research, review literature, interview key industry players, develop case study material
- Travel to Bonn, company sites, and research facilities
- Written report will be sent to policymakers in 167 IRENA member countries

Alexander von Humboldt Foundation (hosted by DIW Berlin), Berlin, Germany. *German Chancellor Fellow*, July 2012 – November 2013

- Research Project: "Energy Storage Technology and the Large-Scale Integration of Renewable Energy"
- Investigated the role of energy storage in Germany for renewable integration through literature review, interviews with German energy experts, and analysis comparing public policy support in Germany and the U.S. for storage technologies
- Invited to hold a presentation at the International Renewable Energy Storage Conference and Exhibition (IRES 2013)
- Discussions with German businesses and governmental ministries; special visit to European Union and NATO headquarters in Brussels
- Attended energy conferences and workshops in Berlin

The Kenrich Group, LLC, Chicago, IL. *Senior Consultant*, June 2008 – July 2009

- Consulted for multiple energy utilities in legal disputes with the Department of Energy (DOE)
- Performed detailed research and quantitative/qualitative analysis to analyze financial impact related to construction of coal-fired power plants, liquid natural gas facilities, and other types of construction
- Contributed to final reports and presentations submitted in arbitration, settlement, or court of law presenting KRG's expert opinion

Charles River Associates, Chicago, IL. *Associate - Intellectual Property*, July 2006 – May 2008

- Developed complex financial models including discounted cash flow, lost profit, and regression analyses to support expert reports within the context of intellectual property and financial litigation in multiple industries
- Created valuation models and supporting materials to value business entities
- Contributed to final reports and presentations submitted in arbitration, settlement, or court of law presenting CRA's expert opinion

EDUCATION

University of Texas, LBJ School of Public Affairs, Austin, Texas

Master of Public Affairs, specialization in Natural Resources and the Environment, 2012

Washington University, St. Louis, MO

B.S.B.A. Finance, Entrepreneurship, 2006

PUBLICATIONS

Borden, E., B. Havumaki, A. Lawton, M. Whited. 2023. *Establishing Income Based Fixed Charged in California.* Synapse Energy Economics for The Utility Reform Network and Natural Resources Defense Council.

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Clean Energy Technology and Public Policy, LBJ Journal of Public Affairs, editor and contributor, 2011.

TESTIMONY

Case No.9692. Direct Testimony of Eric Borden on the matter of the Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of The Office of People's Counsel. June 30, 2023.

NSUARB M10960: Direct Testimony of Eric Borden on the Matter of an Application by Eastward Energy Incorporated for Approval of a Schedule of Rates, Tolls and Charges Pursuant to Section 21 of the Gas Distribution Act. On behalf of the Counsel to Nova Scotic Utility and Review Board. April 12, 2023.

A.22-05-016: Prepared Testimony Addressing San Diego Gas and Electric's Test Year 2024 Wildfire Mitigation Hardening Measures and Related Wildfire Risk Modeling Issues for The Utility Reform Network. March 27, 2023.

A.22-05-015/A.22-05-016: Prepared Testimony of Eric Borden and Courtney Lane Addressing Quantitative Risk Analysis Issues in Sempra's 2024 Test Year General Rate Case for The Utility Reform Network. March 27, 2023.

Public Service Commission of South Carolina (Docket No.2022-254-E): Direct Testimony of Eric Borden regarding the Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges. On behalf of South Carolina Department of Consumer Affairs. December 1, 2022.

State of Illinois, Illinois Commerce Commission (Docket 22-0432/22-0442): Direct Testimony of Eric Borden and Courtney Lane regarding the Petition for Approval of Beneficial Electrification Plan Under the Electric Vehicle Act, 20 ILCS 627/45 And New EV Charging Delivery Classes Under the Public Utilities Act, Article IX. On behalf of The People of the State of Illinois. September 22, 2022.

Public Utilities Commission of Maine (Docket No. 2022-00152): Direct Testimony of Melissa Whited-and Eric Borden regarding Central Maine Power Company's request for rate design increase and changes. On behalf of the Maine Office of the Public Advocate. December 2, 2022.

A.21-06-021: Prepared Testimony Addressing Pacific Gas and Electric's Test Year 2023 General Rate Case – Wildfire Mitigation and New Customer Connections Cost Requests. June 13, 2022.

A.21-09-008: Prepared Testimony Addressing the Reasonableness of Pacific Gas and Electric 2020 Vegetation Management Balancing Account Overspend. May 25. 2022.

A.21-06-022: Prepared Testimony Addressing Pacific Gas and Electric's Framework for Substation Microgrid Solutions. March 30, 2022.

A.21-10-010: Prepared Testimony Addressing Pacific Gas and Electric's Electric Vehicle Charge 2 Proposal. March 2, 2022.

A.20-09-019: Prepared Testimony Addressing Pacific Gas and Electric's Wildfire Mitigation Memorandum Accounts. April 14, 2021.

A.19-08-013: Prepared Testimony Addressing Southern California Edison's Test Year 2021 Track 2 General Rate Case Memorandum Account Request – Wildfire Expenditures. September 4, 2020.

A.20-03-004: Joint Testimony with Eduyng Castano (SCE) Addressing Data Collection and Evaluation of the New Homes Battery Storage Pilot Program. September 1, 2020.

A.19-10-012: Prepared Testimony Addressing San Diego Gas and Electric's Power Your Drive 2 Electric Vehicle Charging Infrastructure Proposal. May 18, 2020.

A.19-08-013: Prepared Testimony Addressing Southern California Edison's General Rate Case Wildfire Management, Wildfire Risk, Vegetation Management, and New Service Connection Policy Issues and Cost Forecasts. May 5, 2020.

A.18-12-009: Prepared Testimony Addressing Pacific Gas and Electric's Enhanced Vegetation Management and System Hardening Wildfire Mitigation Expenditures. July 26, 2019.

A.18-09-002: Direct Testimony Addressing SCE's Grid Safety and Reliability Program Infrastructure Proposal. April 23, 2019.

A.18-06-015: Rebuttal Testimony Addressing SCE's Charge Ready 2 EV Infrastructure Proposal. December 21, 2018.

A.18-06-015: Direct Testimony Addressing SCE's Charge Ready 2 EV Infrastructure Proposal. November 20, 2018.

A.17-12-011: Direct Testimony Regarding Potential Effects of More "Cost Based" TOU Rates and Seasonal Differentiation of Tiered Rates. October 26, 2018.

A.18-02-016 et al.: Prepared Testimony Addressing Issues Pertaining to AB 2868 (Energy Storage). August 10, 2018.

A.17-12-002 et al.: Prepared Testimony Addressing the Proposal of SCE for Energy Storage Procurement. April 9, 2018.

A.17-01-020: Direct Testimony Addressing the Proposal of PG&E for a Fast Charging Infrastructure Program. July 25, 2017.

R.12-06-013: Direct Testimony Evaluating Hardship due to TOU Rates on Vulnerable Populations in Hot climate Zones. April 19, 2017.

A.15-09-001: Direct Testimony Addressing the Proposal of PG&E for Electric Distribution and New Business Expenditures. April 29, 2016.

A.15-02-009: Rebuttal Testimony Regarding PG&E's A.15-02-009 for EV Infrastructure and Education Program. December 21, 2015.

A.15-02-009: Direct Testimony Regarding PG&E's EV Infrastructure and Education Program. November 20, 2015.

A.14-11-003: Direct Testimony Addressing the Treatment of Solar Distributed Generation for Estimating Distribution System Capacity/Expansion Expenditures. May 15, 2015.

A.14-04-014/R.13-11-007: Testimony Regarding SDG&E's Application for Authority to Build Electric Vehicle Charging Infrastructure. April 13, 2015.

Resume updated July 2023

Potomac Electric Power Company's Application for Adjustments to its Retail Rates for the Distribution of Electric Energy

Case No. 9702

Data Responses Referenced in the Direct Testimony of Eric Borden

OPC DR 9-11

OPC DR 9-13

OPC DR 9-15

OPC DR 9-17

OPC DR 9-18

OPC DR 9-22

OPC DR 9-24

OPC DR 9-26

OPC DR 9-29

OPC DR 9-41

OPC DR 24-2

OPC DR 24-3

OPC DR 24-7

Staff DR 5-17

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 11

From 2012-2022, annually, please provide the number of customers who experienced four or more sustained interruptions over three consecutive years. (Please provide in Excel with all supporting assumptions and calculations. If this specific time period is not available please provide all data available on an annual basis for the number of customers who experienced four or more sustained interruptions over three consecutive years.)

RESPONSE:

Below is the requested CEMI4R3 data over an annual period from 2018-2022. No other data prior to this timeframe is available.

YEAR	CEMI 4R3 Customers Interrupted*	CEMI 4R3 Candidates**
2018	116	835
2019	18	679
2020	7	761
2021	19	130
2022	33	1497

*Experienced 4 outages over 3 straight years

**Experienced 4 outages over 2 straight years, going into 3rd year

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 13
Please refer to Witness Young's testimony, page 77, which states "Given a 2023 CEMI budget of $2,284,586, the additional avoided customers interrupted would be forecasted to be 1,983."

(a) Please explain how the 1,983 additional avoided customers was determined and provide all workpapers and assumptions in Excel.

(b) How many of these 1,983 additional customers are CEMI4-3P customers? Please explain and provide all supporting workpapers and calculations in Excel.

(c) Is the $2.3 million "CEMI budget" requested to be recovered from ratepayers? (Please explain and state whether this is described in any other witnesses' testimony.)

(d) If the $2.3 million budget is approved by the Commission but the PIM is denied, will PEPCO not go forward with the projected spending? (Please explain.)

(e) Please provide the expected mix of residential vs. commercial customers for the 1,983 customers.

(f) Please explain what investments are requested for the $2.3 million.

(g) Is the $2.3 million a capital expenditure? (Please explain.)

(h) Please explain and quantify how the 1,983 customers relates to the 117/195 upper and lower bands described in Table 6 on page 76. (Please provide all calculations with assumptions in Excel.)

(i) Please provide the percentage of the $2.3 million in costs that will be allocated to the residential, small C&I, and medium and large C&I classes, respectively, in 2024, 2025, and 2026. (If 2024-2026 data is not available, please provide these percentages for 2022 for similar types of expenditures.)

RESPONSE:

(a) The methodology used in calculating impact to Avoided Customers Interrupted (ACI) requires actual historical reliability for all past candidates. A similar methodology was utilized by Baltimore Gas and Electric. To evaluate the ACI of an individual customer, performance can be inspected in all three years of a tracking period. For example, consider a customer that experienced seven interruptions in 2019, five in 2020, and after being addressed by a CEMI project, only one interruption in 2021. The minimum ACI that customer experienced was four ACI (five interruptions in 2020 minus one interruption in

2021). The maximum ACI the customer experienced was six ACI (seven interruptions in 2019 minus one interruption in 2021). On average, the customer had an ACI of five. Due to various factors, such as weather, out-of-scope reliability issues, and budgetary or timing conflicts, a customer may experience more or fewer ACI than expected.

As seen in Table 11B of Company Witness Young's testimony, the average historical ACI of 2,796 customers equates to an average cost per ACI of $1,151.93.

1,983 additional ACI is thus computed when multiplying the specified 2023 budget by the average cost per ACI.

(b) As discussed in OPC DR 9-13a, ACI is a calculation that incorporates cost per ACI based on historical 4R3 candidate data, as well as future budget. It is for this reason that CEMI 4-3P customers cannot be determined from the provided ACI.

(c) Yes. This funding is requested to be recovered from ratepayers as a part of the MDO/CEMI ITN 72252.

(d) In order to align with Exelon best practices across all Operating Companies, Pepco's existing CEMI program would still address customers in this population.

(f) As stated in Witness Young's testimony, the $2.3 million investment is based upon 2023 budget and does not specify budget for years 2024-2026. Please refer to CEMI/MDO ITN 72252 for more information regarding 2023 spend.

(g) Yes. All funding analyzed associated with the CEMI-4R3 PIM utilizes strictly capital expenditures.

(h) The Avoided Customer Interruptions calculation (1,983), refers to the sum of all customer interruptions, on average, that would be reduced in Year 3 of the CEMI tracking period for all CEMI4R3 candidates.

The CEMI-4R3 PIM targets (117/195) express how many customers experience four outages over three consecutive years.

(i) This breakdown is not available, as the focus of work is not based on customer class, but rather pockets of customers with repeat outages.

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 15
Please refer to Witness Young's testimony, page 78. Regarding tables 11A and 11B:

(a) Provide these tables in Excel with all supporting workpapers, calculations, and assumptions.

(b) Please explain and quantify and how these calculations relate to the proposed inventive mechanism for CEMI-4R3.

(c) Please explain whether these tables include the potential PIM payment or penalty.

(d) For table 11A, please provide the number of customers avoided in each customer class shown in the table.

(e) For Table 11B, please explain what the "Min", "Avg.", and "Max" columns indicate.

(f) Does Table 11B indicate the CMI program was cost-effective? (Please explain.)

(g) For each year shown in Table 11B, please provide the cost-effectiveness results in Excel with supporting workpapers and calculations and explain if the program was cost-effective.

RESPONSE:

(a) Table 11A is the output from the ICE calculator, please see response to OPC DR 9-12.

Both Table 11A and Table 11B can be found in OPC DR 9-15 Attachment.

(b) Both tables are intended to quantify the benefits associated with the CEMI-4R3 PIM.

Table 11A utilizes the ICE calculator, which estimates the overall benefits, in dollars, resulting from expected improved reliability. Per Q132 in Company Witness Young's testimony on page 77, the resulting benefits from this table equates to a 180% benefit-to-cost.

Table 11B utilizes past customer interruption data for CEMI-4R3 candidates to quantify the cost of each avoided customer interruption, in order to identify how many interruptions can be avoided based on available budget.

(c) Neither table includes any potential PIM payment or penalty; it is simply intended to quantify the benefits, in order for a CEMI-4R3 PIM to proceed. Please see OPC DR 9-15 Attachment.

(d) Please see response to OPC DR 9-13(c).

(e) Please see response to OPC DR 9-13(a).

(f) Table 11B simply shows the cost per ACI so that a number of avoided customer interruptions can be determined given future budget. Cost-effectiveness can be identified with the quantifiable benefits provided by ICE Calculator in Table 11Al, please see response to OPC DR 9-15(b).

(g) Please see response to OPC DR 9-15(b) and 9-15(f).

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 17
Regarding the CEMI-4R3 PIM, does Pepco have a financial disincentive to reduce the number of CEMI-4R3 customer? (Please explain.)

RESPONSE:
No. As stated in Q132 in Company Witness Young's Direct Testimony on page 77, a positive benefit-to-cost ratio is expected by reducing CEMI-4R3 customers. It would also satisfy the Company's commitment to a world-class customer experience.

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 18
If the Commission does not approve the associated PIM, would Pepco move forward with meeting its proposed reductions to CEMI-4R3 customers? (Please explain why or why not.)

RESPONSE:
If the PIM is not approved, the Company's existing CEMI program would still address customers in this population, per Exelon-wide best practice.

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 22
Please provide total Pepco Maryland emissions (in metric tons CO_2e) in total and by business area (e.g., generation, buildings, vehicles, etc.) from 2010-2022 on an annual basis.

(a) Please provide this on a scope 1, 2, and 3, basis, respectively, and categorize emissions within each scope (generation, buildings, etc.).

(b) Please explain how Pepco categorizes its generation – is this considered scope 1, 2, or 3 emissions, and why?

RESPONSE:

(a) Scope 1&2 emissions are available for this metric. This metric does not consider Scope 3 emissions. Pepco does not have available data for its emissions from 2010-2014, since its GHG program was not baselined until 2015.

(b) Pepco does not have generation assets, and this is not considered in its GHG Emissions Reductions PIM.

Please see OPC DR 9-22 Attachment Electronic Only for GHG Emissions.

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 24
Refer to Young testimony at page 79 regarding the fleet electrification program. Please explain whether Pepco will own and put into rate base the electric vehicles and required charging infrastructure.

(a) Please provide the forecasted amount of these expenditures from 2024-2026 on an annual basis and indicate the percentage of these amounts that are capital vs. expense.

(b) Please provide the number of vehicles expected to be replaced with electric vehicles annually from 2024-2026. (Please provide supporting workpapers and calculations in Excel.)

(c) Please provide the number of vehicles expected to be replaced annually from 2024-2026 with electric vehicles if the PIM is granted. (Please provide supporting workpapers and calculations in Excel.)

(d) How many new vehicles (categorize into EVs and internal-combustion engine vehicles) does the Company purchase each year? (Please provide for each of the previous five years.)

RESPONSE:

(a-c) Please see OPC DR 9-24 Attachment A Electronic Only for Pepco costs.

(d) Please see OPC DR 9-24 Attachment B Electronic Only.

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 26

Refer to Young testimony at page 80 regarding the SF6 Emission Reduction program:

(a) Please provide the amount of expected expenditures on this program in 2024, 2025, and 2026, and state what amount or percentage of these expenditures is a capital expense. (Please provide in Excel with references to witness testimony and workpapers where applicable.)

(b) Please provide the amount of funds that have been expended from 2010-2022 that have reduced SF6 emissions, including all supporting workpapers and calculations in Excel. (Please state the percentage of these expenditures that are capital or expense.)

(c) Does the Company have a financial disincentive to replace SF6 breakers? (Please explain why or why not.)

(d) Does the Company have a financial disincentive to detect and repair SF6 breakers? (Please explain why or why not.)

(e) Does the Company have any existing corporate goals related to reducing SF6 emissions? (If yes, please provide the goals.)

(f) Does Pepco plan to implement the SF6 Emission Reduction Program as proposed regardless of whether the Commission approves its proposed GHG Performance Metric? (If not, please explain how Pepco would modify the SF6 Emission Reduction Program.)

RESPONSE:

(a) Cost data is not accumulated for this PIM.

(b) Cost data is not accumulated for this PIM. The Company's current GHG emissions reduction performance metrics are voluntary commitments that expand our long history of taking action to improve the environment. Taking the necessary steps now to limit severe weather brought on by climate change is the right thing to do as a company and for our community. Creating a cleaner, smarter, and more resilient energy system will reduce emissions and help maintain a strong foundation of safe, reliable, and affordable energy for all customers in Maryland now and in the future.

(c) The Company does not have a financial disincentive to replace SF6 breakers.

(d) The Company does not have a financial disincentive to detect and repair SF6 breakers.

(e) Yes, the Company has established a 1% or less leak rate for its SF6 related equipment. Additionally, the Company has climate reduction goals which SF6 breaker replacements and repairs to reduce its GHG emissions.

(f) If the PIM is not approved, the Company will still execute the GHG Emissions reduction program, however its carbon emissions reduction efforts will be achieved at a slower pace.

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 29
Young testimony at page 81 states the "purpose of the Building Energy Usage program is to […] find reductions to the Company's overall GHG emissions through purchasing and installing renewable energy for facilities, performing solar installations, and using cleaner substation infrastructure at Pepco MD substations."

(a) Please provide the forecast amount of expenditure in total and for each of these activities for 2024, 2025, 2026. (Please provide the percentage or amount of the expenditures that will be capital vs. expense in each year.)

(b) Please provide historical expenditures in total and on each of the listed activities from 2015-2022 and provide the percentage of expenditure that was capital vs. expense.

(c) Does the Company have any existing corporate goals related to reducing energy usage at its buildings? (If yes, please provide those goals.)`

(d) Does the Company expect operational savings from the Building Energy Usage program? (If yes, how will those savings be passed onto customers.)

(e) Does the Company have a financial disincentive to purchase and install renewable energy for its facilities? (Please explain.)

(f) Does the Company have a financial disincentive to install solar on its facilities? (Please explain.)

(g) Does Pepco plan to implement the Building Energy Usage Program as proposed regardless of whether the Commission approves its proposed GHG Performance Metric? (If not, please explain how Pepco would modify the Building Energy Usage Program.)

RESPONSE:

(a) The company does not currently have any cost structure for the Building Energy Usage program. Clean energy improvements are based upon results of subsequent building energy audits which are done off of the square footage (size) of the building.

(b) See answer OPC DR 9-29(a).

(c) Yes, the company is seeking to reduce its overall operations driven greenhouse gas emissions focusing on energy efficiency and clean electricity for our buildings and substations.

(d) The company has not projected its operational savings from its building energy usage program to understand customer impact.

(e) The company does not have a financial disincentive to purchase and install renewable energy for its facilities.

(f) The company does not have a financial disincentive to install solar on its facilities.

(g) If the PIM is not approved, the Company's existing Building Energy Usage program would still address its carbon emissions reduction efforts.

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 9

QUESTION NO. 41
Please provide the number of labor hours/days it takes to remove a PCB distribution transformer. (Please provide the historical average from 2015-2022.)

RESPONSE:
On average, it takes two linepersons, approximately 6 hours on average to remove a PCB overhead distribution transformer, considering pole configuration, proximity, rubber cover up needed and location of the pole. Historical average is not available.

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 24

QUESTION NO. 2
OPC data request number 9, question 35 (a), requested Table 12 from witness Young's testimony at page 82 "in Excel with all supporting workpapers, calculations, and assumptions." However, the Company's attached response provides a different table wherein the numbers slightly differ from Table 12. For example, total building emissions cannot be computed because "stationary combustion" does not have values, fleet vehicle usage is shown to be 2,732 in 2024 versus 2,581 in Table 12, and other differences.

(a) Please provide an Excel version of Table 12 with supporting workpapers and calculations.

(b) Please explain why the values in the attachment to OPC 9-35 differ from Table 12 of witness Young's testimony, or if they do not, how to explain the differences cited in this question.

(c) Regarding the Excel attachment to OC DR 9-35, please provide the following:

(i) Please explain the column headers "If PIM is approved" and "If PIM is not approved columns" and the basis for this data.
(ii) Please explain why 2024 emissions are lower for the "PIM approval" column since it is will be 2024 in 2 months.
(iii) Please explain why emissions are flat from 2024 to 2025 if PIM is not approved.

RESPONSE:

(a) See OPC DR 24-2(a) Attachment Electronic Only.

(b) Pepco's GHG emissions are reforecast quarterly based upon actualized performance. Internal GHG Targets are set based upon third quarter actualized data. Upon the conclusion of a calendar year, the data is verified by a third party at the end of the second quarter of the subsequent year. The data originally provided represented the proposed performance based upon the available data at that time. OPC DR 24-2(a) Attachment represents the revised GHG estimates.

(c) (i) If the PIM is not approved, the Company's GHG reduction would stay at the Company's baseline performance which is shown as in the chart as Pe performance. If the PIM is approved, performance Rewards and Penalties are shown in response to OPC DR 24-7(a).
(ii) Refer to answer OPC DR 24-2(c) i.
(iii) Refer to revised attachment OPC DR 24-2 (a) and explanation on OPC DR 24-2 (b).

SPONSOR: Amber C. Young

Current EU-wide Goal Program End

Exelon reduce 15% by 2022

PEPCO GHG Inventory

Current Assumptions: EIA Grid Outlook, 50% increase in electric through 2050

Does **NOT** yet have the DC building emissions reduction goal

						Ops-Driven Through 2020	Ops-Driven	36%	Increase
	Adjusted/Verified	Adjusted/Verified	Verified	Verified	Verified	Verified	Preliminary		
PEPCO	BASELINE	2016	2017	2018	2019	2020	2021	2022	2023
All Scope 1, 2 & Relevant 3 EMISSIONS	33,803	25,985	21,144	21,395	19,204	22,458	21,666	21,677	20,073
FORMAL CORP ACCOUNTING: TOTAL SCOPE 1 & 2	33,803	25,985	21,144	21,395	19,204	22,458	21,666	21,677	20,073
Operations-Driven (Scope 1 & 2)	33,803	25,985	21,144	21,395	19,204	22,458	21,666	**21,677**	20,073
NOT-TO-EXCEED TARGET									
Operations-Driven (Scope 1 & 2)	BASELINE	2016	2017	2018	2019	2020	2021	Projected	Projected
Stationary Combustion	34	29	5	5	5	5	5	5	5
Building Energy Usage - Electricity	20,952	17,133	14,508	14,391	13,466	14,913	16,950	16,454	14,850
Building Energy Usage - Natural Gas	-	-	-	-	-	-	-	-	-
Building Energy - Steam and Chilled Water	-	-	-	-	-	-	-	-	-
Gas Plant Gas Usage	-	-	-	-	-	-	-	-	-
Fleet Vehicle Fuel Usage	4,042	3,557	3,164	3,136	2,899	2,730	2,567	2,899	2,899
SF6 Leakage	8,775	5,266	3,467	3,863	2,834	4,810	2,143	2,318	2,318
Net Methane Leakage (gas systems / coal pile)	-	-	-	-	-	-	-	0	-
HFC/PFC Refrigerant Leakage (non-ODS only)	-	-	-	-	-	-	-	0	-
CO2 Usage/Leakage	-	-	-	-	-	-	-	0	-
ODC Refrigerant Emissions (not included in Scope 1 & 2)	-	0	-	-	-	-	-	0	-

				2030 Goal Planning
				Scope 1, 2 & 3 Full 1 & 2 Ops Driven Fleet
2024	2025	2026	2027	2028
22,742	22,722	22,702	22,683	#DIV/0!
22,742	22,722	22,702	22,683	12,055
22,742	22,722	22,702	22,683	12,055
Projected	Projected	Projected	Projected	Projected
10	10	10	10	5
15,440	15,440	15,440	15,440	6,832
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
2,581	2,561	2,541	2,522	2,899
4,711	4,711	4,711	4,711	2,318
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
-	-	-	-	-
				-
				-
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				-
				-
				#DIV/0!
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				#DIV/0!

Percent Reduction Projected	Reductions Projected	Reductions needed for 50%
#DIV/0!	#DIV/0!	16,902
76%	25,536	16,902
76%	25,536	16,902
43%	1,722	2,021

2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
10,451	8,267	21,068	20,508	19,948	19,387	18,827	18,267	17,707	17,146	16,586	16,026	15,466	14,905	14,345
10,451	8,267	21,068	20,508	19,948	19,387	18,827	18,267	17,707	17,146	16,586	16,026	15,466	14,905	14,345
Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected
5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
5,228	3,624	16,454	15,923	15,392	14,860	14,329	13,798	13,267	12,736	12,204	11,673	11,142	10,611	10,079
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2,899	2,320	2,291	2,262	2,233	2,204	2,175	2,146	2,117	2,088	2,059	2,030	2,001	1,972	1,943
2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318	2,318
-	0	-	-	-	-	-	-	-	-	-	-	-	-	-
-	0	-	-	-	-	-	-	-	-	-	-	-	-	-
-	0	-	-	-	-	-	-	-	-	-	-	-	-	-
-	0	-	-	-	-	-	0	0	0	0	0	0	0	0
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2044	2045	2046	2047	2048	2049	2050
#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
13,785	13,225	12,664	12,104	11,544	10,984	10,424
13,785	13,225	12,664	12,104	11,544	10,984	10,424
Projected	Projected	Projected	Projected	Projected	Projected	Projected
5	5	5	5	5	5	5
9,548	9,017	8,486	7,954	7,423	6,892	6,361
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-
1,914	1,885	1,856	1,827	1,798	1,769	1,740
2,318	2,318	2,318	2,318	2,318	2,318	2,318
-	-	-	-	-	-	-
-	-	-	-	-	-	-
-	-	-	-	-	-	-
0	0	0	0	0	0	0
-	-	-	-	-	-	-
-	-	-	-	-	-	-
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#DIV/0! MWh

GHG Conversion Factors

Program	**Comparable Metric**	**onversion Facto**
SF6 - lbs	SF6	22,800.000
SF6 - lbs	Total SF6 Inventory	
Building Energy	MWh	930.215
Building Chilled	lbs CO2e / ton-hr	0.843
Building Steam	lbs CO2e / Mlb	144.201
Biodiesel B10	Gallons	20.557
Biodiesel B20	Gallons	18.304
Diesel	Gallons	22.810
Biodiesel (B5)	Gallons	21.684
E-10Unleaded	Gallons	17.671
E85 Ethanol	Gallons	3.0865
Non-Fleet Gasol	Gallons	19.427
Non-Fleet Diesel (gallons) - generators, offsite retail purchases	Gallons	22.586
Non-Fleet Gasoline (gallons) - Echo trailer and emergency vehicles	Gallons	19.427
Non-Fleet propa	Gallons	12.661
Project HERE - I	Pounds	3.200
Industrial Recov	Copper per poun	4.760
Industrial Recov	Aluminum per po	7.23
Industrial Recov	Steel per pound	1.85
Industrial Recov	Lead per pound	4.01
Industrial Recov	Scrapped Transf	4.42
Industrial Recov	Scrapped Powe	4.42
Used Oil Reclain	Gallons	0.01117
R11	pounds of CO2	3800
R22	pounds of CO2	1,500
R134A	pounds of CO2	1,430

Other Conversions

Program	**Comparable Metric**	**onversion Facto**
Natural Gas con	Pounds of CO2 / 1000 cubic feet gas	120.142
Natural Gas con	Pounds of CO2 / billion btu	117,097.950
Fuel Oil combus	Pounds of CO2 / billion btu	163,669.462
Various	Pounds to metric tons	2,204.620
Natural Gas	Cubic feet per therm	100.000
Various	Pounds to Short Tons	2,000.000
LNG Natural Gas	Pounds of CO2 / dekatherm	120.142
Propane Plant Pr	Pounds of CO2 / gallon	12.686
Threshold	95%	105%
Distinguished	85%	115%

Spreadsheet Labels

Year	2017

r
PJM Residual Emissions Rate w egrid CH4 and N2O 2022
Represents Direct portion specific to B-20 fuel (supplemental biomass portion omitted) with TCR simplified estimate method for N2O and CH4
Represents Direct portion specific to B-20 fuel (supplemental biomass portion omitted) with TCR simplified estimate method for N2O and CH4
Incorporates the TCR simplified estimation method for CH4 and N20 component - this will be revised for the final corporate inventory at the end of the year with calculations based on mileage information.
Incorporates the TCR simplified estimation method for CH4 and N20 component - this will be revised for the final corporate inventory at the end of the year with calculations based on mileage information.
Incorporates the TCR simplified estimation method for CH4 and N20 component - this will be revised for the final corporate inventory at the end of the year with calculations based on mileage information.
Represents Direct portion specific to E85 fuel (supplemental biomass portion omitted) with TCR simplified estimate method for N2O and CH4
Stationary Combustion - Emergency Generators
Stationary Combustion - Emergency Generators
Stationary Combustion - Emergency Generators
Stationary Combustion - Emergency Generators - includes CH4 and N2O
WARM Model June 2014
WARM Model June 2014
WARM Model June 2014
WARM Model June 2014
WARM Model June 2014
WARM Model June 2014
WARM Model June 2014
ComEd Vendor specific factor

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POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 24

QUESTION NO. 3
Pepco's response to OPC DR 9-26 (a) states "cost data is not accumulated for this PIM."

(a) Please explain whether the costs to remove, repair, or replace SF6 breakers pursuant to this PIM is paid for by ratepayers or shareholders.

(b) Please explain the conditions under which the cost is a capital or O&M expense.

(c) Please provide an estimate of the percentage of costs to eliminate SF6 emissions have been capital vs. expense. Please provide supporting workpapers and assumptions.

RESPONSE:

(a) The costs related to the Company achieving its proposed PIM reward targets have not been included in the operational spending plans for recovery from ratepayers at this time. If the Company were to spend those amounts in order to achieve its PIM reward target, that would be reflected in the Company's actual results in its annual information filing and would be considered for recovery in a future reconciliation and prudency review.

(b) The costs depend upon the maintenance requirements of the breaker. The maintenance costs associated with units of property for repair are recorded to the appropriate O&M expense account as incurred. The units of property for replacement are recorded to the appropriate capital account as incurred. For utility assets The Company seeks recovery within our Cost of Removal rates.

(c) No cost data analysis has been performed. Estimations have been generated to delineate capital vs expense cost assumptions.

SPONSOR: Amber C. Young and Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO OPC DATA REQUEST NO. 24

QUESTION NO. 7
Please refer to the following statement on page 67 of Witness Leming's testimony: "However, as an additional feature, Pepco is also proposing a satisfactory performance range for each performance metric. Annual rewards are earned if the Company executes or exceeds its annual target, which is being set at the top end of a range of satisfactory performance. Penalties would be assessed on the Company if performance falls below a satisfactory level (defined as the low end of the satisfactory range proposed by the Company). No reward or penalty would occur if performance falls within the satisfactory performance range between the reward and penalty performance."

(a) For the GHG performance metric, please fill out the out the cells marked with an asterisk (*) in the following table to identify the reward, satisfactory, and penalty performance levels for each year of the MRP, in metric tons of CO_2e.

Performance level	**2024**	**2025**	**2026**	**2027**
	Metric tons CO2e			
Reward	*	*	*	*
Satisfactory range	*	*	*	*
Penalty	*	*	*	*

(b) For the PCB performance metric, please fill out the out the cells marked with an asterisk (*) in the following table to identify the reward, satisfactory, and penalty performance levels for each year of the MRP, in number of PCB transformers removed.

Performance level	**2024**	**2025**	**2026**	**2027**
	Number of existing PCB-containing equipment removed			
Reward	*	*	*	*
Satisfactory range	*	*	*	*
Penalty	*	*	*	*

(c) For the CEMI performance metric, please fill out the out the cells marked with an asterisk (*) in the following table to identify the reward, satisfactory, and penalty performance levels for each year of the MRP, in number of customers interrupted.

Performance level	**2024**	**2025**	**2026**	**2027**
	Number of CEMI-4R3 customers			
Reward	*	*	*	*
Satisfactory range	*	*	*	*

Penalty	*	*	*	*

RESPONSE:

(a) The satisfactory metric is not a single amount, but rather a range. Performance above the high end of this range results in a reward and performance below the low end of this range results in a penalty. Please see Table 12 on Page 82 of the Direct Testimony of Company Witness Young for the proposed top and bottom metrics of the satisfactory range for the GHG Emissions Reductions Metric. The "Baseline" total reductions is the low end of the Satisfactory range and then "Accelerated" total reductions is the high end of the Satisfactory range.

Performance level	**2024**	**2025**	**2026**	**2027**
	Metric tons CO2e			
Reward	Less than 22,731	Less than 22,711	Less than 22,691	Less than 22,672
Satisfactory range	22,732 – 35,037	22,712 – 35,037	22,692 – 35,037	22,673 – 35,037
Penalty	Greater than 35,037	Greater than 35,037	Greater than 35,037	Greater than 35,037

(b) The satisfactory metric is not a single amount, but rather a range. Performance above the high end of this range results in a reward and performance below the low end of this range results in a penalty. However, if the Company exceeds the reward removals in any given year, the subsequent year, shall not be penalized. Please see Table 13 on Page 85 of the Direct Testimony of Company Witness Young for the proposed top and bottom metrics of the satisfactory range for the PCB Removal Metric. The "Baseline" total transformer removal is the low end of the Satisfactory range and the "Accelerated" total transformer removal is the high end of the Satisfactory range. Note, there are no metrics for 2027, as the Company's goal is to remove all equipment containing PCB within 3 years, as discussed on page 84, lines 9 through 14 of the Direct Testimony of Company Witness Young.

Performance level	**2024**	**2025**	**2026**	**2027**
	Number of existing PCB-containing equipment removed			
Reward	20	15	11	N/A
Satisfactory range	1 – 19	1 – 14	1 – 10	N/A
Penalty	0	0	0	N/A

(c) The satisfactory metric is not a single amount, but rather a range. Performance above the high end of this range results in a reward and performance below the low end of this range results in a penalty. Please see Table 9 on Page 76 of the Direct Testimony of Company Witness Young for the proposed top and bottom metrics of the satisfactory range for the CEMI-4R3 Metric. The proposed range is constant for all years of the MYP.

Performance level	**2024**	**2025**	**2026**	**2027**
	Number of CEMI-4R3 customers			
Reward	0 – 117	0 – 117	0 – 117	0 – 117
Satisfactory range	118 – 194	118 – 194	118 – 194	118 – 194
Penalty	195 or Greater	195 or Greater	195 or Greater	195 or Greater

SPONSOR: Amber C. Young and Robert T. Leming

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO STAFF DATA REQUEST NO. 5

QUESTION NO. 17

Please describe how Pepco accounts for a newly purchased vehicle in terms of the acquisition cost and the asset value over time.

RESPONSE:

Please see the Company's response to MD 9702 Staff DR 5-17.1. and 5-17.2.

SPONSOR: Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO STAFF DATA REQUEST NO. 5

QUESTION NO. 17.1
Is the cost of the vehicle treated as a one-time expense that is recovered via rates or treated in some other way?

RESPONSE:
For vehicles that Pepco purchases, the Company capitalizes the costs and records them to FERC Account 392 (Transportation Equipment) and these costs are included in rate base.

SPONSOR: Robert T. Leming, Amber C. Young

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9702
RESPONSE TO STAFF DATA REQUEST NO. 5

QUESTION NO. 17.2
Is the value of the vehicle after purchase included in rate base and depreciated over time or is it accounted for in some other way?

RESPONSE:
For the vehicles that Pepco purchases, the value is included in the Company's rate base after purchase and depreciated over time.

SPONSORS: Robert T. Leming, Amber C. Young exelon℠

Winter 2023

Investor Meetings

Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of federal securities laws that that are subject to risks and uncertainties. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” “should,” and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic, and financial performance, are intended to identify such forward-looking statements. Any reference to “E” after a year or time period indicates the information for that year or time period is an estimate. Any reference to expected average outstanding shares is exclusive of any equity offerings.

The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) the Registrants' 2022 Annual Report on Form 10-K in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 18, Commitments and Contingencies; (2) the Registrants’ Third Quarter 2023 Quarterly Report on Form 10-Q (filed on November 2, 2023) in (a) Part II, ITEM 1A. Risk Factors, (b) Part I, ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part I, ITEM 1. Financial Statements: Note 12, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants.

Investors are cautioned not to place undue reliance on these forward-looking statements, whether written or oral, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Non-GAAP Financial Measures

Exelon reports its financial results in accordance with accounting principles generally accepted in the United States (GAAP). Historical results were revised from amounts previously reported to reflect only Exelon continuing operations. Exelon supplements the reporting of financial information determined in accordance with GAAP with certain non-GAAP financial measures, including:

- ***Adjusted operating earnings*** exclude certain items that are considered by management to be not directly related to the ongoing operations of the business as described in the Appendix
- ***Adjusted operating and maintenance expense*** excludes regulatory operating and maintenance costs for the utility businesses and certain excluded items as set forth in the reconciliation in the Appendix
- ***Operating ROE*** is calculated using operating net income divided by average equity for the period. The operating income reflects all lines of business for the utility business (Electric Distribution, Gas Distribution, Transmission).
- ***Adjusted cash from operations*** primarily includes cash flows from operating activities adjusted for common dividends and change in cash on hand

Due to the forward-looking nature of some forecasted non-GAAP measures, information to reconcile the forecasted adjusted (non-GAAP) measures to the most directly comparable GAAP measure may not be currently available, as management is unable to project all of these items for future periods.

This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets, and planning and forecasting of future periods.

These non-GAAP financial measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations. Exelon has provided these non-GAAP financial measures as supplemental information and in addition to the financial measures that are calculated and presented in accordance with GAAP. These non-GAAP measures should not be deemed more useful than, a substitute for, or an alternative to the most comparable GAAP measures provided in the materials presented.

Non-GAAP financial measures are identified by the phrase "non-GAAP" or an asterisk (*). Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the appendices and attachments to this presentation.

Who is Exelon?

6 T&D-only utilities
Operate within seven regulatory jurisdictions

4 major metro areas served
Chicago, Philadelphia, Baltimore, and Washington D.C.

19,100
Employees across our operating companies

10.6 million(1)
Electric and gas customers served across our service territories

25,600
Square miles of combined service territory across our jurisdictions

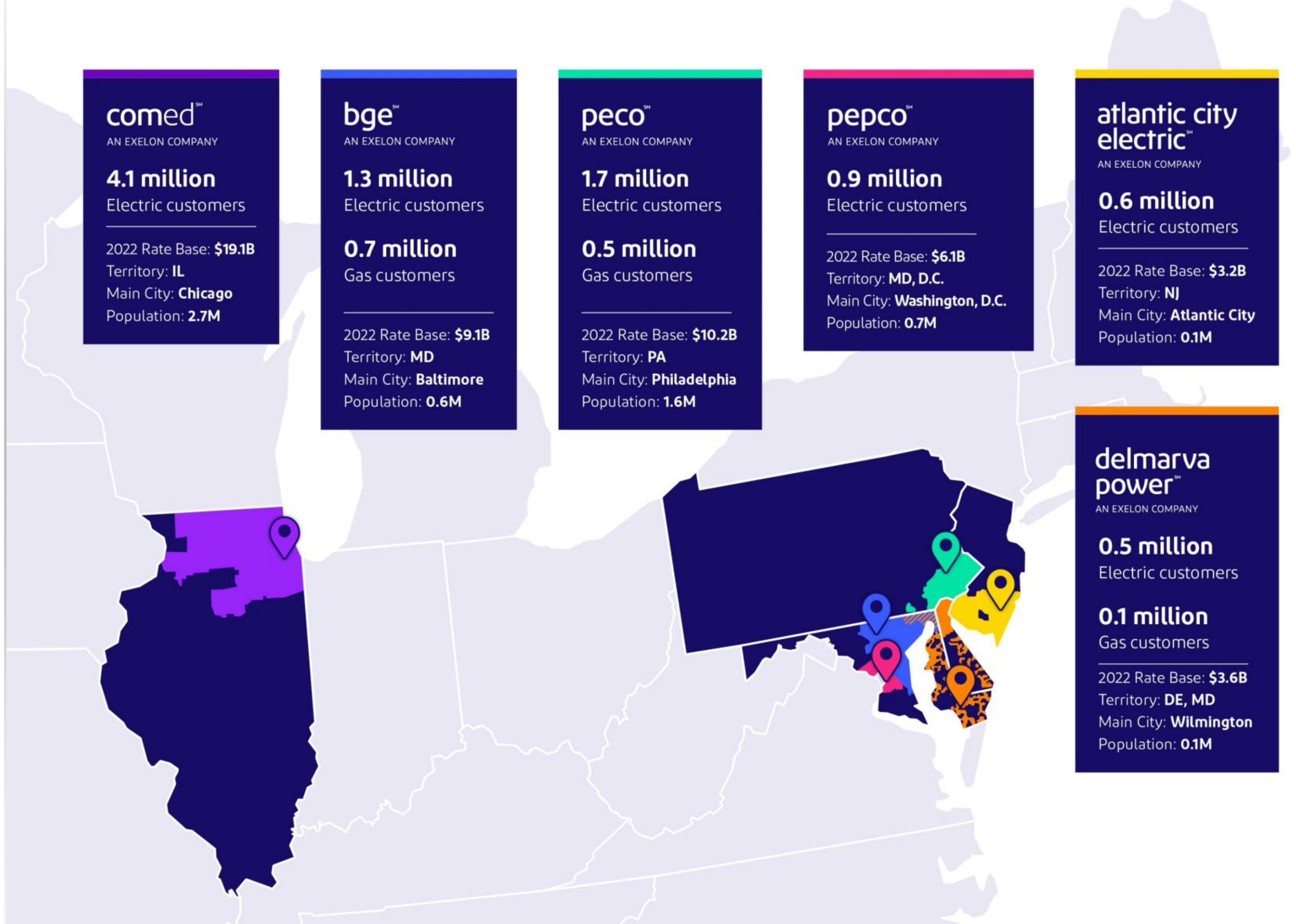
183,540
Circuit miles of electric and gas distribution lines

11,140
Circuit miles of FERC-regulated electric transmission lines

$19.1 billion
Operating revenues recorded at our utilities in 2022

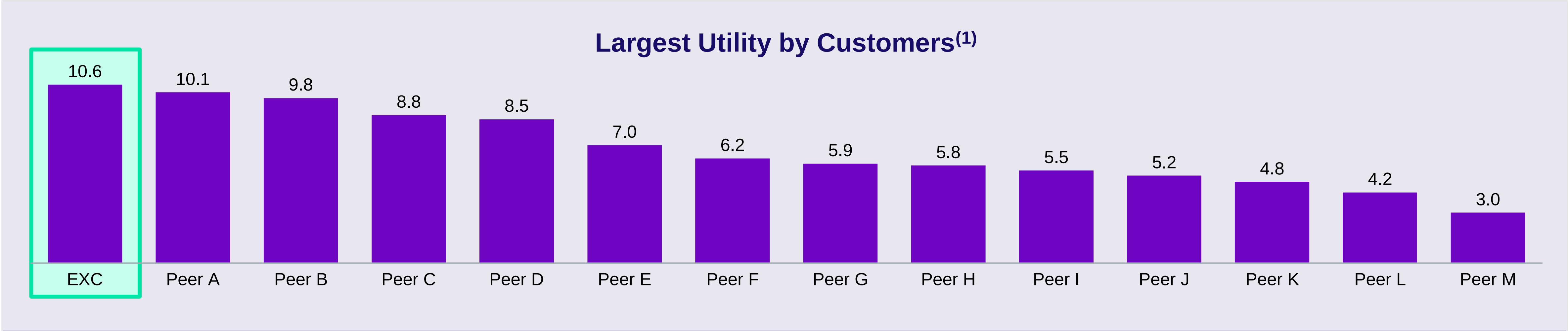
$56.2 billion
Rate base estimate for 2023

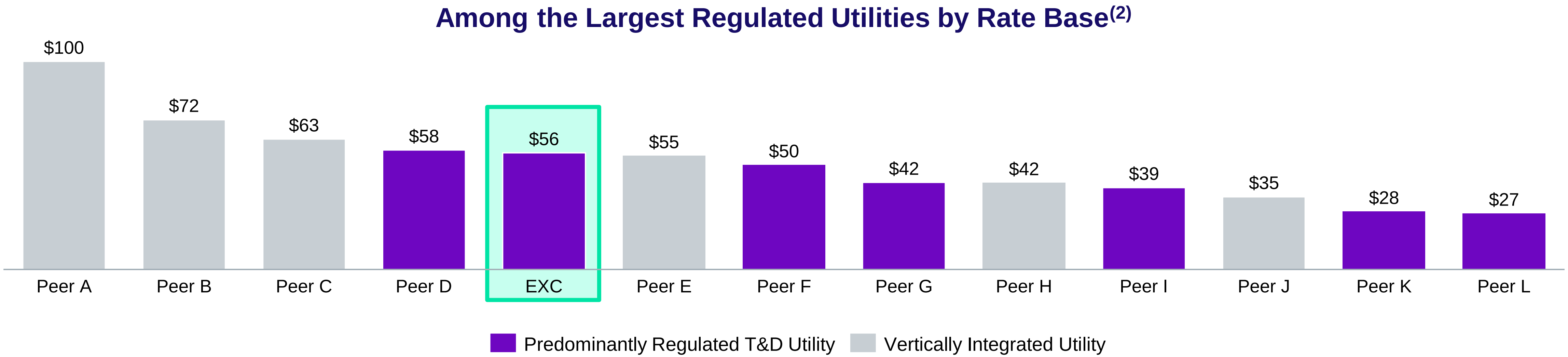
$31.3 billion
Projected capital investment over 2023 through 2026



(1) Customer count reflects the sum of Exelon's total gas and electric customer base; Exelon consolidated customer count may not sum due to rounding

Premier Utility by Scope and Scale





Note: reflects most recent available data as of May 12, 2023
(1) Customer count reflects the sum of Exelon’s total gas and electric customer base.
(2) Includes transmission, distribution and generation; represents 2023E rate base projections as disclosed by the companies if available. For companies that do not disclose 2023E, reflects rate base projection calculated from stated growth rate.

Delivering Sustainable Value as the Premier T&D Utility

SUSTAINABLE VALUE

- ✓ **Strong Growth Outlook:** ~$31.3B of T&D capital from 2023-2026 to meet customer needs, resulting in expected rate base growth of 7.9% and fully regulated T&D operating EPS* growth of 6-8% from 2022-2026(1)
- ✓ **Shareholder Returns:** Expect ~60% dividend payout ratio(2) resulting in dividend growing in-line with targeted 6-8% operating EPS* CAGR through 2026

INDUSTRY-LEADING PLATFORM

- ✓ **Size and Scale:** Largest T&D utility in the country serving 10+ million customers
- ✓ **Diversified Rate Base:** Operate across 7 different regulatory jurisdictions
- ✓ **Large Urban Footprint:** Geographically positioned to lead the clean energy buildout in our densely-populated territories

OPERATIONAL EXCELLENCE

- ✓ **Safely Powering Reliability and Resilience:** Track record of top quartile reliability performance
- ✓ **Delivering a World-Class Customer Experience:** Helping customers take control of energy usage while delivering top quartile customer satisfaction results
- ✓ **Constructive Regulatory Environments:** ~100% of rate base growth covered by alternative recovery mechanisms and ~73% decoupled from volumetric risk

LEADING ESG PROFILE

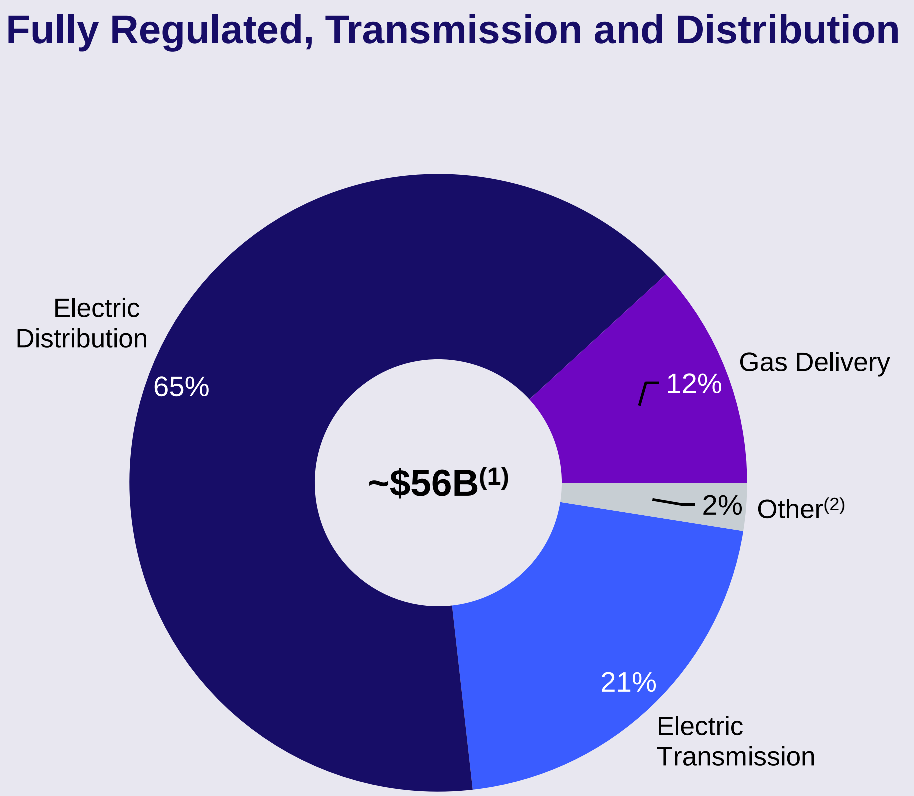
- ✓ **No Owned Generation Supply:** Pure-play T&D utility
- ✓ **Advancing Clean and Affordable Energy Choices:** Building a smarter, stronger, and cleaner energy grid with options that meet customer needs at affordable rates
- ✓ **Supporting Communities:** Powering the economic health of the diverse communities we serve, while advancing social equity

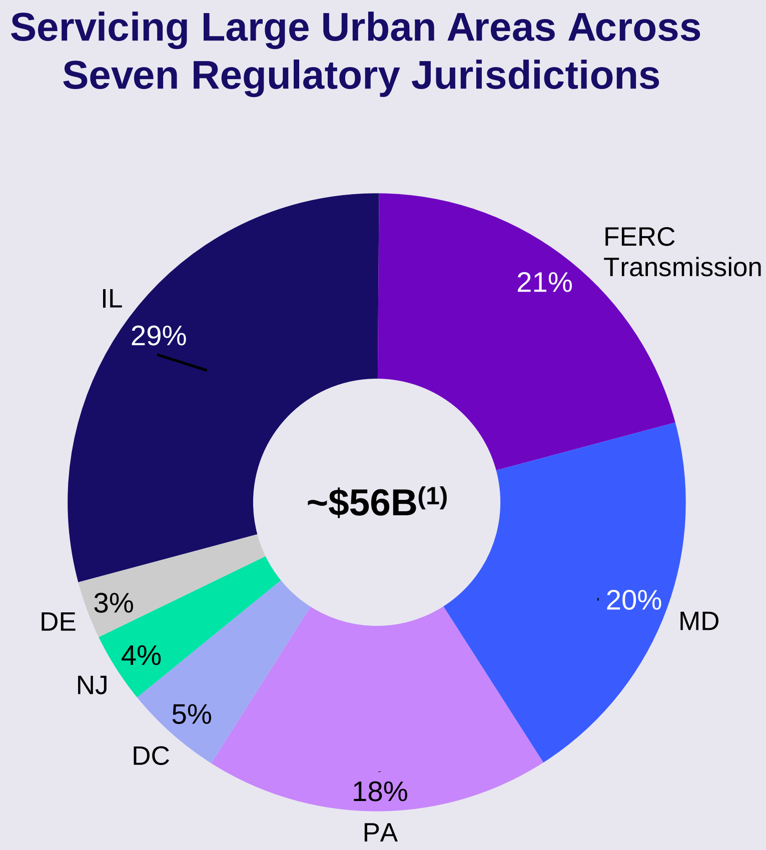
FINANCIAL DISCIPLINE

- ✓ **Strong Balance Sheet:** Maintain balance sheet capacity to firmly support investment grade credit ratings
- ✓ **Organic Growth:** Reinvestment of free cash to fund utility capital programs with $425M of equity in plan

(1) Based off the midpoint of Exelon's 2022 Adjusted EPS* guidance range of $2.18 - $2.32 as disclosed at Analyst Day in January 2022.
(2) Dividend is subject to approval by the Board of Directors.

Diverse, Fully Regulated T&D Utility



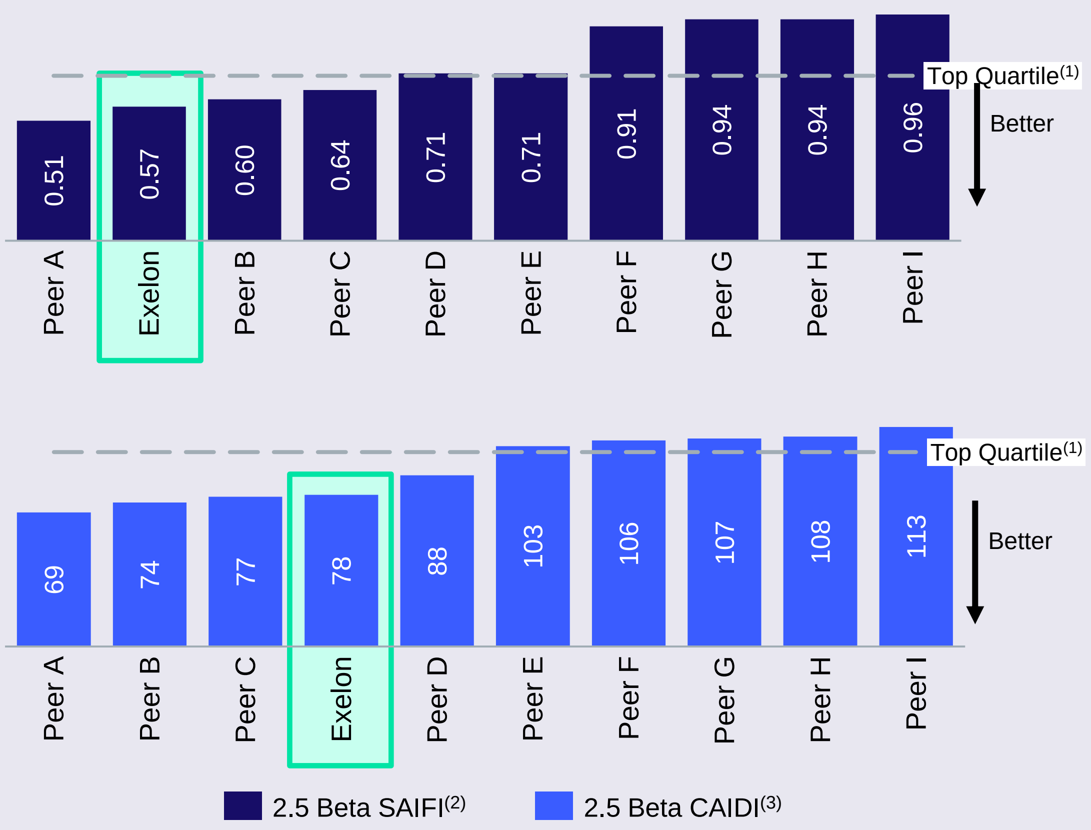


Exelon is a fully regulated, majority-electric T&D operator servicing seven different regulatory jurisdictions

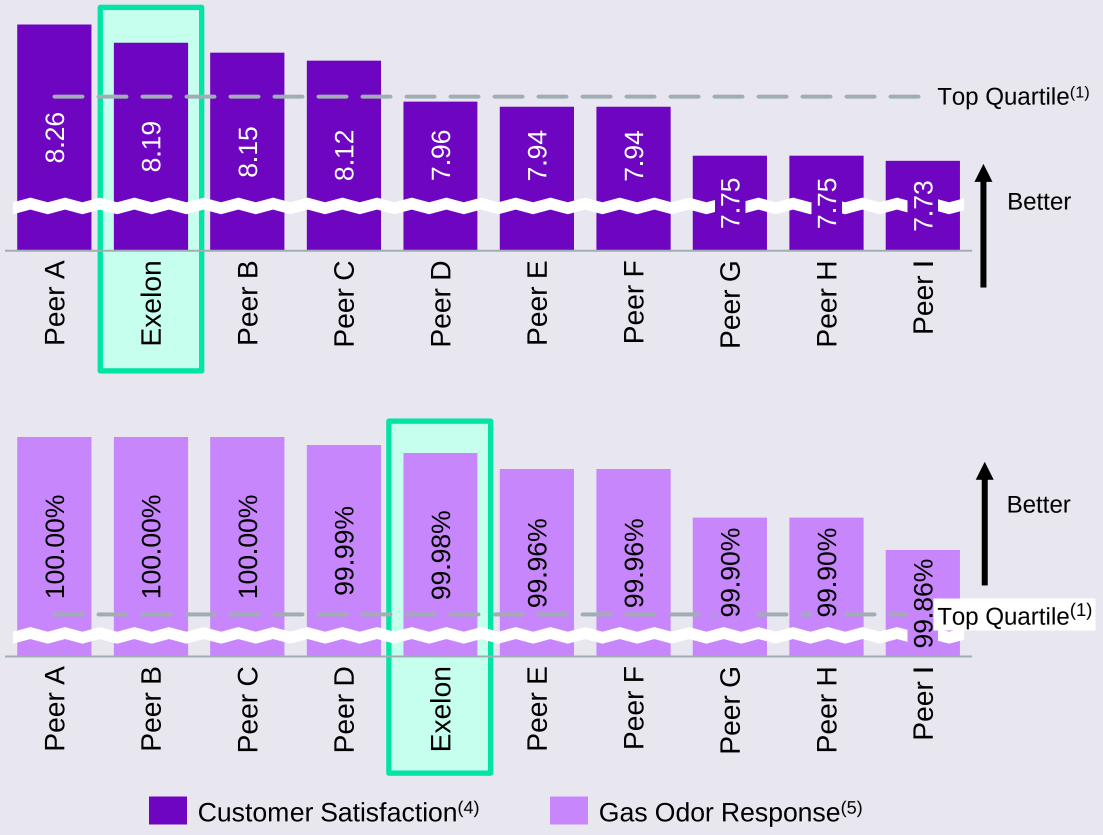
(1) Represents 2023E rate base.
(2) Other includes long-term regulatory assets, which generally earn a return consistent with rate base, including Energy Efficiency and the Solar Rebate Program.

Best-in-Class Operations

Industry-Leading T&D Operator



Delivering a World-Class Customer Experience



Note: reflects 2021 company performance (the latest comparable data set for Exelon and its peers); peer data reflects only a subset (top 10) of the panel of companies that report operational metrics

(1) Quartiles are calculated using reported results by the full panel of peer companies that are deemed most comparable to Exelon's utilities each year; reflects 2020 quartiles to remain consistent with the data used for 2022 benchmarking.

(2) Reflects the average number of interruptions per customer reported by Exelon and 20 comparable peer utilities (sources: *First Quartile (1QC) T&D, PSE&G Electric Peer Panel Survey,* or *EIA*).

(3) Reflects the average time to restore service to customer interruptions reported by Exelon and 20 comparable peer utilities (sources: *First Quartile (1QC) T&D, PSE&G Electric Peer Panel Survey,* or *EIA*).

(4) Reflects the measurements of perceptions of reliability, customer service, price and management reputation by residential and small business customers reported to *Escalent* by Exelon and 18 comparable peer utilities.

(5) Reflects the percentage of calls responded to in 1 hour or less reported by Exelon and 50 comparable peer utilities (sources: *PSE&G Peer Panel Gas Survey* and *AGA Best Practices Survey*).

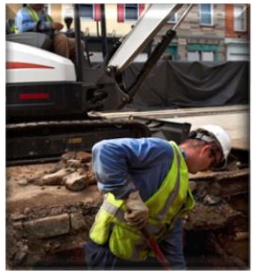
Safely Powering Reliability and Resilience

Undergrounding Cable Initiative

- DC Power Line Undergrounding is a multi-year program to underground more than 20 of the most vulnerable overhead distribution lines, spanning over 6-8 years with work that began in early 2019
- Expected to improve resiliency against major storms and to improve reliability by an estimated 95% on selected feeders

Superconductor Technology

- ComEd is the first utility in the U.S. to permanently install superconductor cable technology at a substation in Chicago's Irving Park neighborhood
- Superconductor technology can support 200 times the current of standard copper wire, and allows electricity to be rerouted creating a backup system that keeps electricity flowing in the event of a major power grid interruption



Gas Replacement Programs

- BGE STRIDE program replaced ~300 miles of gas main and more than 32,000 gas service pipes since 2014, connecting customer properties to gas mains with modern, durable equipment
- Since 2015, PECO has replaced 334 miles of gas mains and approximately 27,000 services to ensure safety and reliability for its customers

Grid Modernization Drives Consistent Reliability Performance(1)

(1) Quartiles are calculated using reported results by the full panel of peer companies that are deemed most comparable to Exelon's utilities each year; quartiles reflect data from two years prior to the indicated year, which is the latest data set available for the entirety of that year.
(2) Reflects the average number of interruptions per customer reported by Exelon and 20 comparable peer utilities (sources: First Quartile (1QC) T&D, PSE&G Electric Peer Panel Survey, or EIA).
(3) Reflects the average time to restore service to customer interruptions reported by Exelon and 20 comparable peer utilities (sources: First Quartile (1QC) T&D, PSE&G Electric Peer Panel Survey, or EIA).
(4) Higher frequency and duration of outages in 2018/2019 were due to minor weather events that were not declared as a major event day, and as a result were not excludable from calculations.

Advancing Clean Energy Choices and Driving Customer Value

Energy Efficiency

- Offer nationally recognized energy efficiency portfolios, including incentives and behavioral programs across all our jurisdictions, saving almost 24.8M MWh in 2022

Smart Meters[1]

- 94.8% and 97.0% of electric and gas customers, respectively, have smart meters that allow greater customer participation in the energy system and enhance power grid operational capabilities

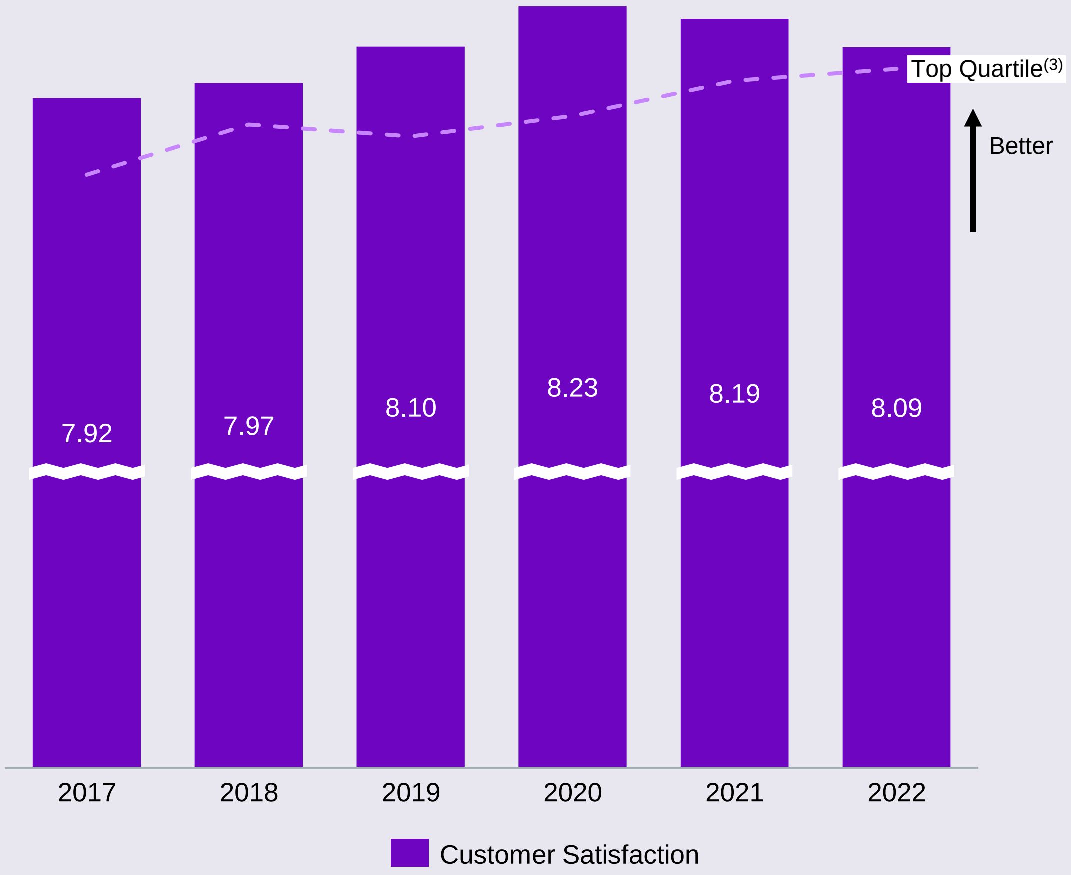
Transportation Electrification

- Enabling the installation of more than 7,000 residential, commercial, and/or utility-owned charging ports across Maryland, Washington D.C., Delaware, and New Jersey
- Rebates and incentives support the development of make-ready infrastructure and/or installation of eligible smart chargers

Distributed Energy Resource (DER) Enablement

- Enabled more than 200,000 customers to connect 3,089 MW of local renewable generation to the grid through 2022

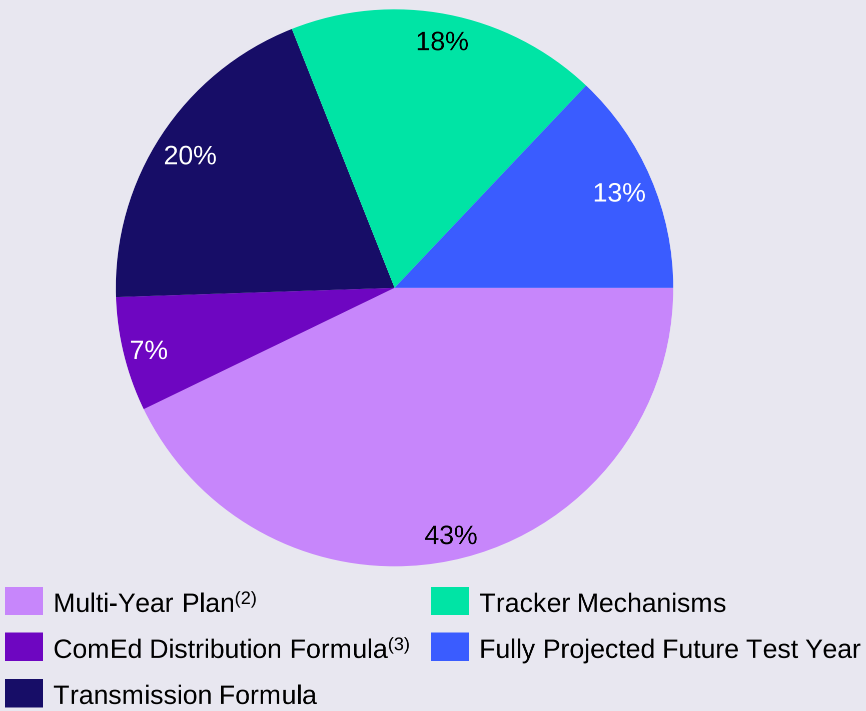
Consistently Delivering Top Quartile Customer Satisfaction Scores[2]



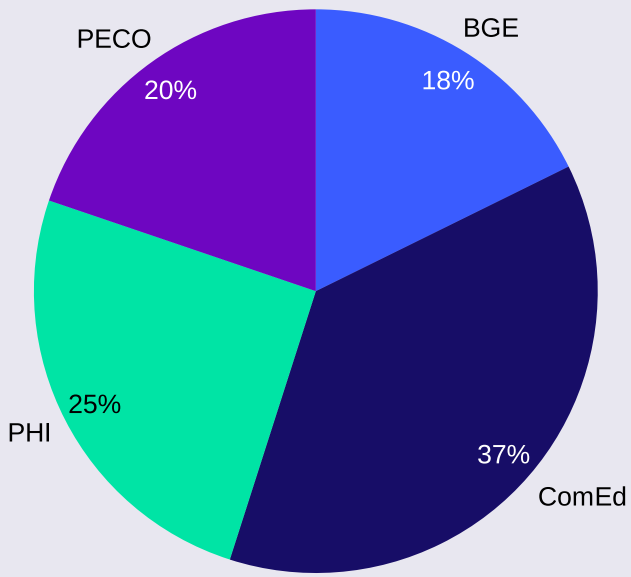
(1) Exelon utility companies, with the exception of ACE, have completed their planned major smart meter program deployments. ACE began deployment in September 2022 and will complete work in 2024.
(2) Reflects the measurements of perceptions of reliability, customer service, price and management reputation by residential and small business customers reported to *Escalent* by Exelon and 18 comparable peer utilities.
(3) Quartiles are calculated using reported results by the full panel of peer companies that are deemed most comparable to Exelon's utilities each year; quartiles reflect data from two years prior to the indicated year, which is the latest data set available for the entirety of that year.

Alternative Regulatory Mechanisms Across Variety of Jurisdictions

2023-2026E Rate Base Growth of $18B[1]



2022 Rate Base Composition



Exelon projects ~$18B of expected rate base growth over 2023 to 2026 to be 100% recovered through alternative recovery mechanisms

(1) Reflects expected rate base growth for 2023E-2026E (calculated from 2022 base year); DPL MD transition from traditional base rates to multi-year plan in 2023 more than offsets projected growth in remaining jurisdictions with traditional base rates (i.e., DPL DE and ACE).
(2) Figure assumes implementation of multi-year rate plan for ComEd (filed on January 17, 2023).
(3) ComEd distribution formula rate expires in 2022, but 2023 effective rates are based on the final formula rate approved in November 2022.

Exelon is an Industry Leader in Sustainability

Environmental

NET-ZERO CLIMATE GOAL

- No owned generation supply
- Targeting a reduction of our operations-driven Scope 1 and Scope 2 emissions by **50% by 2030** and **net-zero for these emissions by 2050** through our Path to Clean

ADVANCING CLEAN AND AFFORDABLE ENERGY CHOICES

- Green Power Connection Program enables interconnection of local renewables
- Energy efficiency programs helped customers save almost **24.8 million MWhs** in 2022

INVESTING IN CLIMATE SOLUTIONS

- Launched the **$20 million** Climate Change Investment Initiative (2c2i) in 2019, driving investment in emerging technologies that support clean energy transition and resilience
  - As of 2022, **64%** of 2c2i investments are in minority and women-led startups and **57%** are headquartered in a city in Exelon's footprint

Social

DIVERSITY, EQUITY & INCLUSION (DEI)[1]

- Executive Committee is **64%** women and people of color
- Created Executive-led **Racial Equity Task Force** in 2020

SUPPORTING OUR COMMUNITIES

- **90** company-sponsored workforce development programs address economic inequities in our communities
- **$2.9 billion** of expenditures with diverse suppliers represented 39% of total utility sourced supplier spend in 2022
- In 2021, launched **$36 million** capital fund to promote equity and economic opportunity in Exelon's communities, along with **$3 million** Exelon HBCU Corporate Scholars Program

ENERGY AFFORDABILITY

- Utility customer bills as a percent of median income is **below** the national average
- Rates in Exelon's service territories are **23%** below the largest U.S. metro cities
- Connected our income-eligible customers to **~$590M** of financial energy assistance in 2022, which was ~**25%** higher than 2021 levels

Governance

STRONG CORPORATE GOVERNANCE ACROSS THE ORGANIZATION

- Ranked **70th out of the S&P 250** in Labrador Advisory Services' 2022 Transparency Awards, which recognizes the quality and completeness of information that top U.S. companies make available to investors
- Executive compensation is tied to customer, strategy, financial, operational and ESG goals
- Stock ownership requirement for executives and directors aligns interests with stakeholders
- Ranked in the top **10% of all S&P companies** in the 2023 CPA-Zicklin Index for Corporate Political Disclosure and Accountability, earning designation as an index Trendsetter with a 95.7% score

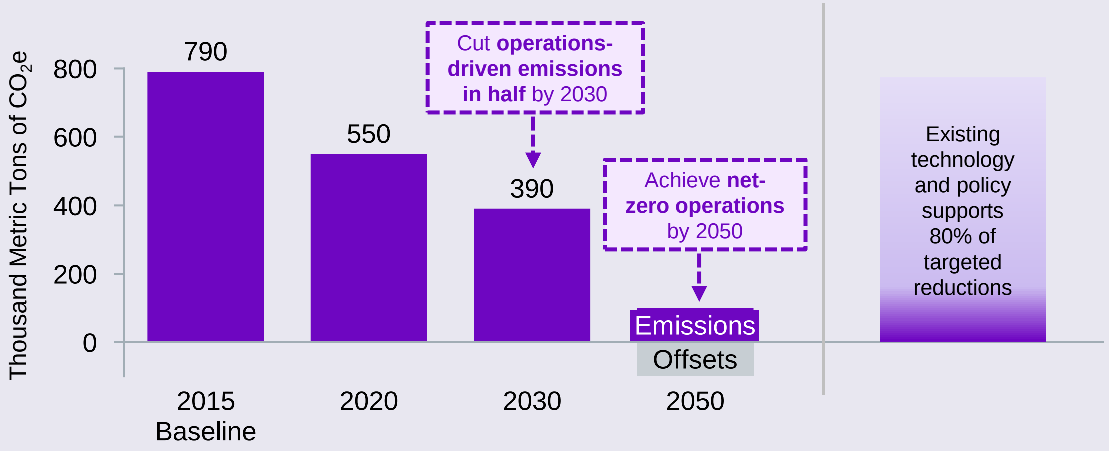
ENHANCING EXELON BOARD DEI[1]

- **89%** of Board members are independent, including independent Board Chair
- **67%** diverse Board of which **56%** are people of color and **44%** are women

(1) Reflects Executive Committee and Board statistics as of September 30, 2023.

Path to Clean: Reaching a Net-Zero Footprint

The Path to Meeting Exelon's Scope 1 and 2, Operations-Driven Emissions Reduction Goals



COMPANY AND OPERATIONS

Reducing Operations-Driven Emissions by 50% by 2030 and Net-Zero by 2050 to Align with National Decarbonization Goals

- Electrify 30% of our light and heavy-duty vehicle fleet by 2025 and 50% by 2030
- Focus on efficiency, conservation and clean electricity for our operations
- Invest in equipment and processes to reduce SF6 leakage from our systems
- Modernize our natural gas infrastructure to minimize methane leaks and increase safety and reliability

Driving Scope 3 Customer Emissions Reductions by Supporting Clean Energy Goals in Our Communities

EMPOWERING CUSTOMERS

Areas for Innovation and Technology Advancement

- Efficient grid management and grid modernization technologies to minimize system losses
- Leak detection technologies to reduce natural gas lifecycle emissions and increase safety
- Transportation electrification, efficiency, and conservation programs for our customers
- Leverage alternative fuels to reduce natural gas lifecycle emissions

COMMUNITY SUPPORT

Areas for Engagement and Advocacy

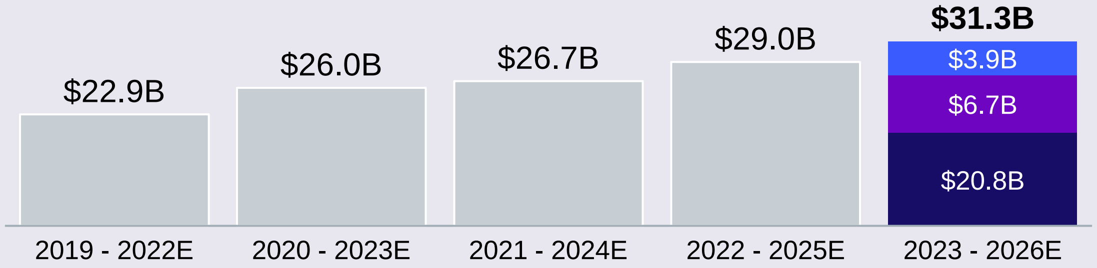
- Partner with communities to develop and implement clean energy solutions that are accessible to all customers
- Understand jurisdictional differences in energy use needs to develop reliable decarbonization solutions
- Invest in and support small businesses that are tackling climate problems in our communities
- Build connected communities that harness digital solutions to integrate clean technologies

Exelon has aligned its corporate goal with the national science-based target, with existing solutions identified for 80% of the reductions, and is proactively investing in pilot technologies and solutions to address remaining 20%

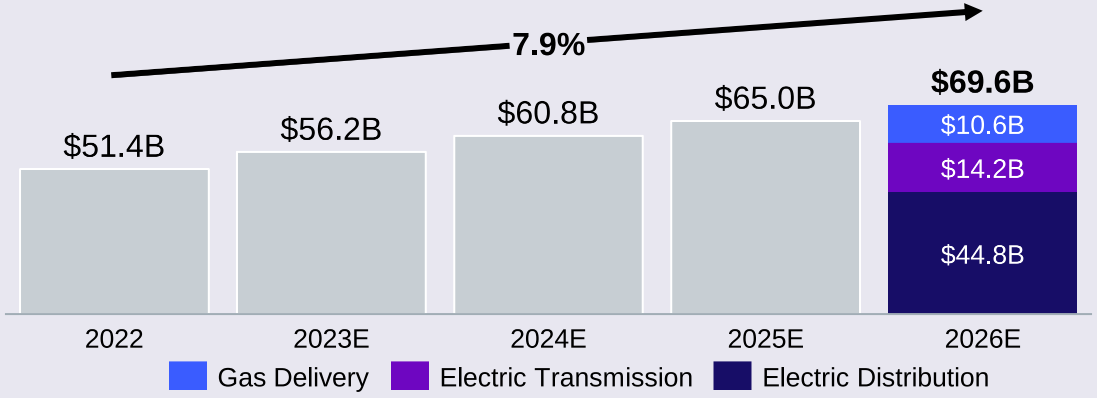
Financial Outlook

Customer Needs and Industry Trends Continue to Support Investment Growth

4-year capital investment[1] profile drives benefits for our customers...



… and translates to **higher rate base**[2] **growth**



Largest T&D Projects in 2023-2026 Capital Plan

comed

Goodings Grove 345kV Transmission

$111 million
from 2023-2026

peco

Elkins Park Building Substation

$45 million
from 2023-2026

bge

Erdman to Summerfield Transmission Expansion

$301 million
from 2023-2026

pepco holdings

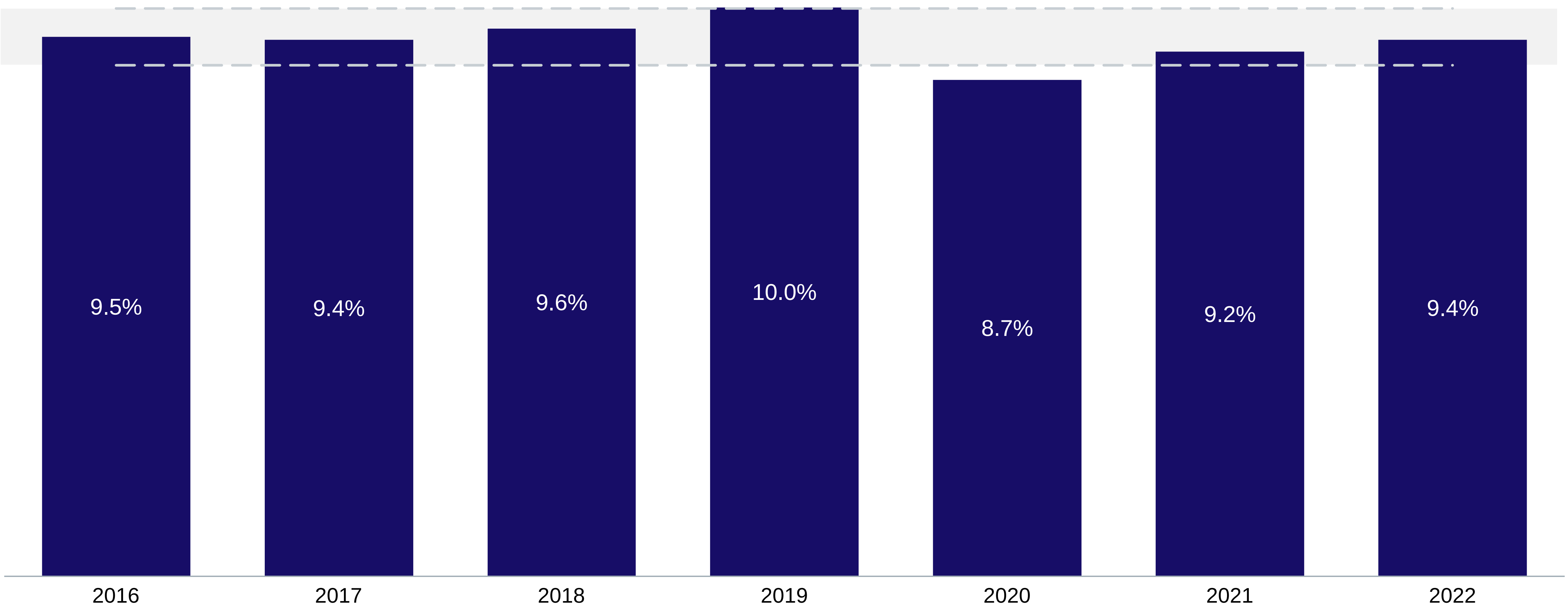
Downtown 34-69kV Resupply

$231 million
from 2023-2026

Exelon's $31.3B low-risk capital plan from 2023 to 2026 results in expected rate base growth of 7.9%

(1) 4-year capital outlook for 2022-2025E reflects capital forecast as presented at Analyst Day 2022; forecast for 2023-2026E as of Q4 2022 earnings call.
(2) Reflects Q4 2022 year-end rate base projections.

Exelon's Annual Earned Operating ROEs*

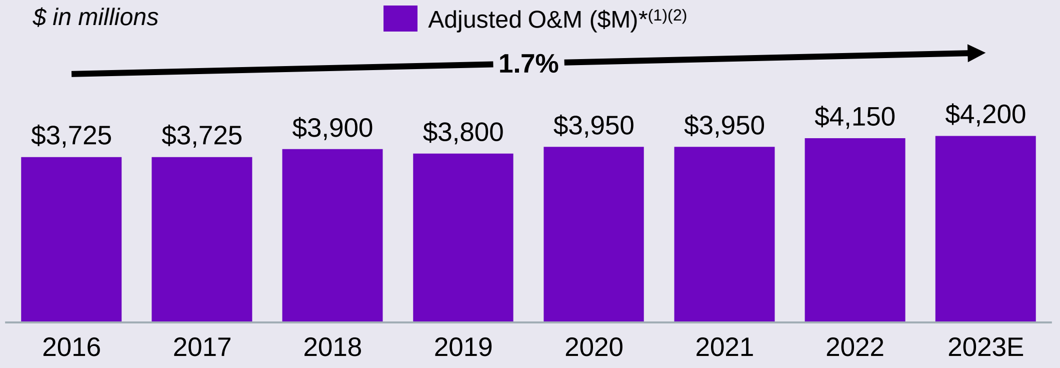


Delivered 2022 operating ROE* within our 9-10% targeted range

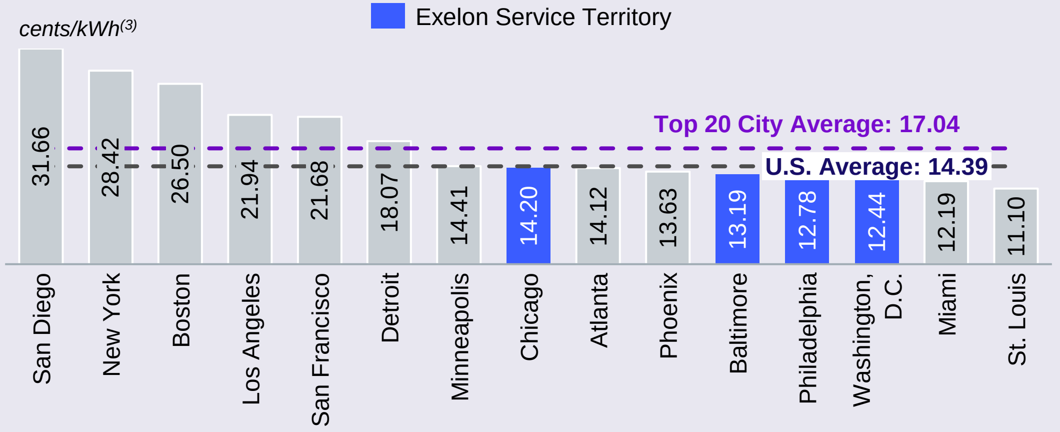
Note: Represents the twelve-month periods December 31, 2016-2022 for Exelon's utilities (excludes Corp). Earned operating ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Gray-shaded area represents Exelon's 9-10% targeted range.

Focused on Managing Costs to Support Affordability

Managing Costs Well Below the Rate of Inflation



Rates 23% Below Largest U.S. Metro Cities



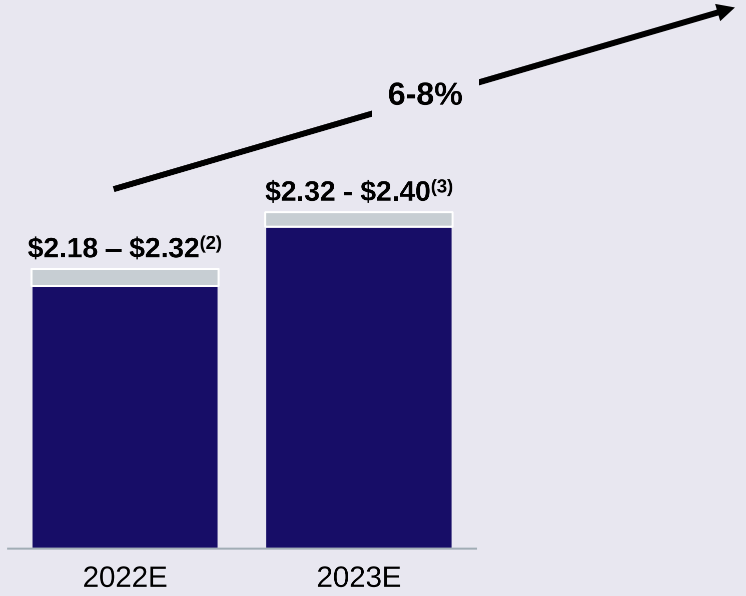
Addressing Customer Affordability Across Multiple Dimensions

- Exelon is well positioned to manage inflationary pressures
  - Working with business partners to mitigate price increases and avoid long lead times through negotiations, utilizing alternative suppliers, and purchasing in bulk
  - World-class Supply organization leveraging economies of scale
  - 44% of labor force is represented, with contract renewals over 2023 to 2027
- Since 2016, adjusted O&M* is projected to increase at an annualized rate of 1.7% through 2023, which is **well below the rate of inflation**, benefitting customer bills by avoiding $500M+ of inflationary impacts[4]
- Beyond Exelon's proven cost management discipline, other elements contribute to efforts to keep total customer bills affordable
  - Carbon Mitigation Credit (CMC) contracts in Illinois
  - Financial assistance programs for income-eligible customers
  - Energy efficiency programs
- Exelon's customers' electricity bills as a % of median income are ~30% below the U.S. average of 2.1%[5]

(1) Reflects adjusted O&M* for Exelon's utilities which includes allocated costs from the shared services company; numbers rounded to the nearest $25M.
(2) 2022 actual adjusted O&M includes $34M of CEJA-related costs at ComEd that were treated as regulatory asset spend in 2022 but reclassified to adjusted operating O&M beginning in 2023.
(3) Source: Edison Electric Institute Typical Bills and Average Rates report for Summer 2022; reflects residential average rates for the 12-month period ending 6/30/2022. Los Angeles and Boston residential average rate data for the 12-month period ending 6/30/2022 sourced from Energy Information Administration (EIA-861M). High-population cities that do not provide data (e.g., Houston) are excluded from analysis. Chart reflects a sample of the top 20 cities for illustrative purposes.
(4) Assuming an average annual 3.2% rate of inflation based on consumer price index as reported by the Bureau of Labor Statistics and IHS across 2016-2023, adjusted O&M costs would have increased by ~$1B over the same time period.
(5) Sources: 2021 EIA Residential Electric Revenue and Customer data by provider for Full-Service Providers, and median income for U.S. using US Census Bureau 2021 ACS 1-Year Estimates.

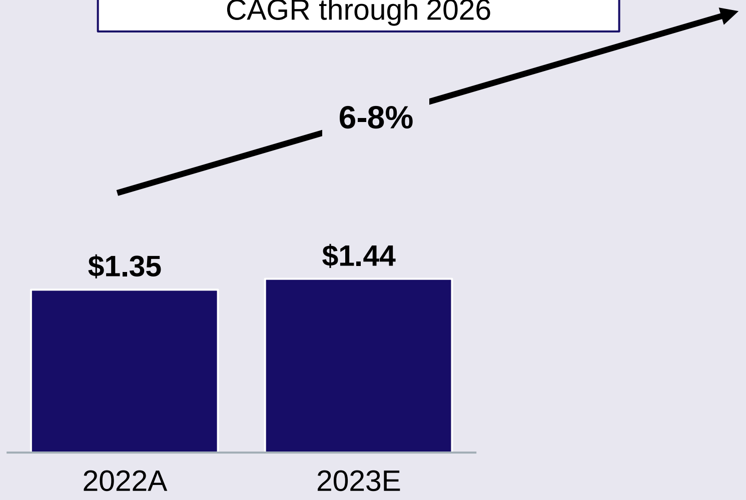
Long-Term Earnings Growth Supports Sustainable Dividend

Targeting 6-8% Operating Earnings* CAGR from 2022 - 2026(1)(5)



Projected Dividend Payout(4)

Expect ~60% dividend payout ratio resulting in dividend growing in-line with targeted **6-8%** operating EPS* CAGR through 2026



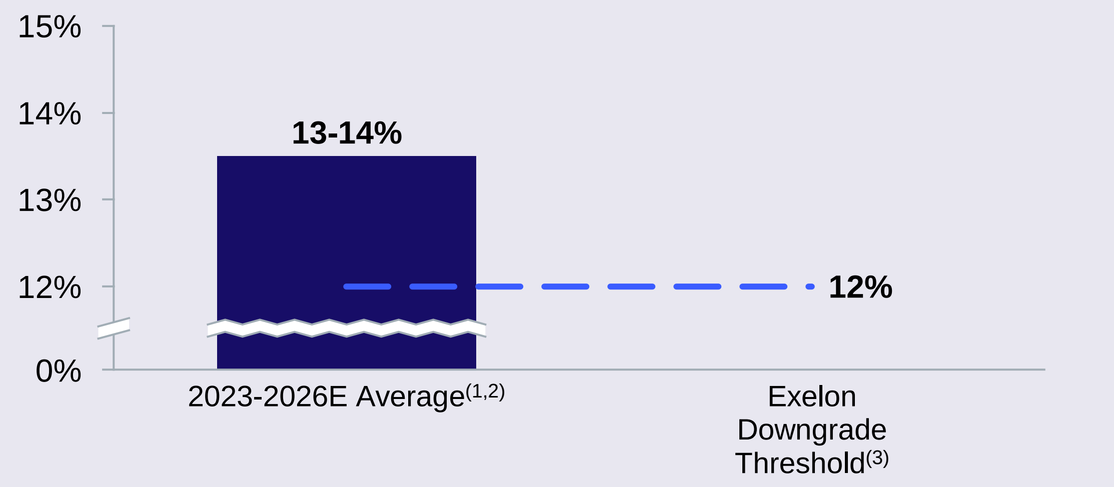
- Reaffirm prior target of 6-8% operating EPS* CAGR from 2021-2025(6), with expectation to be at **midpoint or better**
- Current target of 6-8% operating EPS* CAGR from 2022-2026(5), with expectation to be at **midpoint or better**
- Annual growth in 2024 and beyond projected to be within the 6-8% range, if not above it; slide 23 provides year-over-year growth drivers

Exelon is targeting operating EPS* CAGR of 6-8% from 2022 to 2026, and projecting a ~60% dividend payout ratio of operating earnings* that will grow in-line with the targeted 6-8% EPS* growth

Note: amounts may not sum due to rounding
(1) Includes after-tax interest expense associated with debt held at Corporate.
(2) Reflects 2022 original earnings guidance based on expected average outstanding shares of 983M. ComEd's 2022E original earnings guidance was based on a forward 30-year Treasury yield as of 12/31/2021.
(3) 2023E revised earnings guidance as disclosed on 3Q23 earnings call. 2023 revised earnings guidance based on expected average outstanding shares of 997M. ComEd's 2023E earnings guidance is based on a forward 30-year Treasury yield as of 9/30/2023.
(4) Dividend is subject to approval by the Board of Directors.
(5) Based off the midpoint of Exelon's 2022 Adjusted EPS* guidance range of $2.18 - $2.32 as disclosed at Analyst Day in January 2022.
(6) Based off the midpoint of Exelon's 2021 Adjusted EPS* guidance range of $2.06 - $2.14 as disclosed at Analyst Day in January 2022.

Maintaining a Strong Balance Sheet is a Top Financial Priority

S&P FFO / Debt %* and Moody's CFO (Pre-WC) / Debt %*



Low-risk Attributes Support a Strong Credit Profile

- Pure-play T&D utility company operating across 7 different regulatory jurisdictions
- Largest T&D utility in the country, serving 10+ million customers
- Track record of top quartile reliability performance
- Geographically diverse group of utilities in supportive regulatory jurisdictions
- ~100% of rate base growth covered by alternative recovery mechanisms and ~73% decoupled from volumetric risk

Credit Ratings[4]	ExCorp	ComEd	PECO	BGE	ACE	DPL	Pepco
Moody's	Baa2	A1	Aa3	A3	A2	A2	A2
S&P	BBB	A	A	A	A	A	A
Fitch	BBB	A	A+	A	A	A	A

Strong balance sheet and low-risk attributes provide strategic and financial flexibility

(1) 2023–2026 average internal estimate based on S&P and Moody's methodology, respectively.
(2) Without tax repairs deduction, CAMT cash impact expected to result in 2023–2026 average at the low end of range; with tax repairs deduction, CAMT cash impact expected to result in 2023–2026 average at the high end of range.
(3) S&P and Moody's downgrade thresholds based on their published reports for Exelon Corp.
(4) Current senior unsecured ratings for Exelon and BGE and current senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco.

Appendix

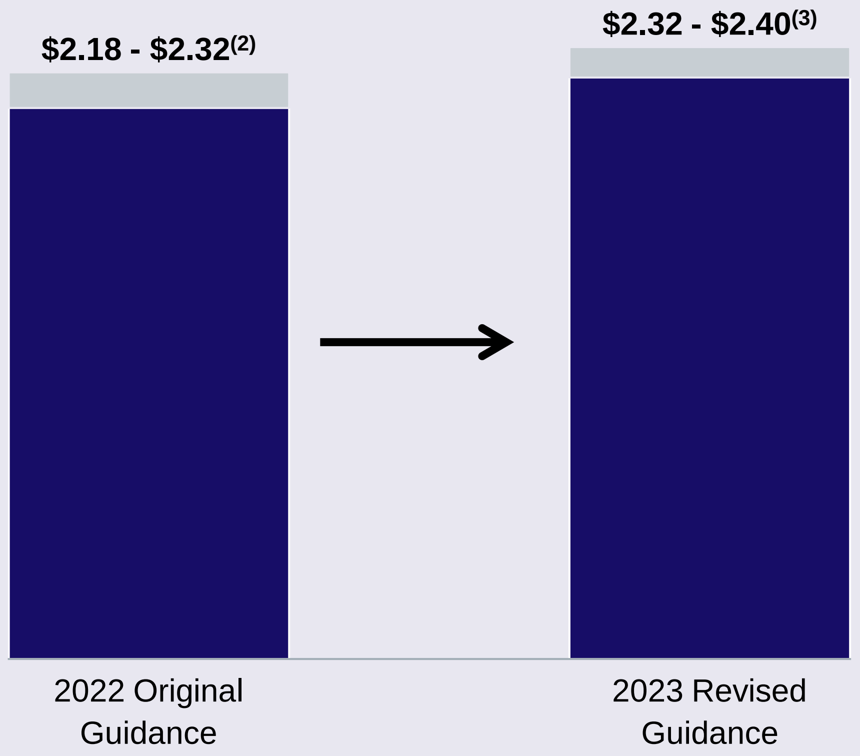
2023 Business Priorities and Commitments

- ❖ Maintain **industry-leading operational excellence**
- ❖ Achieve **constructive rate case outcomes** for customers and shareholders
- ❖ Deploy **$7.2B of capex** for the benefit of the customer
- ❖ Earn consolidated **operating ROE* of 9-10%**
- ❖ Deliver against **revised operating EPS* guidance of $2.32 - $2.40** per share
- ❖ Maintain **strong balance sheet** and execute on 2023 financing plan
- ❖ Continue to advocate for **equitable and balanced energy transition**
- ❖ Focus on **customer affordability**, including through **cost management**

Focused on continued execution of operational, regulatory, and financial priorities to build on the strength of Exelon's value proposition as the premier T&D utility

2023 Adjusted Operating Earnings* Guidance

Adjusted Operating Earnings* Guidance[1]



Key Year-over-Year Drivers

- ⬆ Incremental investments in utility infrastructure
- ⬆ Discontinued operations adjustment not applicable in post-separation results
- ⬇ BGE and PHI MYP 1 reconciliation in process
- ⬇ Return to normal storm activity and weather
- ⬇ Incremental debt at Corporate and other financing costs

2023 operating EPS* growth of ~5% from 2022 guidance midpoint to 2023 guidance midpoint

(1) Includes after-tax interest expense associated with debt held at Corporate
(2) 2022 earnings guidance based on expected average outstanding shares of 983M. ComEd's 2022E earnings guidance was based on a forward 30-year Treasury yield as of 12/31/2021.
(3) 2023E revised earnings guidance as disclosed on 3Q23 earnings call. 2023 revised earnings guidance based on expected average outstanding shares of 997M. ComEd's 2023E earnings guidance is based on a forward 30-year Treasury yield as of 9/30/2023.

Key Modeling Drivers and Assumptions

	2023		2024		2025		2026	
OpCo	**Drivers[1]**	**YoY EPS**	**Drivers[1]**	**YoY EPS**	**Drivers[1]**	**YoY EPS**	**Drivers[1]**	**YoY EPS**
BGE	Gas and electric MYP 1 year 3 rates, MYP 1 reconciliation (2021 and 2022), and transmission, offset by MYP 1 regulatory lag	↑	Gas and electric MYP 2 year 1 rates, MYP 1 reconciliation (2023), and transmission	↑	Gas and electric MYP 2 year 2 rates and transmission	↑	Gas and electric MYP 2 year 3 rates and transmission	↑
ComEd	Distribution and transmission rate base growth; 30-Yr TSY on ROE	↑	Distribution and transmission rate base growth (MYP 1 year 1 rates)	↑	Distribution and transmission rate base growth (MYP 1 year 2 rates)	↑	Distribution and transmission rate base growth (MYP 1 year 3 rates)	↑
PECO	Return to normal weather and storm, electric year 2 in 3-yr cadence of FPFTY, partially offset by year 1 gas rates, transmission, and electric DSIC tracker[2]	↓	Electric year 3 and gas year 2 in 3-yr cadence of FPFTY, offset by transmission and DSIC tracker[2]	→	Year 1 electric rates, transmission, and gas DSIC tracker, partially offset by gas year 3 in 3-yr cadence of FPFTY[2]	↑	Electric year 2 in 3-yr cadence of FPFTY, partially offset by year 1 gas rates, transmission, and electric DSIC tracker[2]	→
PHI	Pepco MD MYP 1 year 3, DPL MD MYP 1 year 1, DPL DE gas and electric rates, and transmission, partially offset by Pepco DC MYP 1 stay out regulatory lag	↑	Pepco DC and MD MYP 2 year 1, DPL MD MYP 1 year 2 rates, and transmission	↑	Pepco DC and MD MYP 2 year 2, DPL MD MYP 1 year 3 rates, and transmission	↑	Pepco DC and MD MYP 2 year 3, DPL MD MYP 2 year 1 rates, and transmission	↑
Corp	$1.65B of new debt and other financing costs, partially offset by the absence of disc. ops adj.	↓	Portion of $3.4B of 2024-2026 new debt and other financing costs	↓	Portion of $3.4B of 2024-2026 new debt and other financing costs	↓	Portion of $3.4B of 2024-2026 new debt and other financing costs	↓
Total YoY Growth Relative to Range	**Growth Below Low End of 6-8% Range**		**Growth in Low End of 6-8% Range**		**Growth Above 6-8% Range**		**Growth in Middle of 6-8% Range**	

Rate case activity and investment plan drives annual growth path towards expectation of being at midpoint or better of expected 6-8% operating EPS* CAGRs[3] for 2021 - 2025 and 2022 - 2026

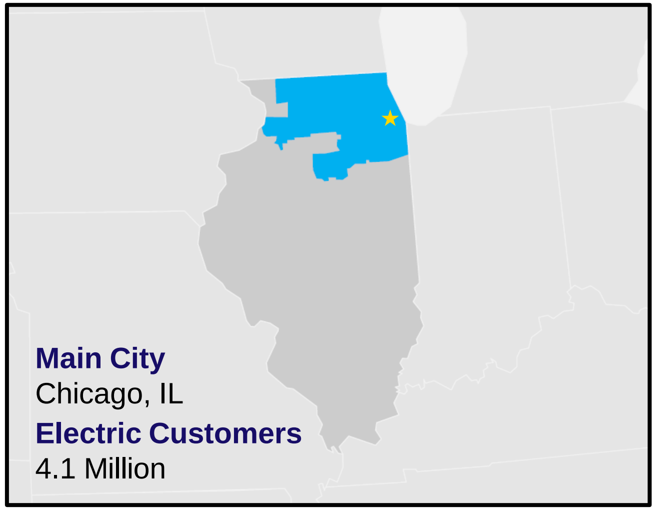
Note: YoY earnings growth estimates are for illustrative purposes only to provide indicative YoY variability; arrows indicate incremental contribution or drag to YoY operating EPS* growth but not necessarily equivalent in terms of relative impact

(1) Reflects publicly known distribution rate cases that Exelon has filed or expects to file in 2023. Excludes traditional base rate cases with filing dates that are not yet available to the public. Known and measurable drivers as of 4Q22 earnings call.

(2) PECO assumes a 3-year rate case cadence of Fully Projected Future Test Year (FPFTY) for long-range planning purposes; i.e., filing in 2024 and 2025 for electric and gas distribution, respectively.

(3) 2021-2025 and 2022-2026 EPS CAGRs based off the midpoints of Exelon's 2021 Adjusted EPS* guidance range of $2.06 - $2.14 and Exelon's 2022 Adjusted EPS* guidance range of $2.18 - $2.32 as disclosed at 2022 Analyst Day, respectively.

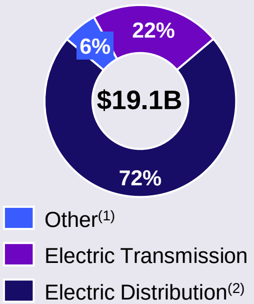
ComEd Overview



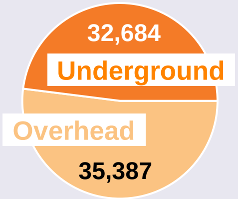
Main City
Chicago, IL
Electric Customers
4.1 Million

Territory Overview

2022 Rate Base
37% of Total Exelon



Circuit Miles



Key State Policies & Goals

Climate & Equitable Jobs Act (CEJA)

Transition to Clean Energy
Path to 100% clean energy by 2045 & enables ComEd load to be supplied by clean generation by 2026

Decarbonization through Energy Efficiency and Beneficial Electrification
Accelerates the adoption and uptake of EVs and other technologies

Community Support Transition
Expands low-income renewable energy funding and increases energy assistance

Equitable Workforce Development

$180M
Annual energy transition funds

1M
EVs expected by 2030

$130M
Energy transition training/mentoring

Rate Recovery Overview

Distribution

- 2023 electric rates based on distribution formula rate plan with an allowed ROE set to the 30-year UST rate + 580 bps(3)
- Filed a four-year multi-year plan (MYP) in January 2023 with an order expected in December 2023
  - Includes a phase-in of new rates, deferring 35% of the first year's bill impact until 2026
  - Includes ability to earn +/- 32 bps across 7 performance metrics
- Decoupled
- Major Storm Deferral

Transmission

Annual formula rate filing for electric transmission rates set by FERC and based on 11.50% allowed ROE

Trackers

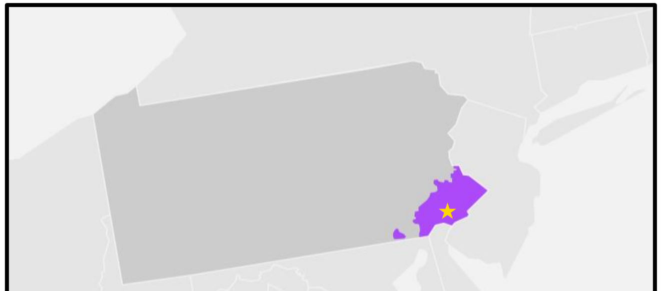
Future Energy Jobs Act (FEJA)
Permits recovery of energy efficiency programs and distributed generation rebates

Bad Debt Tracker

Note: reflects most recent available data as of August 14, 2023; Territory Overview reflects data as of 2022 10-K
(1) Other includes long-term regulatory assets, which generally earn a return consistent with rate base, including Energy Efficiency and the Solar Rebate Program.
(2) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.
(3) ComEd filed its 2022 reconciliation under its transition tariff (Rider DSPR) seeking recovery for rates effective on January 1, 2024, and an order is expected in December 2023. ComEd will also file to reconcile 2023 rates in 2024.

exelon

PECO Overview



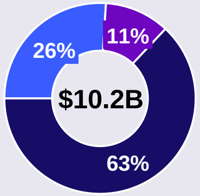
Main City
Philadelphia, PA

Electric Customers
1.7 Million

Gas Customers
0.5 Million

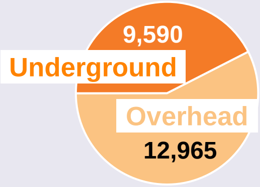
Territory Overview

2022 Rate Base
20% of Total Exelon

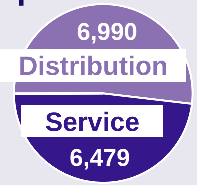


Gas Delivery
Electric Transmission
Electric Distribution(1)

Circuit Miles



Pipeline Miles(2)



Key State Policies & Goals

Alternative Energy Portfolio Standards
Requirement that a percentage of electricity sold each year comes from alternative energy sources (8% traditional renewables with 0.5% from solar)

Energy Efficiency Programs
Mandated energy efficiency programs with spending capped at ~$85M/year

Distribution System & Infrastructure Investment
Distribution System Improvement Charge (DSIC) and alternative ratemaking legislation support certainty and flexibility in cost recovery

Transportation Electrification
Non-binding state goal of 30% of new medium- and heavy-duty truck sales by 2030 and 100% by 2050. Legislation providing utility cost recovery for TE programs under consideration

Rate Recovery Overview

Distribution

- Electric and gas rates based on fully projected future test year. Rates went into effect in 2022 and 2023, respectively
- Volumetric Revenue

Transmission

Annual formula rate filing for electric transmission rates set by FERC and based on 10.35% allowed ROE

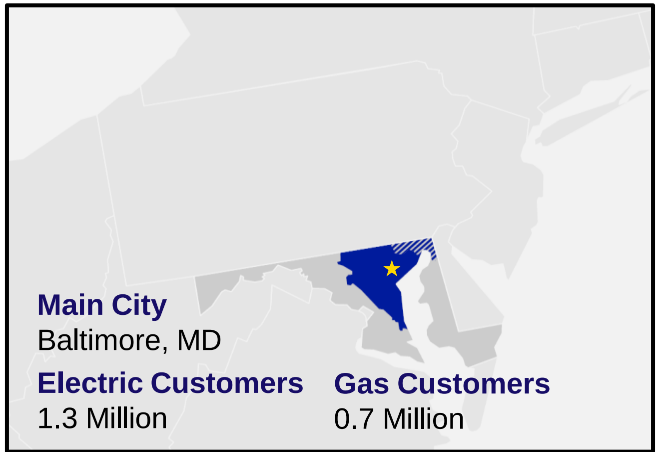
Trackers

Distribution System Improvement Charge (DSIC)
Provides recovery for Long-Term Infrastructure Improvement Plan (LTIIP) for electric and gas distribution in between rate cases

Energy Efficiency and Demand Response Programs
Act 129 Energy Efficiency program allows for full recovery of O&M costs under a 1307 rider mechanism

Note: reflects most recent available data as of August 14, 2023; Territory Overview reflects data as of 2022 10-K
(1) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.
(2) PECO pipeline miles also includes 9 miles of transmission.

BGE Overview



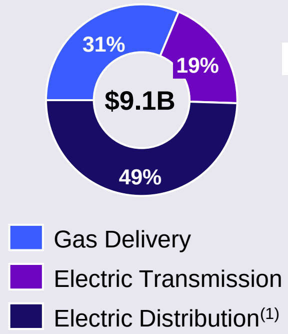
Main City
Baltimore, MD

Electric Customers
1.3 Million

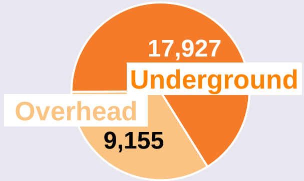
Gas Customers
0.7 Million

Territory Overview

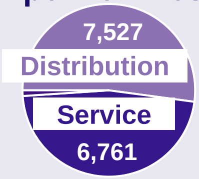
2022 Rate Base
18% of Total Exelon



Circuit Miles



Pipeline Miles[2]



Key State Policies & Goals

Climate Solutions Now Act (CSNA)

Targets 60% reduction in greenhouse gas emissions by 2031 and net-zero greenhouse gas emissions by 2045

Building Decarbonization & Electrification

Energy Efficiency and Demand Response

Transportation Electrification

Promoting Offshore Wind Energy Resource Act (POWER)

8.5 gigawatts of power from offshore wind by 2031

Rate Recovery Overview

Distribution

- 2023 electric and gas rates reflect a three-year cumulative multi-year plan (MYP) for 2021 to 2023 with allowed ROEs of 9.50% and 9.65%, respectively
- Filed second three-year electric and gas MYPs in February 2023 with rates expected to go into effect in 2024. The proceedings will also reconcile the first two years of BGE's first MYP
- Decoupled
- Major Storm Deferral

Transmission

Annual formula rate filing for electric transmission rates set by FERC and based on 10.50% allowed ROE

Trackers

Strategic Infrastructure Development and Enhancement (STRIDE)[3]

Recovery of accelerated replacement of aging gas infrastructure

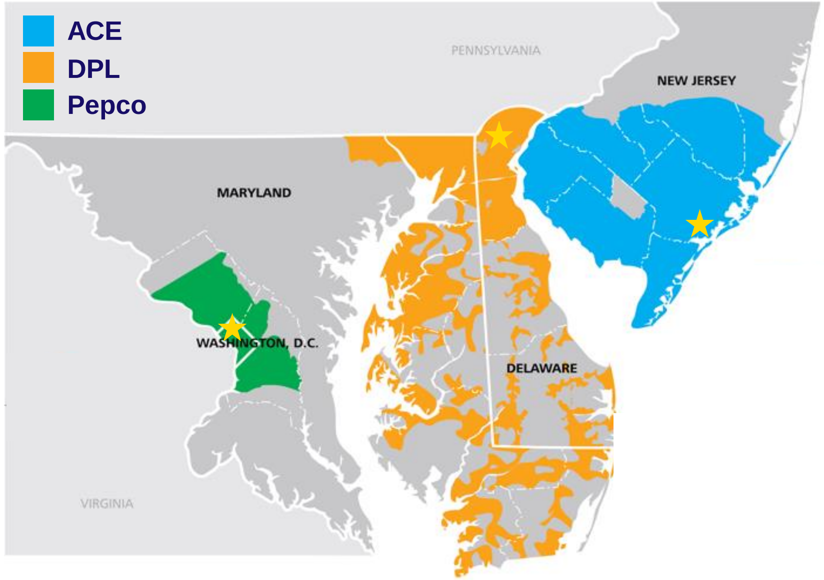
EmPOWER MD[4]

Recovery on energy efficiency and demand response programs

Note: reflects most recent available data as of August 14, 2023; Territory Overview reflects data as of 2022 10-K

(1) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.
(2) BGE pipeline miles also includes 152 miles of transmission.
(3) BGE has proposed to include aging gas infrastructure replacement work, currently recovered under the STRIDE program, in MYP base rates beginning in 2024.
(4) The MD PSC issued an order outlining the plans to phase out and retire EmPOWER regulatory assets. All MD utilities will be required to expense 33% of program costs in 2024, 67% in 2025, and 100% in 2026 and beyond.

PHI Overview



Territory Overview

ACE

Main City	Electric Customers
Atlantic City, NJ	0.6 Million

DPL

Main City	Electric Customers
Wilmington, DE	0.5 Million
	Gas Customers
	0.1 Million

Pepco[2]

Main City	Electric Customers
Washington D.C.	0.9 Million

Key District/State Policies & Goals

D.C. Climate Commitment Act

Promotes a wide range of policies that support the DC Climate Action Plan, including carbon neutrality by 2045

Delaware Climate Change Solutions Act

Targets 50% reduction in greenhouse gas emissions by 2030 and net-zero by 2050

MD Climate Solutions Now Act (CSNA)

Targets 60% reduction in greenhouse gas emissions by 2031 and net-zero by 2045

Renewable Energy Mix

DC – 100% by 2032
DE – 40% by 2035
MD – 50% by 2030; net-zero by 2045
NJ – 100% by 2035 & 11 GW of offshore wind

Transportation Electrification

DC – 50% by 2030; 100% by 2035
DE – 17,000 EVs sold annually by 2030
MD – 100% passenger sales by 2035
NJ – 100% passenger sales by 2035

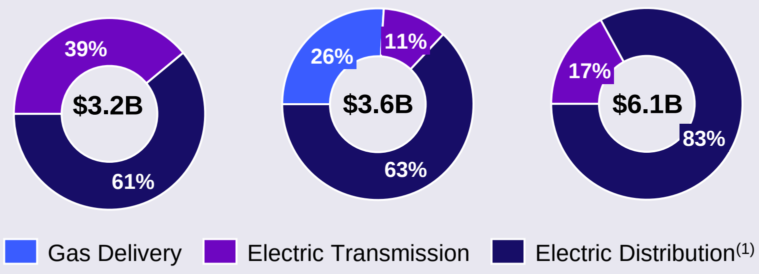
Building Energy Performance Standards

DC requires a net zero energy building code for all new commercial buildings

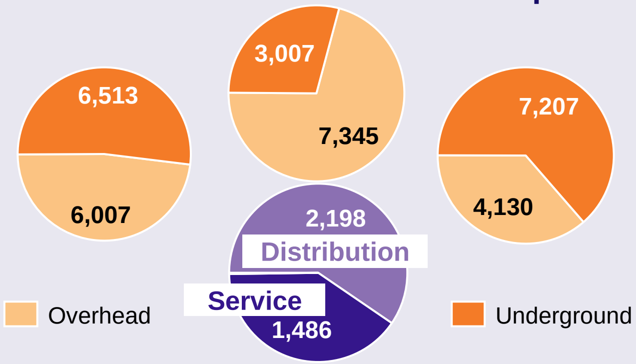
Workforce Development Programs

2022 Rate Base

ACE	DPL	Pepco
6% of Total Exelon	7% of Total Exelon	12% of Total Exelon



Circuit & Pipeline[3] Miles



Note: reflects most recent available data as of August 14, 2023; Territory Overview reflects data as of 2022 10-K

(1) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.
(2) Pepco's jurisdiction covers both the District of Columbia and Maryland.
(3) DPL pipeline miles also includes 8 miles of transmission.

PHI Rate Recovery Overview

Pepco MD

Distribution

- 2023 electric rates reflect a three-year cumulative multi-year plan (MYP) for April 1, 2021 to March 31, 2024 with an allowed ROE of 9.55%
- Filed second three-year electric MYP with proposed 9-month extension(1) in May 2023 with rates expected to go into effect in Q2 2024. The proceedings will also reconcile the first two years of Pepco's first MYP
- Decoupled
- Major Storm Deferral

Transmission

Annual formula rate filing for electric transmission rates set by FERC and based on 10.50% allowed ROE

Trackers

EmPOWER MD(2)

Recovery on energy efficiency and demand response programs

Pepco DC

Distribution

- 2023 electric rates reflect a three-year cumulative multi-year plan (MYP) for July 1, 2021 to December 31, 2022 with an allowed ROE of 9.275%
- Filed second three-year electric MYP in April 2023. Company proposed rates effective February 15, 2024, January 1, 2025, and January 1, 2026
- Decoupled
- Major Storm Deferral

Transmission

Annual formula rate filing for electric transmission rates set by FERC and based on 10.50% allowed ROE

Trackers

DC Power Line Undergrounding (DC PLUG)

Provides for contemporaneous recovery of reliability and resiliency investments to underground the most vulnerable feeders

DPL MD

Distribution

- 2023 electric rates reflect a three-year cumulative multi-year plan (MYP) for 2023 to 2026 with an allowed ROE of 9.60%
- Decoupled
- Major Storm Deferral

Transmission

Annual formula rate filing for electric transmission rates set by FERC and based on 10.50% allowed ROE

Trackers

EmPOWER MD(2)

Recovery on energy efficiency and demand response programs

DPL DE

Distribution

- 2023 electric and gas rates based on partially projected future test year with rates in effect in 2020 and 2022, respectively, and allowed ROEs of 9.60%
- Filed application in December 2022 seeking an increase in electric base rates. An order is expected in Q2 2024 with interim rates going into effect July 2023
- Volumetric Revenue

Transmission

Annual formula rate filing for electric transmission rates set by FERC and based on 10.50% allowed ROE

Trackers

Distribution System Improvement Charge (DSIC)

Provides a mechanism to begin recovering gas and electric infrastructure investments for reliability every six months

ACE

Distribution

- 2023 electric rates based on partially projected future test year with rates in effect in 2022 and an allowed ROE of 9.60%
- Filed application in February 2023 seeking an increase in electric base rates. An order is expected in Q1 2024
- Decoupled
- Major Storm Deferral

Transmission

Annual formula rate filing for electric transmission rates set by FERC and based on 10.50% allowed ROE

Trackers

Energy Efficiency Program

Bad Debt

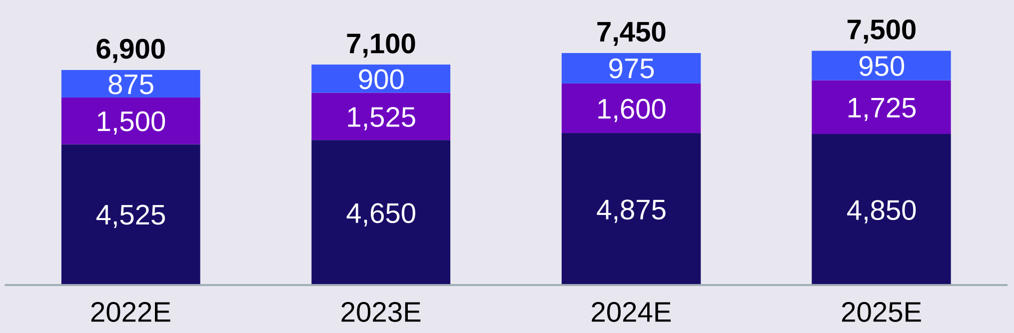
Infrastructure Investment Program (IIP)

Recovery of certain capital investments, primarily related to safety and reliability

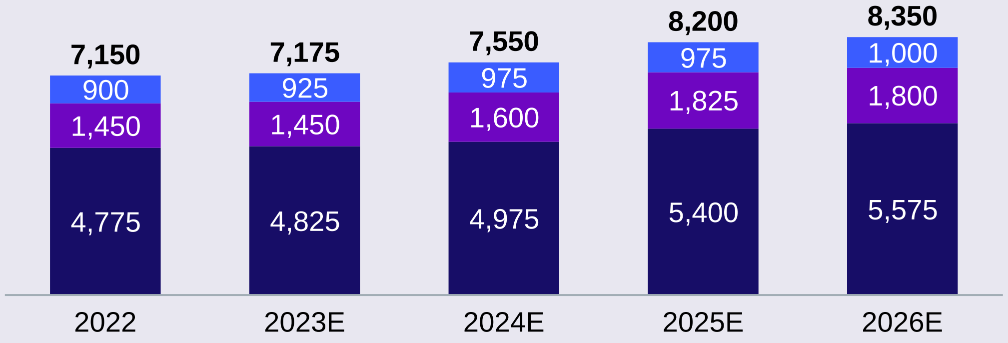
(1) Pepco is proposing to extend this MYP through December 31, 2027 in order to position utilities currently operating under MYPs to file future applications on staggered schedules and avoid over-burdening Commission Staff and other parties.
(2) The MD PSC issued an order outlining the plans to phase out and retire EmPOWER regulatory assets. All MD utilities will be required to expense 33% of program O&M costs in 2024, 67% in 2025, and 100% in 2026 and beyond.

Utility Capex and Rate Base vs. Previous Disclosures

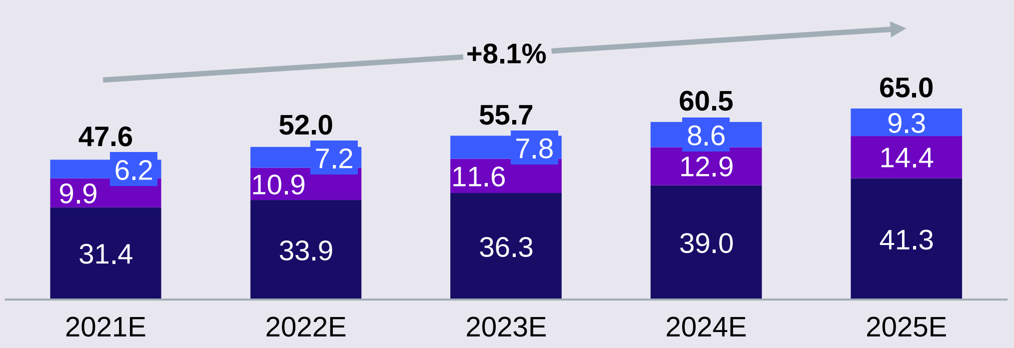
Analyst Day 2022 Capital Expenditures ($M)



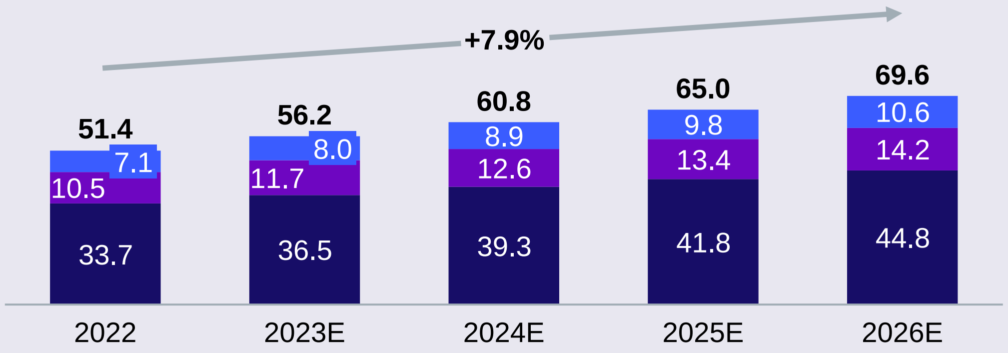
Q4 2022 Capital Expenditures ($M)



Analyst Day 2022 Rate Base ($B)



Q4 2022 Rate Base ($B)



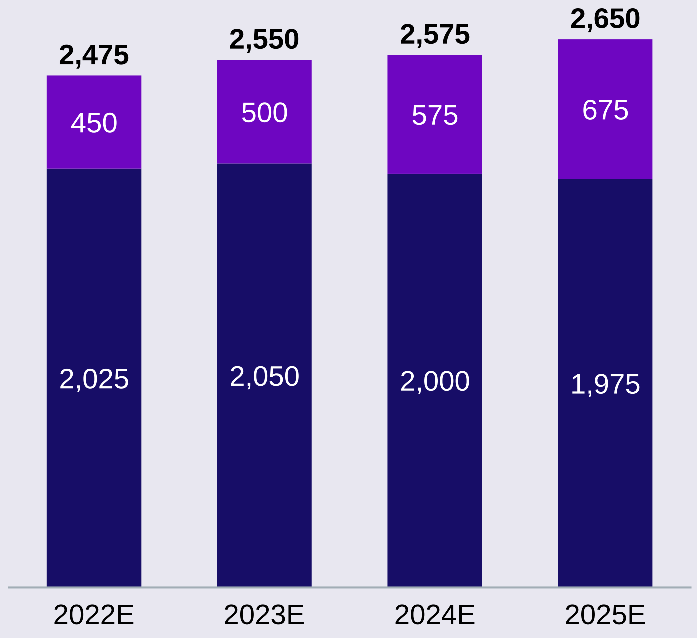
Gas Delivery/Other[(1)] Electric Transmission Electric Distribution[(2)]

Planning to invest $31.3B of capital from 2023-2026 for the benefit of our customers, supporting projected rate base growth of 7.9% from 2022-2026

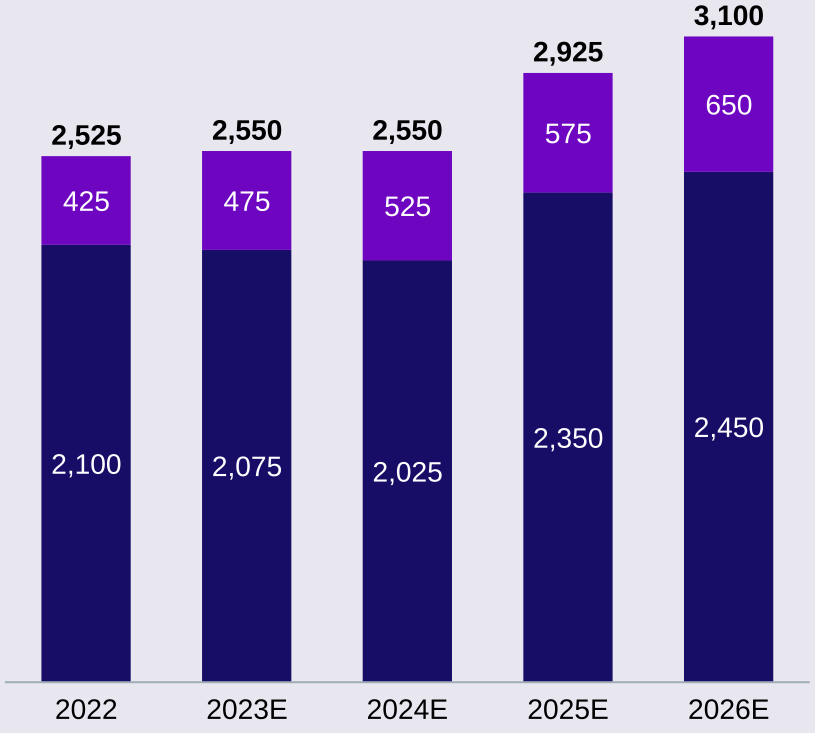
Note: Numbers rounded to nearest $25M and may not sum due to rounding. Rate base reflects year-end estimates. Analyst Day 2022 capex disclosures dated January 10, 2022. Q4 2022 disclosures dated February 14, 2023.
(1) Other includes long-term regulatory assets, which generally earn a return consistent with rate base, including Energy Efficiency and the Solar Rebate Program.
(2) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.

ComEd Capital Expenditure Forecast

Analyst Day 2022 Capital Expenditures ($M)

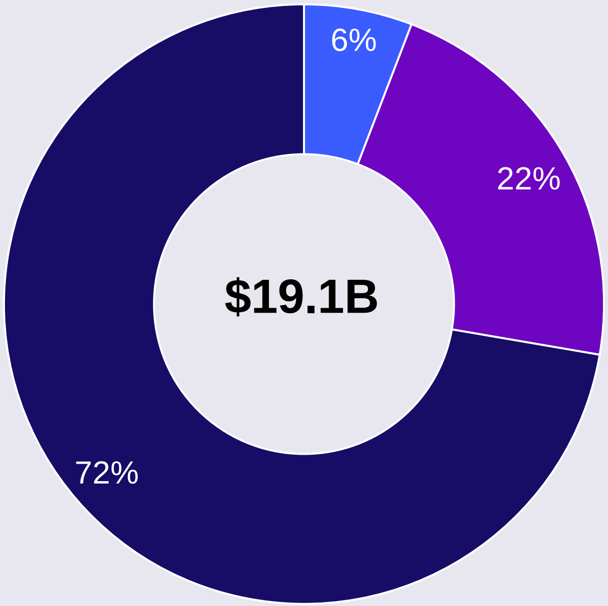


Q4 2022 Capital Expenditures ($M)



Rate Base

2022: 37% of Total Exelon Rate Base



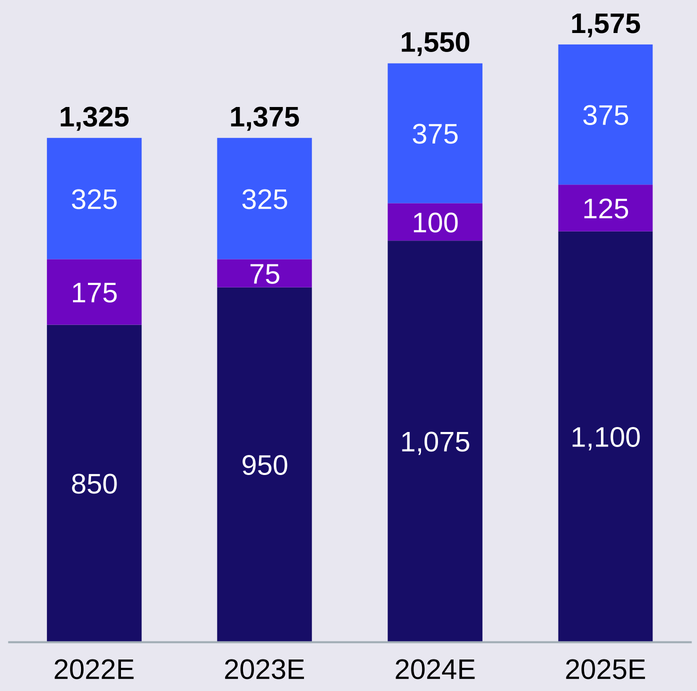
Gas Delivery/Other(1) Electric Transmission Electric Distribution(2)

Project ~$11.1B of capital being invested from 2023-2026

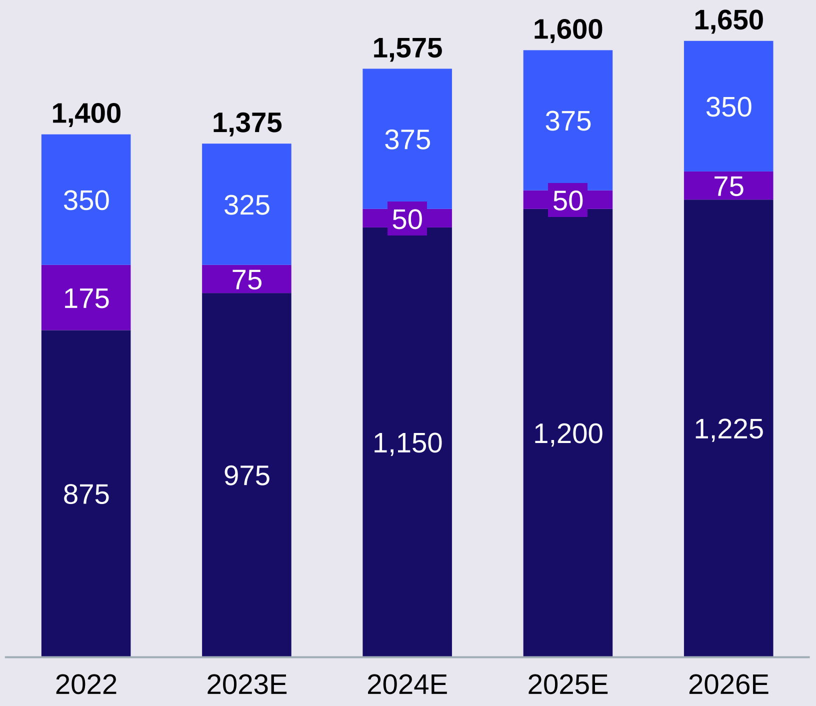
Note: Numbers rounded to nearest $25M and may not sum due to rounding. Rate base reflects year-end estimates. Analyst Day 2022 capex disclosures dated January 10, 2022. Q4 2022 disclosures dated February 14, 2023.
(1) Other includes long-term regulatory assets, which generally earn a return consistent with rate base, including Energy Efficiency and the Solar Rebate Program.
(2) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.

PECO Capital Expenditure Forecast

Analyst Day 2022 Capital Expenditures ($M)

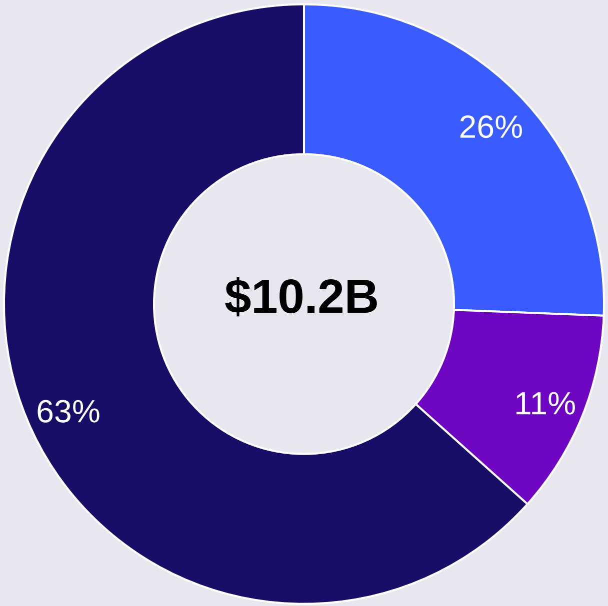


Q4 2022 Capital Expenditures ($M)



Rate Base

2022: 20% of Total Exelon Rate Base



Gas Delivery/Other   Electric Transmission   Electric Distribution[(1)]

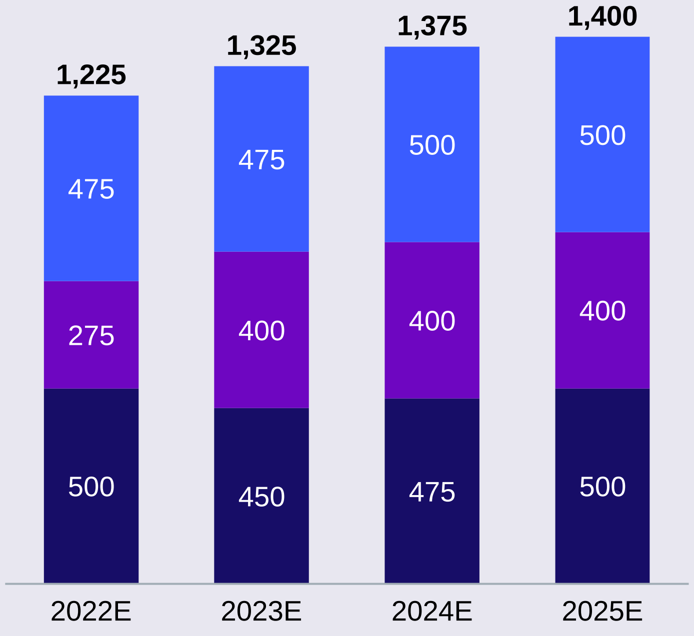
Project ~$6.2B of capital being invested from 2023-2026

Note: Numbers rounded to nearest $25M and may not sum due to rounding. Rate base reflects year-end estimates. Analyst Day 2022 capex disclosures dated January 10, 2022. Q4 2022 disclosures dated February 14, 2023.

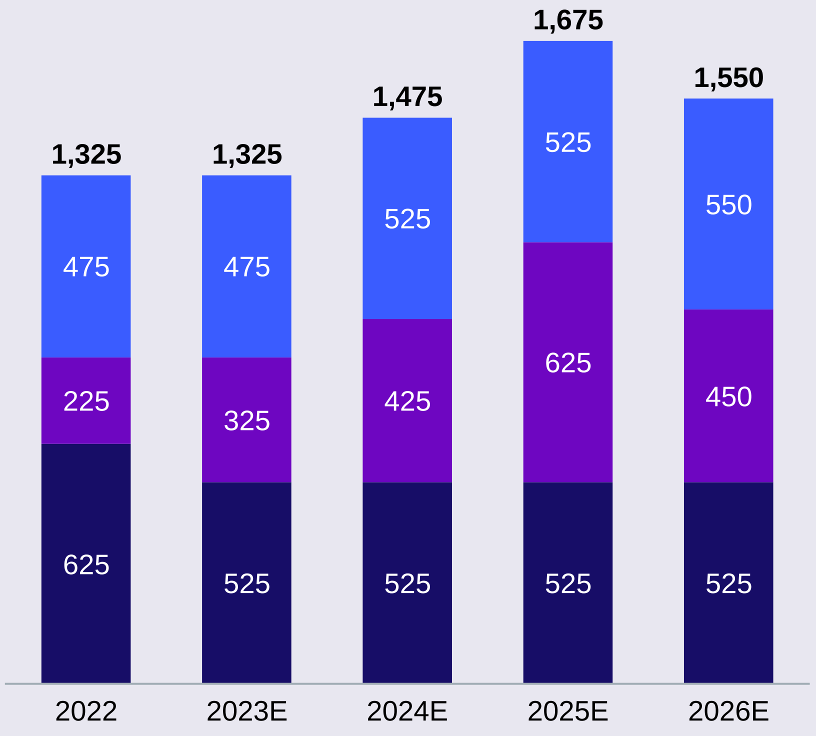
(1) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.

BGE Capital Expenditure Forecast

Analyst Day 2022 Capital Expenditures ($M)

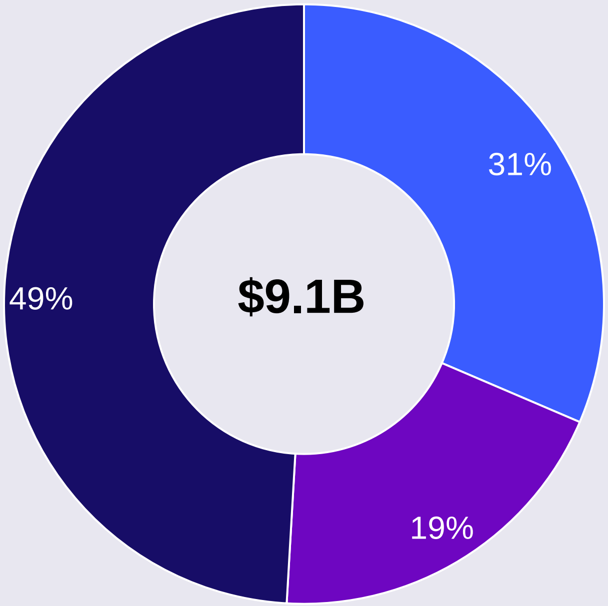


Q4 2022 Capital Expenditures ($M)



Rate Base

2022: 18% of Total Exelon Rate Base



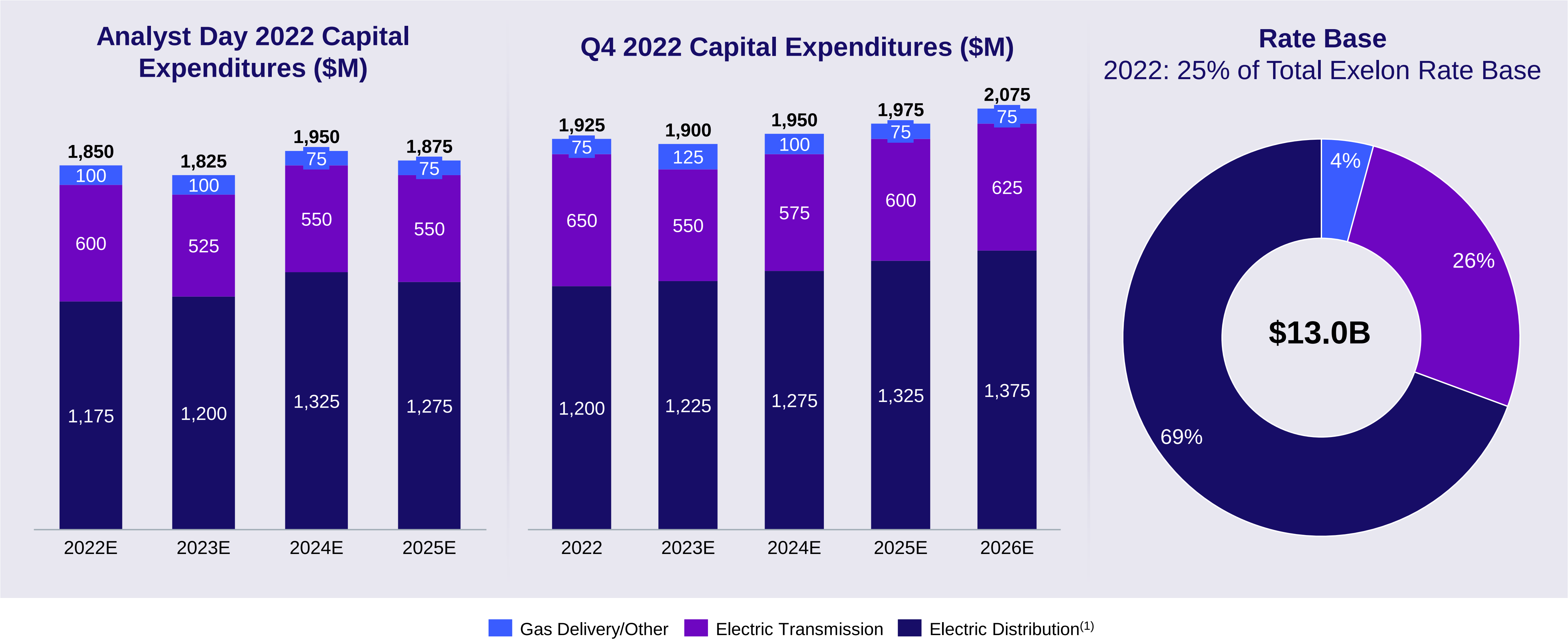
Gas Delivery/Other Electric Transmission Electric Distribution(1)

Project ~$6.0B of capital being invested from 2023-2026

Note: Numbers rounded to nearest $25M and may not sum due to rounding. Rate base reflects year-end estimates. Analyst Day 2022 capex disclosures dated January 10, 2022. Q4 2022 disclosures dated February 14, 2023.
(1) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.

exelon

PHI Consolidated Capital Expenditure Forecast



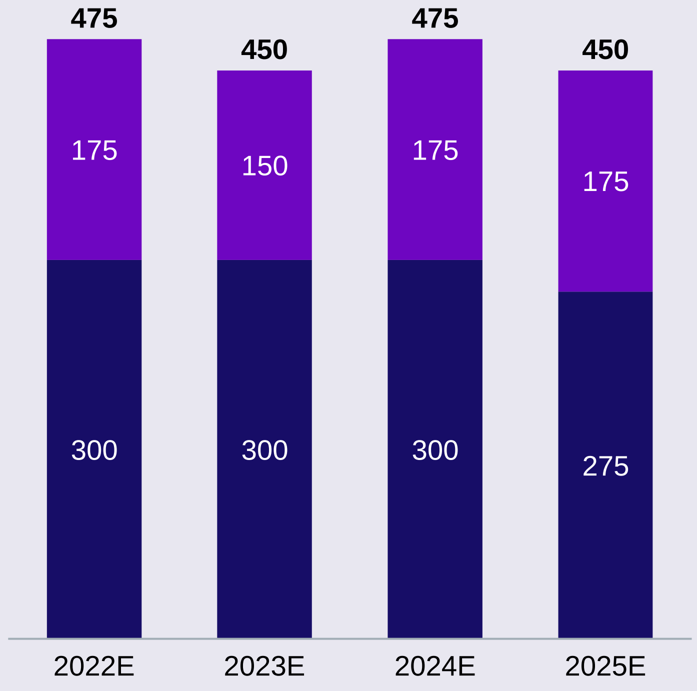
Project ~$7.9B of capital being invested from 2023-2026

Note: Numbers rounded to nearest $25M and may not sum due to rounding. Rate base reflects year-end estimates. Analyst Day 2022 capex disclosures dated January 10, 2022. Q4 2022 disclosures dated February 14, 2023.

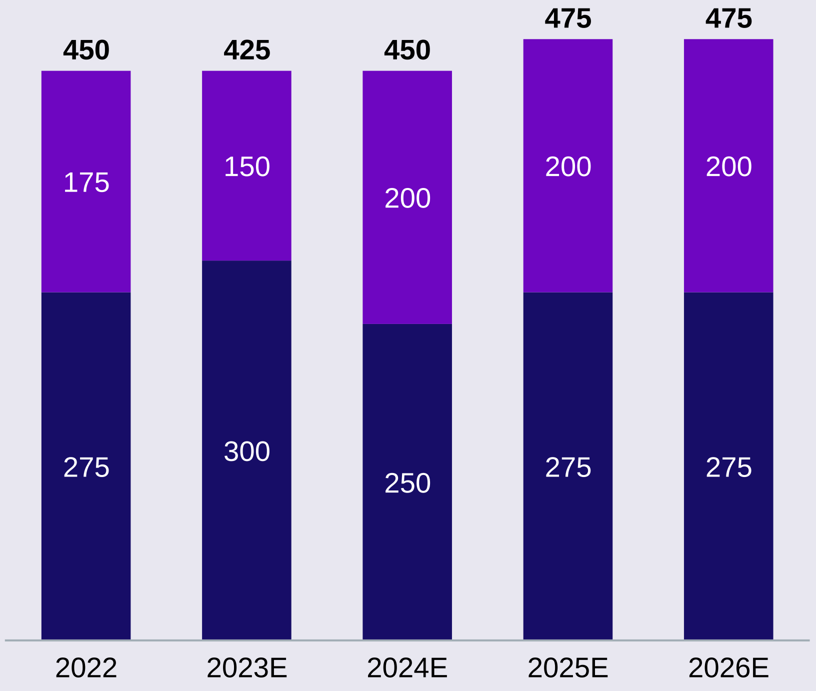
(1) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.

ACE Capital Expenditure Forecast

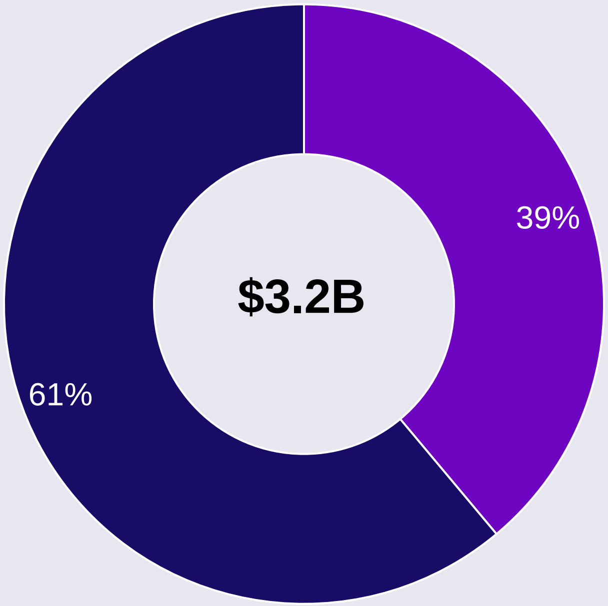
Analyst Day 2022 Capital Expenditures ($M)



Q4 2022 Capital Expenditures ($M)



Rate Base
2022: 6% of Total Exelon Rate Base



Electric Transmission   Electric Distribution[1]

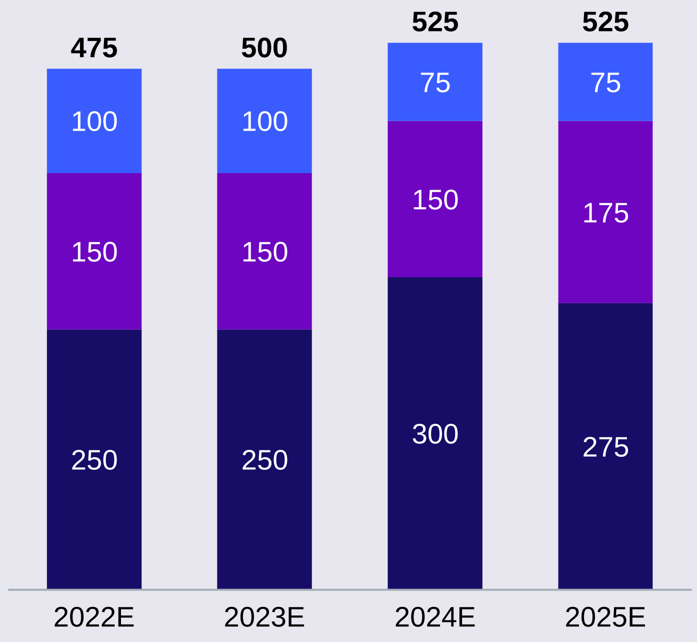
Project ~$1.8B of capital being invested from 2023-2026

Note: Numbers rounded to nearest $25M and may not sum due to rounding. Rate base reflects year-end estimates. Analyst Day 2022 capex disclosures dated January 10, 2022. Q4 2022 disclosures dated February 14, 2023.
(1) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.

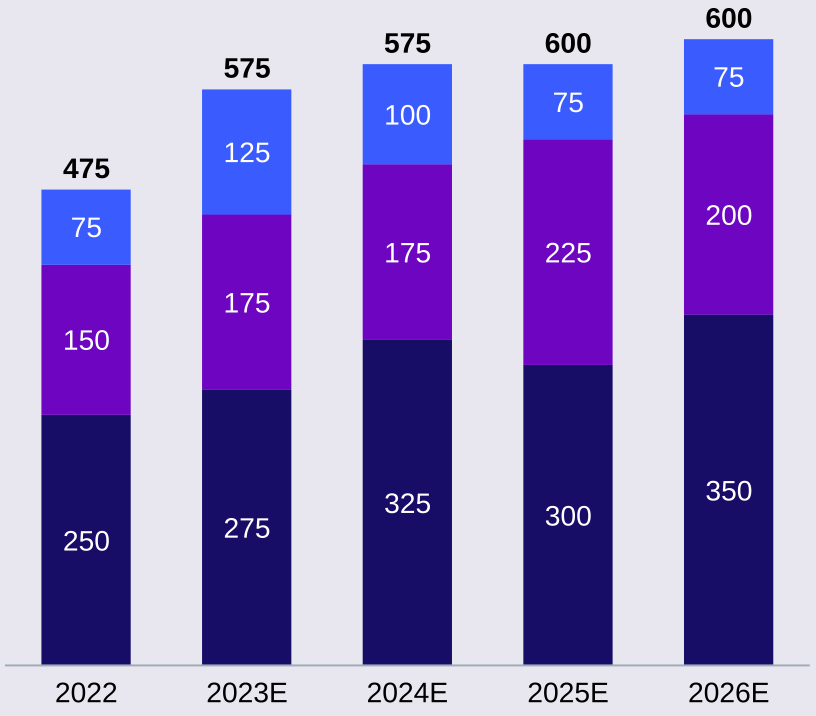
exelon

DPL Capital Expenditure Forecast

Analyst Day 2022 Capital Expenditures ($M)

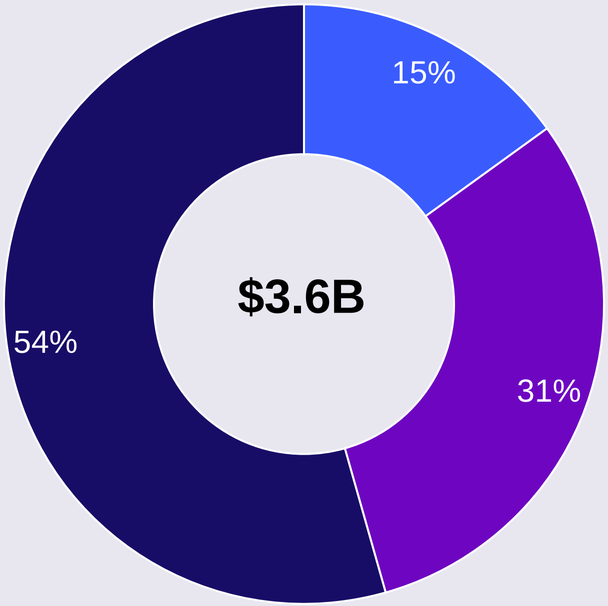


Q4 2022 Capital Expenditures ($M)



Rate Base

2022: 7% of Total Exelon Rate Base



Gas Delivery Electric Transmission Electric Distribution[1]

Project ~$2.4B of capital being invested from 2023-2026

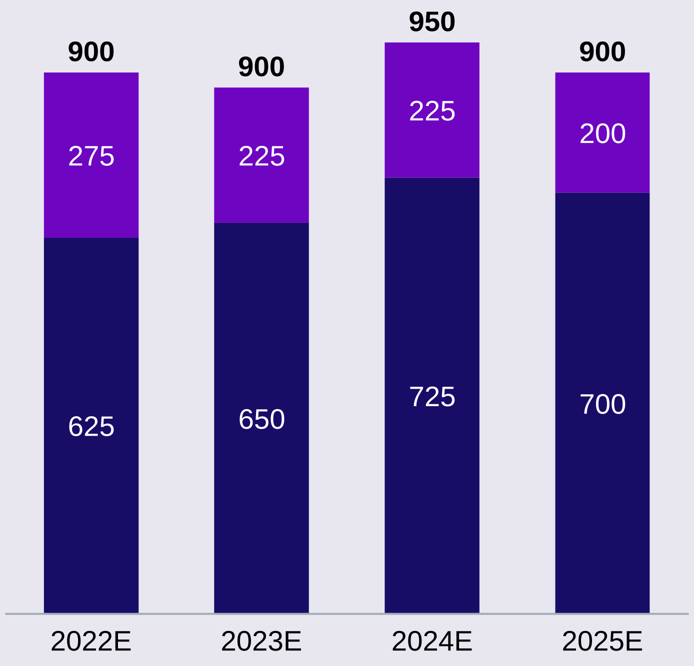
Note: Numbers rounded to nearest $25M and may not sum due to rounding. Rate base reflects year-end estimates. Analyst Day 2022 capex disclosures dated January 10, 2022. Q4 2022 disclosures dated February 14, 2023.

(1) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.

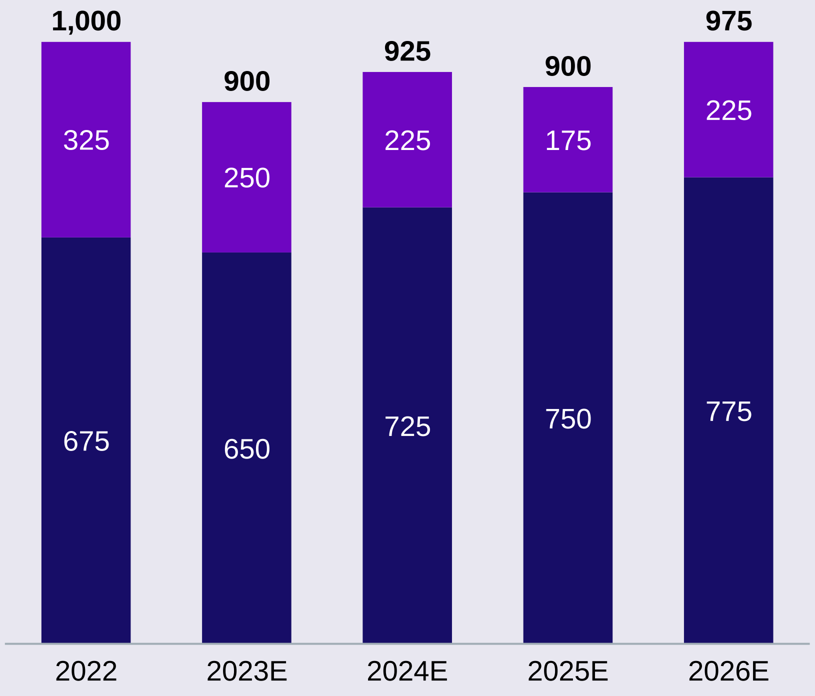
exelon

Pepco Capital Expenditure Forecast

Analyst Day 2022 Capital Expenditures ($M)

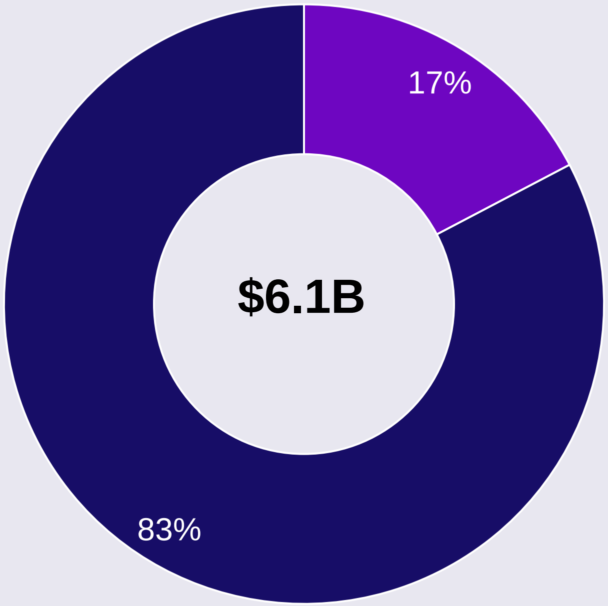


Q4 2022 Capital Expenditures ($M)



Rate Base

2022: 12% of Total Exelon Rate Base



Electric Transmission Electric Distribution(1)

Project ~$3.7B of capital being invested from 2023-2026

Note: Numbers rounded to nearest $25M and may not sum due to rounding. Rate base reflects year-end estimates. Analyst Day 2022 capex disclosures dated January 10, 2022. Q4 2022 disclosures dated February 14, 2023.

(1) Electric distribution rate base includes regulatory assets that earn a full authorized Rate of Return; regulatory asset spend not reflected in capital spend projections.

2023 Financing Plan[1]

OpCo	Instrument	Issuance ($M)	Maturity ($M)	Issued ($M)[3]	Remaining ($M)
comed AN EXELON COMPANY	FMB	$975	-	$975	-
pepco AN EXELON COMPANY	FMB	$350	-	$350	-
atlantic city electric AN EXELON COMPANY	FMB	$75	-	$75	-
delmarva power AN EXELON COMPANY	FMB	$650	($500)	$650	-
peco AN EXELON COMPANY	FMB	$525	($50)	$575	-
bge AN EXELON COMPANY	Senior Notes	$600	($300)	$700	-
exelon	Senior Notes	$2,500	($850)[2]	$2,500	-
	Equity	*$425M of equity expected between 2023 and 2025*	-	-	-

Capital plan financed with a balanced approach to maintain strong investment grade ratings

Note: FMB represents First Mortgage Bonds
(1) Financing plans are subject to change, depending on capital expenditures, regulatory outcomes, internal cash generation, market conditions, changes in tax policies, and other factors.
(2) Represents $850M of term loans repaid on March 14, 2023.
(3) Issued amounts as of September 30, 2023. Pepco, ACE, and DPL priced FMBs in the private placement market in February 2023. As of September 30, 2023, Pepco, ACE, and DPL funded $350M, $75M, and $125M, respectively. Using a delayed draw feature, DPL will fund $525M in November 2023.

2023-2026 Financing Plan

Balanced investment and value return strategy results in limited equity needs over the next several years

Note: Financing plan is subject to change
(1) Adjusted Cash from Operations* is net of common dividends and change in cash on hand.
(2) Includes both utility and corporate debt. Anticipate maintaining ~51% equity to capital ratio at the utilities. Of the $13B, corporate debt issuances expected to be approximately $5 billion over 2023-2026.
(3) Expect to issue the remaining $425 million of equity between 2023 and 2025.

Exelon Distribution Rate Case Updates

	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
DPL DE Electric		IT	RT			EH				FO	FO	FO	
ComEd[3]		EH	IB RB			FO							
ACE					FO	FO							
BGE[6]	RT	EH		IB RB		FO							
Pepco DC						IT	RT		EH	IB RB	FO	FO	FO
Pepco MD						IT	RT		EH	IB RB		FO	

	Revenue Requirement	Requested ROE / Equity Ratio	Expected/Received Order Date
DPL DE Electric	$39.3M[1,2]	10.50% / 50.50%	Q2 2024
ComEd[3]	$1.49B[1,4] 4-Year MYP	2024: 10.50% / 50.58% 2025: 10.55% / 50.81% 2026: 10.60% / 51.03% 2027: 10.65% / 51.19%	Dec 2023
ACE	$92.0M[1,5]	10.50% / 50.20%	Q1 2024
BGE[6]	$602.3M[1,7] 3-Year MYP	10.40% / 52.00%	Dec 2023
Pepco DC	$190.7M[1,8] 3-Year MYP	10.50%/ 50.50%	Q2/Q3 2024[8]
Pepco MD	$213.6M[1,10] 3-Year MYP	10.50%/ 50.50%	Jun 2024[11]

CF Rate case filed
IT Intervenor direct testimony
RT Rebuttal testimony
EH Evidentiary hearings
IB Initial briefs
RB Reply briefs
FO Final commission order
SA Settlement agreement

Note: Unless otherwise noted, based on schedules of Illinois Commerce Commission (ICC), Maryland Public Service Commission (MDPSC), Pennsylvania Public Utility Commission (PAPUC), Delaware Public Service Commission (DPSC), Public Service Commission of the District of Columbia (DCPSC), and New Jersey Board of Public Utilities (NJBPU) that are subject to change.

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings.
(2) Requested revenue requirement excludes the transfer of $14.4M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power implemented full proposed rates on Jul 15, 2023, subject to refund.
(3) ComEd's MYP schedule shown above. On Apr 21, 2023, ComEd also filed its 2022 formula rate reconciliation seeking recovery of $247M for rates effective on Jan 1, 2024. Reply briefs were filed on Oct 19, 2023. An order is expected by Dec 17, 2023.
(4) Reflects 4-year cumulative multi-year rate plan. ComEd proposes a three-tranche phase in plan that accrues revenues but defers recovery of 35% of the 2024 increase of $968M until 2026, 10% of the 2025 increase after phase-in until 2027, and 35% of the 2026 revenue increase after phase-in until 2028.
(5) ACE's procedural schedule was suspended in Sep 2023. On Oct 21st, ACE filed a stipulation of settlement with the NJBPU. Subsequently, on Oct 24th, the Administrative Law Judge presiding over the case recommended the settlement with all parties be approved. ACE is awaiting final approval of the settlement from the NJBPU and it is expected in Q4 2023.
(6) In its Annual Informational Filings filed with the MDPSC on Mar 31, 2022 and Mar 31, 2023, BGE is requesting to recover an imbalance of $17.8M for 2021 and $58.7M for 2022. An order is expected to coincide with MYP by Dec 14, 2023.
(7) Reflects 3-year cumulative multi-year plan. Company proposed incremental revenue requirement increases with rates effective Jan 1, 2024, Jan 1, 2025, and Jan 1, 2026, respectively. The proposed revenue requirement increase in 2024 reflects $84.8M increase for electric and $158.3M increase for gas; 2025 reflects $103.3M increase for electric and $77.0M increase for gas; 2026 reflects $125.0M increase for electric and $54.0M increase for gas. These include a proposed acceleration of certain tax benefits in 2024 and 2025 for electric, and 2024 for gas. Revenue requirement includes ~$25M for the Customer Electrification Plan which the MDPSC struck from BGE's MYP 2 proceeding in Q3 2023.
(8) Reflects 3-year cumulative multi-year plan. Company proposed incremental revenue requirement increases of $116.4M, $36.9M, and $37.3M with rates effective Feb 15, 2024, Jan 1, 2025, and Jan 1, 2026, respectively. The cumulative revenue requirement does not total to $190.7 million due to rounding. Pepco cannot predict the exact timing of the DCPSC decision.
(9) Reflects 3-year cumulative multi-year plan with a proposed 9-month extension. Company proposed incremental revenue requirement increases with rates effective Apr 1, 2024, Apr 1, 2025, Apr 1, 2026, and Apr 1, 2027. Pepco proposes to extend this MYP through Dec 31, 2027 to position utilities currently operating under MYPs to file future applications on staggered schedules and avoid over-burdening Commission Staff and other parties. An order is expected by Jun 2024.
(10) Based on the settlement agreement approved on August 7, 2023 to (a) establish a revenue deferral mechanism to allow the Company to recover its full Commission-authorized 12-month rate year 1 increase between Jul 1, 2024 through Mar 31, 2025, and (b) extend the procedural schedule to address intervenor resource constraints

Delmarva DE (Electric) Distribution Rate Case Filing

Rate Case Filing Details		Notes
Docket No.	22-0897	• December 15, 2022, Delmarva Power filed an application with the Delaware Public Service Commission (DPSC) seeking an increase in electric distribution rates • This rate increase will support significant investments in infrastructure to maintain safety, reliability and customer service for our customers, as well as address emerging macroeconomic factors, specifically inflationary pressures and increased storm costs • September 29, 2023, Delmarva Power filed 12+0 rebuttal testimony based on twelve months actual ending June 30, 2023; update to test period resulted in revised revenue requirement request of $39.3M
Test Period	July 1 – June 30	
Test Year	12 month actual	
Proposed Common Equity Ratio	50.50%	
Proposed Rate of Return	ROE: 10.50%; ROR: 7.42%	
Proposed Rate Base (Adjusted)	$1,081M	
Requested Revenue Requirement Increase	$39.3M(1,2)	
Residential Total Bill % Increase	5.08%	

Detailed Rate Case Schedule

	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr
Filed rate case	12/15/2022																
Intervenor testimony									8/18/2023								
Rebuttal testimony										9/29/2023							
Evidentiary hearings													12/4/2023 - 12/7/2023				
Initial briefs																	
Reply briefs																	
Commission order expected																Q2 2024	

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings.
(2) Requested revenue requirement excludes the transfer of $14.4M of revenues from the Distribution System Improvement Charge (DSIC) capital tracker into base distribution rates. As permitted by Delaware law, Delmarva Power implemented full proposed rates on July 15, 2023, subject to refund.

exelon

ComEd Distribution Rate Case Filing

Multi-Year Plan Case Filing Details		Notes
Formal Case No.	23-0055	• January 17, 2023, ComEd filed a four-year multi-year plan (MYP) request with the Illinois Commerce Commission (ICC) seeking an increase in electric distribution base rates, updated with changes through September 27, 2023 • Proposal aligns with the investments in ComEd MYIGP, which was also filed with the ICC on January 17, 2023. The two cases were consolidated into a single proceeding on January 23, 2023 • Proposal includes a phase-in of new rates, deferring 35% of the first year's bill impact until 2026, 10% of the second year's bill impact until 2027, and 35% of the third year's bill impact until 2028, as allowed under CEJA • On October 23, 2023, the ALJs issued their Proposed Order which includes ~$300M reduction in revenue requirement over the MYP, a fixed ROE of 9.28%, and a common equity ratio of 50% • Separately, on April 21, 2023, ComEd filed its 2022 formula rate reconciliation seeking recovery of $247M for rates effective on January 1, 2024. Reply briefs were filed on October 19, 2023. An order is expected by December 17, 2023
Test Period	January 1 – December 31	
Test Year	2024, 2025, 2026, 2027	
Proposed Common Equity Ratio	50.58% in 2024 increasing to 51.19% in 2027	
2024-2027 Proposed Rate of Return	ROE: 10.50%, 10.55%, 10.60%, 10.65% ROR: 7.43%, 7.50%, 7.62%, 7.70%	
2024-2027 Proposed Rate Base (Adjusted)	$15.4B; $16.4B; $17.4B; $18.3B	
2024-2027 Requested Revenue Requirement Increase	$968M, $181M, $164M, $175M(1,2)	
2024-2027 Residential Total Bill % Increase	7.0%, 5.5%, 9.6%, (3.7%)(3)	

Detailed Rate Case Schedule

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan
Filed rate case	1/17/2023												
Intervenor testimony					5/22/2023								
Rebuttal testimony						6/27/2023							
Evidentiary hearings								8/21/2023					
Initial briefs									9/12/2023				
Reply briefs									9/27/2023				
Commission order expected												12/14/2023(4)	

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings.
(2) Reflects the revenue requirement increases in ComEd's surrebuttal testimony without the effects of ComEd's proposed phase-in approach. ComEd proposes a three-tranche phase-in plan that accrues revenues but defers recovery of 35% of the 2024 increase of $968M until 2026, 10% of the 2025 increase after phase-in of $520M until 2027, and 35% of the 2026 revenue increase after phase-in of $215M until 2028.
(3) Includes the effects of the proposed phase-in approach.
(4) Commission order expected on 12/14/2023.

ACE Distribution Rate Case Filing

Rate Case Filing Details	
Docket No.	ER23020091
Test Period	July 1 – June 30
Test Year	12 months actual
Proposed Common Equity Ratio	50.20%
Proposed Rate of Return	ROE: 10.50%; ROR: 7.13%
Proposed Rate Base (Adjusted)	$2,119M
Requested Revenue Requirement Increase	$92.0M(1)
Residential Total Bill % Increase	8.27%

Notes

- February 15, 2023, ACE filed a distribution base rate case with the New Jersey Board of Public Utilities (NJBPU) to increase distribution base rates
- This rate increase will support significant investments in infrastructure to maintain safety, reliability and customer service for customers
- Includes initial recovery for ACE's smart meter deployment ("Smart Energy Network") and EVsmart program
- Addresses macroeconomic factors, specifically inflationary pressures and increased storm costs, and includes a Prudency Review for the PowerAhead program, which made storm-hardening investments from 2017-2022
- August 21, 2023, ACE filed 12+0 supplemental direct testimony based on twelve months actual data ending June 30, 2023; update to test period resulted in revised revenue requirement request of $92.0M

Detailed Rate Case Schedule(2)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Filed rate case	2/15/2023	▲										
Intervenor testimony												
Rebuttal testimony												
Evidentiary hearings												
Initial briefs												
Reply briefs												
Commission order expected										Q4 2023	■	■

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings.
(2) ACE's procedural schedule was suspended in September 2023. On October 21st, ACE filed a stipulation of settlement with the NJBPU. Subsequently, on October 24th, the Administrative Law Judge presiding over the case recommended the settlement with all parties be approved. ACE is awaiting final approval of the settlement from the NJBPU and it is expected in Q4 2023.

BGE Distribution Rate Case Filing

Multi-Year Plan Case Filing Details	
Formal Case No.	9692
Test Period	January 1 – December 31
Test Year	2024, 2025, 2026
Proposed Common Equity Ratio	52.00%
2024-2026 Proposed Rate of Return	ROE: 10.4% ROR: 7.39%, 7.45%, 7.56%
2024-2026 Proposed Rate Base (Adjusted)	$8.1B, $8.8B, $9.5B
2024-2026 Requested Revenue Requirement Increase[1,2]	$243.1M, $180.3M, $179.0M
2024-2026 Residential Total Bill % Increase[2]	6.8%, 4.5%, 3.7%

Notes

- February 17, 2023, BGE filed a three-year multi-year plan (MYP) request with the Maryland Public Service Commission (MDPSC) seeking an increase in electric and gas distribution base rates.
- The proceeding will also reconcile the first two years of BGE's first MYP. BGE is requesting to recover an imbalance[3] of $17.8M and $58.7M for 2021 and 2022, respectively
- The increase is driven by investments to continue providing safe and reliable electric and gas distribution service to customers while laying the foundation for BGE to support the achievement of Maryland's climate goals

Detailed Rate Case Schedule

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan
Filed rate case		2/17/2023											
Intervenor testimony						6/20/2023							
Rebuttal testimony							7/31/2023						
Evidentiary hearings								8/30/2023 – 9/8/2023					
Initial briefs										10/10/2023			
Reply briefs										10/20/2023			
Commission order expected												12/14/2023[4]	

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings.
(2) Reflects an average residential customer receiving both electric and gas service from BGE. Company proposed incremental revenue requirement increases with rates effective January 1, 2024, January 1, 2025, and January 1, 2026, respectively. The proposed revenue requirement increase in 2024 reflects $84.8M increase for electric and $158.3M increase for gas; 2025 reflects $103.3M increase for electric and $77.0M increase for gas; 2026 reflects $125.0M increase for electric and $54.0M increase for gas. These include a proposed acceleration of certain tax benefits in 2024 and 2025 for electric, and 2024 for gas. Revenue requirement includes ~$25M for the Customer Electrification Plan which the MDPSC struck from BGE's MYP 2 proceeding in Q3 2023.
(3) Reflects the imbalanced amounts included in the 2021 and 2022 Annual Informational Filings filed with the MDPSC on March 31, 2022 and March 31, 2023, respectively. The reconciliation of 2021 and 2022 costs are not included in the requested revenue requirement increase. BGE is proposing that these amounts be recovered through separate electric and gas riders in 2024.
(4) Expected Order Date per Statute.

Pepco DC Distribution Rate Case Filing

Multi-Year Plan Case Filing Details	
Formal Case No.	1176
Test Period	January 1 – December 31
Test Year	2024, 2025, 2026
Proposed Common Equity Ratio	50.50%
2024-2026 Proposed Rate of Return	ROE: 10.5% ROR: 7.77%, 7.78%, 7.79%
2024-2026 Proposed Rate Base (Adjusted)	$3.0B, $3.2B, $3.4B
2024-2026 Requested Revenue Requirement Increase[1,2]	$116.4M, $36.9M, $37.3M
2024-2026 Residential Total Bill % Increase[2]	6.4%, 6.0%, 5.6%

Notes

- April 13, 2023, Pepco submitted its "Climate Ready Pathway DC" three-year multi-year plan (MYP) application to the Public Service Commission of the District of Columbia (DCPSC) seeking an increase in electric distribution base rates
- This proposal outlines investments the company will make from 2024-2026 to support a climate ready grid and help support the District's clean energy goals
- The MYP includes a proposal expanding enrollment for the RAD program, operated by the District Department of Energy and Environment, to include more Pepco DC customers who qualify for any low-income program in the District

Detailed Rate Case Schedule

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Filed rate case	4/13/2023														
Intervenor testimony									12/11/2023						
Rebuttal testimony											1/29/2024				
Evidentiary hearings												3/25/2024 - 3/26/2024			
Initial briefs													4/17/2024		
Reply briefs														5/1/2024	
Commission order expected													Q2/Q3 2024[3]		

(1) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings.
(2) Company proposed incremental revenue requirement increases with rates effective February 15, 2024, January 1, 2025, and January 1, 2026. The cumulative revenue requirement does not total to $190.7 million due to rounding.
(3) Pepco cannot predict the exact timing of the DCPSC decision.

Pepco MD Distribution Rate Case Filing

Multi-Year Plan Case Filing Details	
Formal Case No.	9702
Test Period	April 1 – March 31
Test Year(1)	2024, 2025, 2026, 2027
Proposed Common Equity Ratio	50.50%
2024-2026 Proposed Rate of Return	ROE: 10.50% ROR: 7.77%, 7.79%, 7.80%, 7.81%
2024-2026 Proposed Rate Base (Adjusted)	$2.6B, $2.8B, $2.9B, $3.0B
2024-2026 Requested Revenue Requirement Increase(2,3)	$74.4M, $59.4M, $59.4M, $20.4M
2024-2026 Residential Total Bill % Increase(3)	5.0%, 3.8%, 3.7%, 1.2%

Notes

- May 16, 2023, Pepco submitted its "Climate Ready Pathway MD" three-year multi-year plan (MYP) application with proposed 9-month extension to the Maryland Public Service Commission (MDPSC) seeking an increase in electric distribution base rates
- This proposal outlines investments the company will make from 2024-2027 to advance the state's climate and clean energy goals while taking steps to mitigate the impact of these efforts on customer bills
- The MYP includes investments in innovative technologies, communications and information technology, reliability and customer-driven projects, and necessary system capacity enhancements needed to support customers through the current energy transformation

Detailed Rate Case Schedule

	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
Filed rate case	5/16/2023													
Intervenor testimony								12/15/2023						
Rebuttal testimony									1/26/2024					
Evidentiary hearings											3/7/2024 - 3/13/2024			
Initial briefs												4/8/2024		
Reply briefs												4/22/2024		
Commission order expected(4)														June 2024

(1) Pepco is proposing to extend this MYP through December 31, 2027 in order to position utilities currently operating under MYPs to file future applications on staggered schedules and avoid over-burdening Commission Staff and other parties.
(2) Revenue requirement includes changes in depreciation and amortization expense and other costs where applicable, which have no impact on pre-tax earnings. Additionally, Pepco is proposing acceleration of additional tax benefits to offset Rate Year 1 and Rate Year 2 bill impacts. Revenue requirement includes the impact of these proposed offsets.
(3) Company proposed incremental revenue requirement increases for 3-year multi-year plan with proposed 9-month extension for rates effective April 1, 2024, April 1, 2025, April 1, 2026, and April 1, 2027.
(4) Based on the settlement agreement approved on August 7, 2023 to (a) establish a revenue deferral mechanism to allow the Company to recover its full Commission-authorized 12-month rate year 1 increase between July 1, 2024 through March 31, 2025, and (b) extend the procedural schedule to address intervenor resource constraints.

Utility Highlights

	comed AN EXELON COMPANY	peco AN EXELON COMPANY	bge AN EXELON COMPANY	pepco AN EXELON COMPANY	delmarva power AN EXELON COMPANY	atlantic city electric AN EXELON COMPANY
2022 Electric Customer Mix (% of Volumes)[(1)]						
Commercial & Industrial (C&I)	66%	59%	55%	63%	55%	52%
Residential	33%	39%	44%	34%	45%	48%
Public Authorities/Other	1%	2%	1%	3%	0%	1%
2022 Gas Customer Mix (% of Volumes)[(1)]						
Commercial & Industrial (C&I)	-	26%	52%	-	28%	-
Residential	-	46%	41%	-	41%	-
Public Authorities/Other	-	28%	7%	-	31%	-
Current Rate Recovery Mechanisms						
Traditional Base Rate Application	-	-	-	-	X - DE Only	X
Distribution Formula Rate	X[(2)]	-	-	-	-	-
Multi-Year Plan	-	-	X	X	X – MD Only	-
Fully Projected Future Test Year	-	X	-	-	-	-
Transmission Formula Rate	X	X	X	X	X	X
Tracker Mechanisms for Specified Investments/Programs	X	X	X	X	X	X
Decoupling[(3)]	X	-	X	X	X - MD Only	X
Bad Debt Tracker	X	-	-	-	-	X
Major Storm Deferral	X[(4)]	-	X	X[(5)]	X - MD Only	X

Note: "-" cells are indicative of categories that are not applicable to the respective utility
(1) Percent of volumes by customer class may not sum due to rounding.
(2) ComEd distribution formula rate expired in 2022, but 2023 rates are based on the final formula rate approved in November 2022. 2024 rates will be based on the multi-year rate plan order expected in December 2023.
(3) ComEd's formula rate includes a mechanism that eliminates volumetric risk. Rider DSPR – Delivery Service Pricing Reconciliation will provide decoupling for calendar years 2022 and 2023 after the formula rate expires, while Rider RBA – Revenue Balancing Adjustment, which was approved by the Illinois Commerce Commission in December 2022, will provide decoupling for 2024 and beyond. ACE implemented the Conservation Incentive Program prospectively effective July 1, 2021, which eliminates the variable effects of weather and customer usage patterns for most customers. Certain classes for BGE, DPL MD, Pepco and ACE are not decoupled.
(4) Under EIMA statute (220 ILCS 5/16-108.5) and CEJA (220 ILCS 5/16-105.6), ComEd is able to record expenses greater than $10 million resulting from a single storm or weather system or other similar expense to a regulatory asset and amortize over 5 years.
(5) In the Pepco DC MYP case, the Company received approval on June 8, 2021 for the ability to request deferral of unexpected costs greater than $1M which could enable regulatory asset treatment for storm recovery.

Commission Overview

	Illinois	Pennsylvania	Maryland	District of Columbia	Delaware	New Jersey
Commissioners[1]						
Name (Party/Term Expiration)	**Doug Scott (D) (2024)**[2] Michael Carrigan (D) (2025) Ann McCabe (R) (2027) Conrad Reddick (D) (2028) Stacey Paradis (R) (2028)	**Stephen DeFrank (D) (2025)** Kim Barrow, Vice Chair (D) (2028) Ralph Yanora (R) (2024) Kathryn Zerfuss (D) (2026) John Coleman, Jr. (R) (2027)	**Fred Hoover (D) (2028)** Michael Richard (R) (2025) Anthony O'Donnell (R) (2026) Bonnie Suchman (D) (2027) Kumar Barve (D) (2028)	**Emile Thompson (D) (2026)** Richard Beverly (D) (2024) Ted Trabue (D) (2026)	**Dallas Winslow (R) (2025)** Harold Gray (D) (2024) Joann Conaway (D) (2025) Kim Drexler (D) (2025) Mike Karia (I) (2025)	**Christine Guhl-Sadovy (D) (2029)** Marian Abdou (R) (2025) Mary-Anna Holden (R) (2026) Zenon Christodoulou (D) (2026) Open Seat
Key Commission Details						
Appointment	Commissioners are appointed by the governor and confirmed by the Senate; chair appointed by governor	Commissioners are appointed by the governor and require 2/3 consent by the Senate; chair appointed by governor	Commissioners are appointed by the governor and confirmed by the Senate; chair appointed by governor	Commissioners and the chair are appointed by the Mayor with the consent of the District Council	Commissioners are appointed by the governor and confirmed by the Senate; chair appointed by governor	Commissioners are nominated by the governor and confirmed by the Senate; president appointed by the governor
Term	5-year term with term expirations intended to be staggered yearly	5-year term with term expirations intended to be staggered yearly	5-year term with term expirations intended to be staggered yearly	4-year term with term expirations intended to be staggered yearly	4-year term	6-year term with president to serve until a successor has been designated
Legislative Considerations						
Legislature in Session	IL General Assembly convenes each January until May 31. Reconvenes for 2 weeks in the fall for Veto Session	PA General Assembly meets regularly throughout the year	MD General Assembly convenes each January for 90 days. Special session is held when called by the governor or when a majority of each house petitions the governor	The District Council meets on the first Tuesday of every month	DE General Assembly convenes on the second Tuesday of January and meets on Tuesdays, Wednesdays and Thursdays until June 30 of each year	NJ General Assembly typically convenes Mondays and Thursdays throughout the year

Note: reflects most recent available data as of October 31, 2023
(1) Chairperson and/or President denoted in bold.
(2) IL Governor JB Pritzker appointed Doug Scott to replace Carrie Zalewski as the Chair of the Illinois Commerce Commission effective mid-June 2023 with his term ending in 2024.

Approved Distribution Rate Case Financials

Approved Electric Distribution Rate Case Financials	Revenue Requirement Increase/(Decrease)	Allowed ROE	Common Equity Ratio	Rate Effective Date
ComEd (Electric)	$198.9M	7.85%	49.45%	Jan 1, 2023
PECO (Electric)(1)	$132.0M	N/A	N/A	Jan 1, 2022
BGE (Electric)(2)	$139.9M	9.50%	52.00%	Jan 1, 2021
Pepco MD (Electric)(3)	$52.2M	9.55%	50.50%	Jun 28, 2021
Pepco D.C. (Electric)(4)	$108.6M	9.275%	50.68%	Jul 1, 2021
DPL MD (Electric)(5)	$28.9M	9.60%	50.50%	Jan 1, 2023
DPL DE (Electric)	$13.5M	9.60%	50.37%	Oct 6, 2020
ACE (Electric)	$41.0M	9.60%	50.21%	Jan 1, 2022

Approved Gas Distribution Rate Case Financials	Revenue Requirement Increase/(Decrease)	Allowed ROE	Common Equity Ratio	Rate Effective Date
PECO (Gas)	$54.8M	N/A	N/A	Jan 1, 2023
BGE (Gas)(2)	$73.9M	9.65%	52.00%	Jan 1, 2021
DPL DE (Gas)	$7.6M	9.60%	49.94%	Nov 1, 2022

(1) The PaPUC issued an order on November 18, 2021 approving the Joint Petition for Settlement with rates effective on January 1, 2022. The settlement does not stipulate any ROE, Equity Ratio or Rate Base.

(2) Reflects a three-year cumulative multi-year plan for 2021 through 2023. The MDPSC awarded BGE electric revenue requirement increases of $59 million, $39 million, and $42 million, before offsets, in 2021, 2022, and 2023, respectively, and natural gas revenue requirement increases of $53 million, $11 million, and $10 million, before offsets, in 2021, 2022, and 2023, respectively. The MDPSC utilized the tax benefits to fully offset the increases in 2021 and January 2022 such that customer rates remained unchanged. For the remainder of 2022, the MDPSC chose to offset only 25% of the cumulative 2021 and 2022 electric revenue requirement increases and 50% of the cumulative gas revenue requirement increases. After deferring a decision on 2023 and asking BGE to make a new proposal, the MDPSC accepted BGE's recommendation in October 2022 to not use certain tax benefits to offset 2023 revenue requirement increases.

(3) Reflects a three-year cumulative multi-year plan for April 1, 2021 through March 31, 2024. The MDPSC awarded Pepco electric incremental revenue requirement increases of $21 million, $16 million, and $15 million, before offsets, for the 12-month periods ending March 31, 2022, 2023, and 2024, respectively. The MDPSC offset customer rate increases through March 31, 2022 with certain accelerated tax benefits, but deferred the decision to use additional tax benefits to offset customer rate increases for the periods after March 31, 2022.

(4) Reflects a cumulative multi-year plan with 18-months remaining in 2021 through 2022. The DCPSC awarded Pepco electric incremental revenue requirement increases of $42 million and $67 million, before offsets, for the remainder of 2021 and 2022, respectively. However, the DCPSC utilized the acceleration of refunds for certain tax benefits along with other rate relief to partially offset the customer rate increases by $22 million and $40 million for the remainder of 2021 and 2022, respectively.

(5) Reflects 3-year cumulative multi-year plan. On October 7, 2022, DPL filed a partial settlement with the MDPSC, which included incremental revenue requirement increases of $16.9M, $6.0M and $6.0M with rates effective January 1, 2023, January 1, 2024, and January 1, 2025, respectively. The MDPSC approved the settlement without modification on December 14, 2022.

Approved Electric Transmission Formula Rate Financials

Approved Electric Transmission Formula Rate Financials	Revenue Requirement Increase/(Decrease)	Allowed ROE(1)	Common Equity Ratio	Rate Effective Date(2)
ComEd	$83M	11.50%	55.00%	Jun 1, 2023
PECO	$30M	10.35%	54.12%	Jun 1, 2023
BGE	$7M	10.50%	53.48%	Jun 1, 2023
Pepco	$32M	10.50%	50.50%	Jun 1, 2023
DPL	$29M	10.50%	50.31%	Jun 1, 2023
ACE	$29M	10.50%	50.02%	Jun 1, 2023

(1) The rate of return on common equity for each Utility Registrant includes a 50-basis-point incentive adder for being a member of a RTO.
(2) All rates are effective June 1, 2023 - May 31, 2024, subject to review by interested parties pursuant to protocols of each tariff.

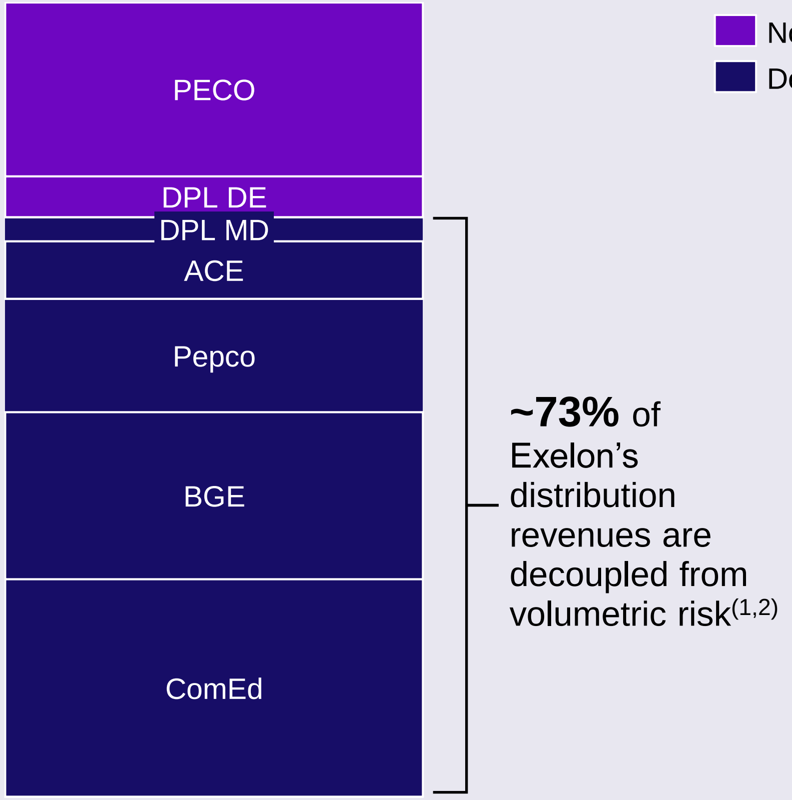
Tracker Recovery Mechanisms for Specified Investments / Programs

Delaware	• Distribution System Improvement Charge (DSIC) tracker provides a mechanism to begin recovering gas and electric infrastructure investments for reliability every six months
District of Columbia	• District of Columbia Power Line Undergrounding (DC PLUG) provides for contemporaneous recovery of reliability and resiliency investments to underground the most vulnerable feeders
Illinois	• Future Energy Jobs Act (FEJA) permits recovery of energy efficiency programs and distributed generation rebates through formula rates
Maryland(1,2)	• Strategic Infrastructure Development and Enhancement (STRIDE) program allows for contemporaneous recovery of the accelerated replacement of aging gas infrastructure (cast iron and bare steel mains and copper, bare steel and pre-1970 ¾” high pressure steel services) • EmPOWER MD allows for recovery on energy efficiency and demand response programs
New Jersey	• Infrastructure Investment Program (IIP) regulations permit the recovery of certain capital investments, primarily related to safety and reliability, through a capital tracker recovery mechanism • ACE Energy Efficiency program allows for recovery on approximately $100M of energy efficiency programs through 2025
Pennsylvania	• Distribution System Improvement Charge (DSIC) mechanism provides recovery for Long-Term Infrastructure Improvement Plan (LTIIP) for electric and gas distribution in between rate cases

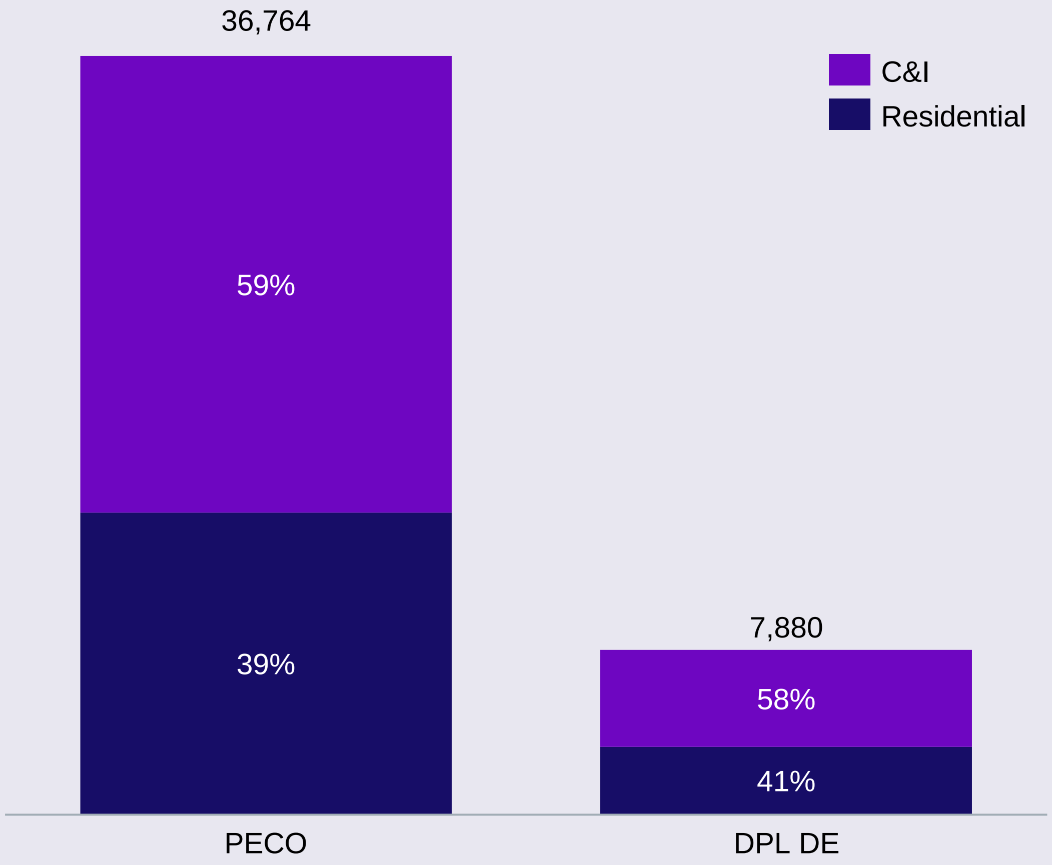
(1) In August 2022, the MD PSC issued an order directing the utilities to phase out the regulatory asset treatment for the EmPOWER MD program by 2029. The phase out requires 33% of the EmPOWER MD program’s costs to be treated as O&M in 2024 with the remaining costs residing in the regulatory asset. For 2025, the O&M component of the program’s costs grows to 67%, with the full 100% of the costs treated as O&M beginning in 2026.
(2) BGE has proposed to include aging gas infrastructure replacement work, currently recovered under the STRIDE program, in MYP base rates beginning in 2024.

Revenue Decoupling Mitigates Load Fluctuation Impacts

Revenue Decoupling Mitigates Load Fluctuations



Non-Decoupled Load Volumes (GWh)(3)



(1) Reflects 2022 electric and gas revenues; ComEd's formula rate includes a mechanism that eliminates volumetric risk. Rider DSPR – Delivery Service Pricing Reconciliation will provide decoupling for calendar years 2022 and 2023 after the formula rate expires, while Rider RBA – Revenue Balancing Adjustment, which was approved by the Illinois Commerce Commission in December 2022, will provide decoupling for 2024 and beyond. ACE implemented the Conservation Incentive Program prospectively effective July 1, 2021, which eliminates the variable effects of weather and customer usage patterns for most customers.

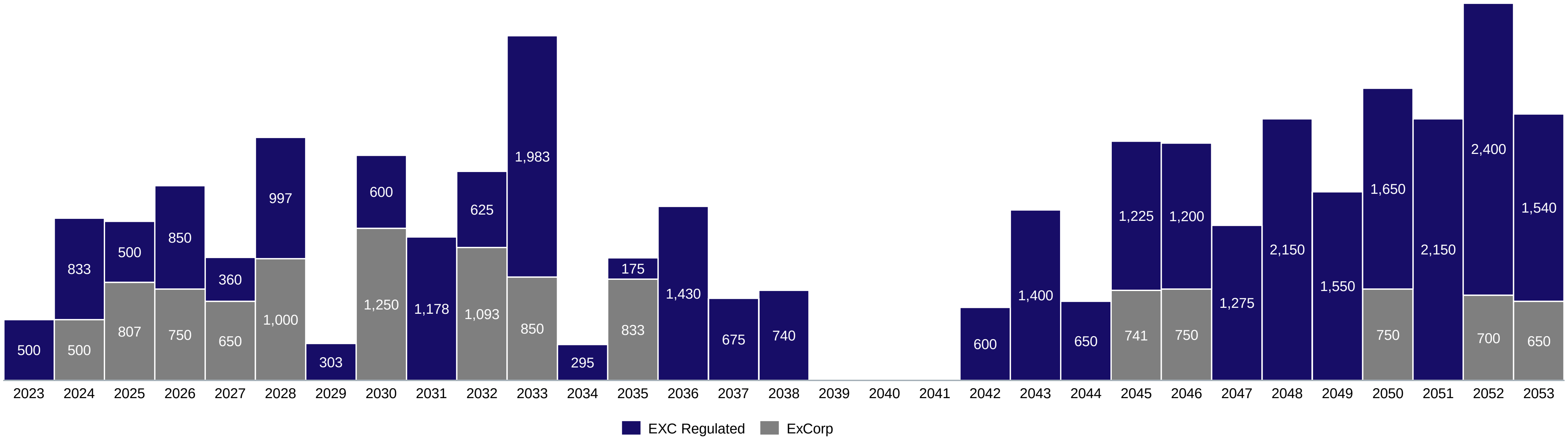
(2) Certain classes for BGE, DPL MD, Pepco and ACE are not decoupled.

(3) Reflects 2022 electric volumes; remainder of volumes not captured in chart reflect public authorities or other customers.

Exelon Debt Maturity Profile[1,2]

As of 9/30/2023
($M)

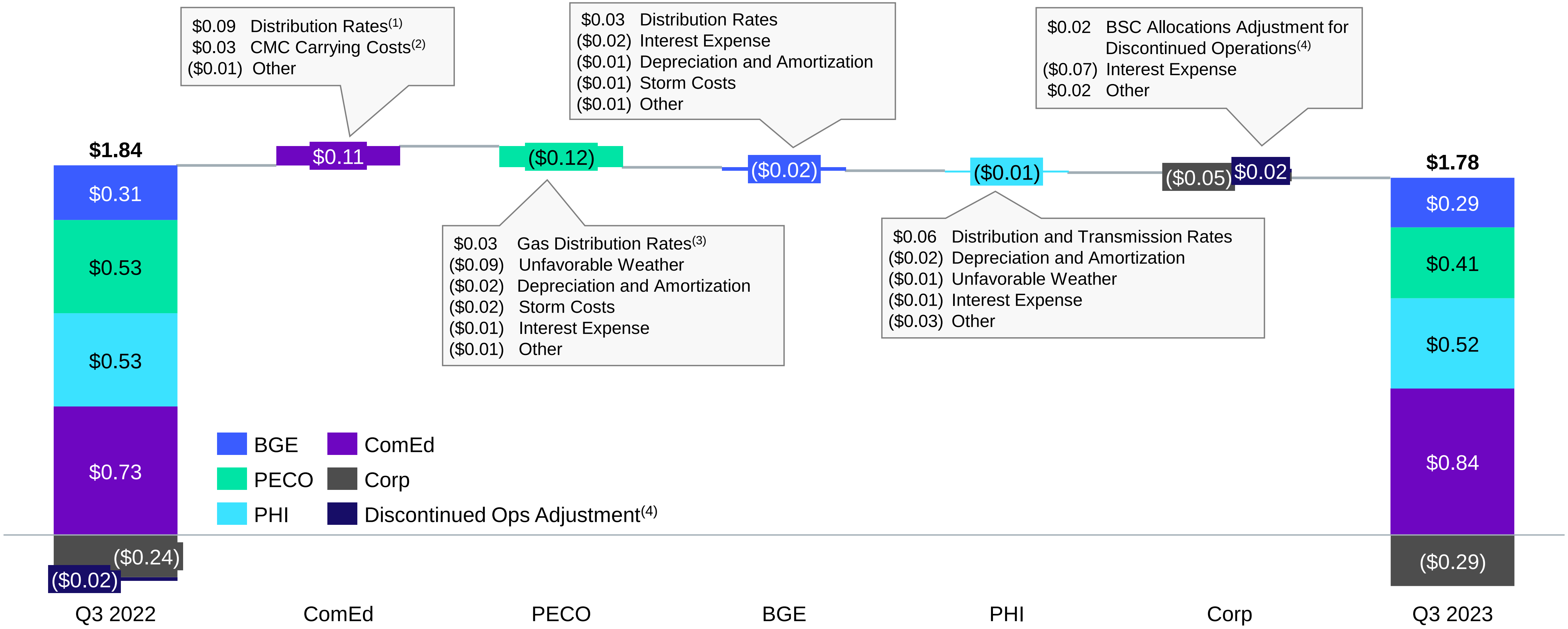
	Debt Balances (as of 9/30/23)[1,2]		
	Short-Term Debt	Long-Term Debt[4]	Total Debt
BGE	$0.1B	$4.6B	$4.7B
ComEd	$0.7B	$11.7B	$12.4B
PECO	-	$5.3B	$5.3B
PHI	$0.2B	$8.6B	$8.8B
Corp	$0.8B[3]	$11.2B[4]	$12.0B
Exelon	**$1.7B**	**$41.5B**	**$43.2B**



Exelon's weighted average long-term debt maturity is approximately 16 years

(1) Maturity profile excludes non-recourse debt, securitized debt, capital leases, fair value adjustments, unamortized debt issuance costs and unamortized discount/premium.
(2) Long-term debt balances reflect 2023 Q3 10-Q GAAP financials, which include items listed in footnote 1.
(3) Includes $500M of 364-day term loan maturing March 2024.
(4) Includes $500M of 18-month term loans maturing in April 2024.

Q3 2023 YTD Adjusted Operating Earnings* Waterfall



Note: Amounts may not sum due to rounding

(1) Reflects higher allowed electric distribution ROE due to an increase in treasury rates and higher rate base.

(2) Reflects revenue related to the carbon mitigation credit (CMC) regulatory asset carrying costs. Beginning in June 2022 ComEd provided CMC bill credits to customers, and a mismatch between the credits and the cash paid from participating nuclear-powered facilities is being carried as a regulatory asset by ComEd outside of the distribution formula rate. Beginning in 2023 ComEd is recovering a portion of those incremental financing costs, which are not included here, through the required application of the ICC determined customer deposit rate of 5% on the remaining uncollected balance.

(3) Reflects new gas distribution rates effective on January 1, 2023.

(4) Reflects certain BSC costs that were historically allocated to ExGen but are presented as part of continuing operations in Exelon's results as these costs do not qualify as expenses of the discontinued operations per the accounting rules.

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Exelon Adjusted Operating Earnings* Sensitivities

Interest Rate Sensitivity to +50bp	2023E	2024E
30-Year US Treasury Yield(1)	$0.01	$0.00
Cost of Debt(2)	$(0.00)	$(0.01)

Exelon Consolidated Effective Tax Rate	16.5%	8.9%
Exelon Consolidated Cash Tax Rate	9.2%	8.3%

(1) Reflects full year impact to a +50bp increase on the 30-Year US Treasury Yield impacting ComEd's ROE net of Corporate 30-year swap impacting Exelon's adjusted operating earnings* as of September 30, 2023. Beyond 2023, Exelon's sensitivity relates to other ComEd long-term regulatory assets tied to interest rates, including Energy Efficiency and the Solar Rebate Program. As of September 30, 2023, Corporate entered into ~$4.9B of 30-year swaps.
(2) Reflects full year impact to a +50bp increase on Corporate debt net of pre-issuance hedges and floating-to-fixed interest rate swaps as of September 30, 2023. Through September 30, 2023, Corporate entered into $780M of pre-issuance hedges through interest rate swaps.

Reconciliation of Non-GAAP Measures

Projected GAAP to Operating Adjustments

- **Exelon's projected 2023 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
  - Mark-to-market adjustments from economic hedging activities;
  - Certain costs related to a change in environmental liabilities;
  - Costs related to a change in the SEC matter loss contingency;
  - Costs related to a change in ComEd's FERC audit liability;
  - Costs related to the separation;
  - Income tax-related adjustments; and
  - Other items not directly related to the ongoing operations of the business.

GAAP to Non-GAAP Reconciliations(1)

S&P FFO/Debt(2) = FFO (a) / Adjusted Debt (b)

Moody's CFO (Pre-WC)/Debt(3) = CFO (Pre-WC) (c) / Adjusted Debt (d)

S&P FFO Calculation(2)

GAAP Operating Income
<u>+ Depreciation & Amortization</u>
= EBITDA
- Cash Paid for Interest
+/- Cash Taxes
<u>+/- Other S&P FFO Adjustments</u>
= FFO (a)

S&P Adjusted Debt Calculation(2)

Long-Term Debt
+ Short-Term Debt
+ Underfunded Pension (after-tax)
+ Underfunded OPEB (after-tax)
+ Operating Lease Imputed Debt
- Cash on Balance Sheet
<u>+/- Other S&P Debt Adjustments</u>
= Adjusted Debt (b)

Moody's CFO (Pre-WC) Calculation(3)

Cash Flow From Operations
+/- Working Capital Adjustment
<u>+/- Other Moody's CFO Adjustments</u>
= CFO (Pre-Working Capital) (c)

Moody's Adjusted Debt Calculation(3)

Long-Term Debt
+ Short-Term Debt
+ Underfunded Pension (pre-tax)
+ Operating Lease Imputed Debt
<u>+/- Other Moody's Debt Adjustments</u>
= Adjusted Debt (d)

(1) Due to the forward-looking nature of some forecasted non-GAAP measures, information to reconcile the forecasted adjusted (non-GAAP) measures to the most directly comparable GAAP measure may not be currently available; therefore, management is unable to reconcile these measures.
(2) Calculated using S&P Methodology.
(3) Calculated using Moody's Methodology.

Q3 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2023	ComEd	PECO	BGE	PHI	Other	Exelon
2023 GAAP Earnings (Loss) from Continuing Operations Per Share	**$0.83**	**$0.41**	**$0.29**	**$0.49**	**($0.30)**	**$1.72**
Mark-to-Market Impact of Economic Hedging Activities	-	-	-	-	0.01	0.01
Change in Environmental Liabilities	-	-	-	0.03	-	0.03
SEC Matter Loss Contingency	-	-	-	-	0.05	0.05
Separation Costs	0.01	-	-	0.01	-	0.02
Change in FERC Audit Liability	0.01	-	-	-	-	0.01
Income Tax-Related Adjustments	-	-	-	-	(0.05)	(0.05)
2023 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.84**	**$0.41**	**$0.29**	**$0.52**	**($0.29)**	**$1.78**

Nine Months Ended September 30, 2022[1]	ComEd	PECO	BGE	PHI	Other	Exelon
2022 GAAP Earnings (Loss) from Continuing Operations Per Share	**$0.72**	**$0.48**	**$0.27**	**$0.53**	**($0.35)**	**$1.65**
Asset Impairments	-	-	0.04	-	-	0.04
Separation Costs	0.01	-	-	0.01	-	0.03
Income Tax-Related Adjustments	-	0.04	-	-	0.09	0.13
2022 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.73**	**$0.53**	**$0.31**	**$0.53**	**($0.26)**	**$1.84**

Note: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not sum due to rounding.

(1) Other and Exelon amounts include certain BSC costs that were historically allocated to ExGen but are presented as part of continuing operations in Exelon's results as these costs do not qualify as expenses of the discontinued operations per the accounting rules.

GAAP to Non-GAAP Reconciliations

Exelon Operating TTM ROE Reconciliation ($M)[1]	2016	2017	2018	2019	2020	2021	2022
Net Income (GAAP)	$1,103	$1,704	$1,836	$2,065	$1,737	$2,225	$2,501
Operating Exclusions	$461	($24)	$32	$30	$246	$82	$96
Adjusted Operating Earnings	$1,564	$1,680	$1,869	$2,095	$1,984	$2,307	$2,596
Average Equity[2]	$16,523	$17,779	$19,367	$20,913	$22,690	$24,967	$27,479
Operating (Non-GAAP) TTM ROE (Adjusted Operating Earnings/Average Equity)	**9.5%**	**9.4%**	**9.6%**	**10.0%**	**8.7%**	**9.2%**	**9.4%**

(1) Represents the twelve-month periods December 31, 2016-2022 for Exelon's utilities (excludes Corp and PHI Corp). Earned ROEs* represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Electric Transmission). Components may not reconcile to other SEC filings due to rounding.
(2) Reflects simple average book equity for Exelon's utilities less goodwill at ComEd and PHI.

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Thank you

Please direct all questions to the Exelon Investor Relations team:

InvestorRelations@ExelonCorp.com
312-394-2345