delmarva power
AN EXELON COMPANY

May 28, 2025

Mr. Andrew S. Johnston
Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

Dear Mr. Johnston

Submitted herewith is Delmarva Power & Light Company's ("DPL") Annual Report to the Public Service Commission of Maryland for the year ended December 31, 2024 as compiled on FERC Form No. 1 pursuant to the Commission's instructions.

We respectfully submit the following reports:

1. One (1) copy of the 2024 DPL Form 1, Annual Report which is the same report as filed with Federal Energy Regulatory Commission (FERC).
2. One (1) copy of the Addendum to 2024 Annual Report/Maryland Jurisdictional Electric Sales Statistics.
3. One (1) copy of the report of Energy Taxes and Property Taxes paid in 2024 to each municipal, county and state agency in Maryland.
4. One (1) copy of the Exelon First Quarter 2025 Form 10-Q (the most current corporate shareholder report).
5. Affidavit on cost allocations and transfer pricing of assets.

If you have any questions, please feel free to contact me at (667) 313-2673.

Sincerely,

Chris Ciccarone, CPA
Manager, External Financial Reporting, Exelon
Christopher.Ciccarone@exeloncorp.com

Enclosures

THIS FILING IS	
Item 1:	An Initial (Original) Submission OR Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Delmarva Power & Light Company	End of: 2024/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

- one million megawatt hours of total annual sales,
- 100 megawatt hours of annual sales for resale,
- 500 megawatt hours of annual power exchanges delivered, or
- 500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

“In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.” The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

FERC Forms 1 and 3-Q must be filed by the following schedule:

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

'Person' means an individual or a corporation;

'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

"project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1 (ED. 03-07)

FERC FORM NO. 1 REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER		
IDENTIFICATION		
01 Exact Legal Name of Respondent Delmarva Power & Light Company		02 Year/ Period of Report End of: 2024/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 500 North Wakefield Drive, Newark, Delaware 19702		
05 Name of Contact Person Jason T. Jones		06 Title of Contact Person Director of Accounting
07 Address of Contact Person (Street, City, State, Zip Code) 500 North Wakefield Drive, Newark, Delaware 19702		
08 Telephone of Contact Person, Including Area Code (302) 429-3225	09 This Report is An Original / A Resubmission (1) An Original (2) A Resubmission	10 Date of Report (Mo, Da, Yr) 12/31/2024
Annual Corporate Officer Certification		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name David M. Vahos 02 Title SVP, CFO & Treasurer	03 Signature David M. Vahos	04 Date Signed (Mo, Da, Yr) 03/25/2025
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

36	**Accumulated Deferred Investment Tax Credits**	266	
37	**Other Deferred Credits**	269	
38	**Accumulated Deferred Income Taxes-Accelerated Amortization Property**	272	N/A
39	**Accumulated Deferred Income Taxes-Other Property**	274	
40	**Accumulated Deferred Income Taxes-Other**	276	
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	
43	**Regional Transmission Service Revenues (Account 457.1)**	302	N/A
44	**Sales of Electricity by Rate Schedules**	304	
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	N/A
50	**Transmission of Electricity by Others**	332	N/A
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	
60	**Monthly ISO/RTO Transmission System Peak Load**	400a	
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	N/A
64	**Hydroelectric Generating Plant Statistics**	406	N/A
65	**Pumped Storage Generating Plant Statistics**	408	N/A
66	**Generating Plant Statistics Pages**	410	N/A
66.1	**Energy Storage Operations (Large Plants)**	414	N/A
66.2	**Energy Storage Operations (Small Plants)**	419	N/A
67	**Transmission Line Statistics Pages**	422	
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: Two copies will be submitted No annual report to stockholders is prepared		

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

	(2) A Resubmission		

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

David M. Vahos

Senior Vice President, Chief Financial Officer and Treasurer

500 North Wakefield Drive, Newark, Delaware 19702

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Incorporation: DE

Date of Incorporation: 1909-04-22

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable.

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Sale of electricity within the States of Delaware and Maryland, Sale of natural gas within the State of Delaware

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) Yes

(2) No

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

At December 31, 2024, Delmarva Power & Light Company (DPL) is controlled by Pepco Holdings LLC (PHI). PHI is controlled by PH Holdco LLC which is a special purpose subsidiary of Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon Corporation (Exelon). For additional information, see the Exelon Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2024.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1	President and Chief Executive Officer	Anthony, J. Tyler	592,250		
2	Sr. Vice President and Chief Operating Officer	Olivier, Tamla A.	438,494		
3	Sr. Vice President, Chief Financial Officer and Treasurer	Barnett, Phillip S.	450,243		2024-05-24
4	Sr. Vice President, Governmental, Regulatory and External Affairs	Oddoye, Rodney	412,626		
5	Vice President and General Counsel	Bancroft, Anne	370,000		
6	Corporate Secretary	Gayle Littleton	696,280		2024-12-31
7	Sr. Vice President, Chief Operating Officer, and Treasurer	Vahos, David	472,770	2024-05-24	
8	Corporate Secretary	Colette Honorable	618,000	2025-01-01	

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	J. Tyler Anthony (President & CEO)	701 Ninth Street, N.W., Washington, D.C. 20068	false	false
2	[(a)] Calvin G. Butler, Jr.	10 S. Dearborn Street, 54th Floor, Chicago, Illinois 60603	false	false
3	[(b)] Michael Innocenzo	2301 Market Street, Philadelphia, PA, 19101	false	false

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector

Effective March 31, 2024, Calvin Butler resigned from his role as Director.

(b) Concept: NameAndTitleOfDirector

Effective April 1, 2024, Michael Innocenzo assumed the role of Director.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	Yes No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	Attachment H-3D of PJM OATT	ER05-515
2	Attachment H-3D of PJM OATT	ER08-10, Incentive filing
3	Attachment H-3D of PJM OATT	ER08-686, Incentive filing
4	Attachment H-3D of PJM OATT	ER08-1423, Incentive filing
5	Attachment H-3D of PJM OATT	ER13-607, Incentive filing
6	Attachment H-3D of PJM OATT	EL13-48, ROE
7	Attachment H-3D of PJM OATT	ER19-6, FAS 109
8	Attachment H-3D of PJM OATT	ER20-2198, Transmission Formula Rate modification
9	Attachment H-3D of PJM OATT	ER20-1188, Material and Supplies (M&S)
10	Attachment H-3D of PJM OATT	ER21-2965, Transmission Wages and Salary (W&S) Allocator
11	Attachment H-3D of PJM OATT	ER22-2201, Transmission Depreciation Rates
12	Attachment H-3D of PJM OATT	ER25-141 Order No. 898 Rate Filing

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent)	Yes

filings containing the inputs to the formula rate(s)?	No

If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20240510-5128	05/10/2024	ER09-1158	Informational Filing of Annual Formula	

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1		Not Applicable		

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None

2. None

3. None

4. None

5. None

6. Refer to Note 10, "Debt and Credit Agreements" of the accompanying "Notes to the Financial Statements" and back schedule pages 256 - 257 for a discussion of DPL's debt. The authorizations for the issuances of long-term debt are Delaware Public Service Commission (DEPSC) order number 10143 and Maryland Public Service Commission (MDPSC) order number 90447. DPL has authorization from FERC to issue short-term debt securities in an amount not to exceed $500 million outstanding at any one time in docket ES24-2-000.

As of February 20, 2024, Exelon Corporation filed with the SEC a post-effective amendment to its shelf registration statement to remove and withdraw registration of all DPL's registered securities. DPL is listed as a co-registrant on the post-effective amendment and additionally filed the amendment to deregister all securities that remained unsold. DPL periodically issues securities through the private placement markets. DPL's ability to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, DPL's current financial condition, its securities ratings and market conditions.

7. None

8. None

9. Refer to Note 12, "Commitments and Contingencies" of the accompanying "Notes to Financial Statements" for a discussion of DPL's legal proceedings.

10. None

12. "Not Applicable"
13. See Officers page (Page 104) and Directors page (Page 105) for details concerning changes in the respondent's officers during 2024.
14. DPL participates in a cash management program. As of December 31, 2024, DPL's proprietary capital ratio is greater than 30 percent.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	7,388,692,148	6,787,512,529
3	Construction Work in Progress (107)	200	276,136,833	347,229,662
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,664,828,981	7,134,742,191
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	2,086,960,360	1,953,139,902
6	Net Utility Plant (Enter Total of line 4 less 5)		5,577,868,621	5,181,602,289
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202		
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)			
9	Nuclear Fuel Assemblies in Reactor (120.3)			
10	Spent Nuclear Fuel (120.4)			
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202		
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)			
14	Net Utility Plant (Enter Total of lines 6 and 13)		5,577,868,621	5,181,602,289
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		16,095,614	16,086,943
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,685,569	4,632,691
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		102,277	95,665
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)			
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			
31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		11,512,322	11,549,917
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		21,103,197	15,601,254
36	Special Deposits (132-134)		2,390,025	276,547
37	Working Fund (135)			

38	Temporary Cash Investments (136)		21,181	459,425
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		134,025,436	119,408,873
41	Other Accounts Receivable (143)		61,621,434	50,822,325
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		25,222,850	26,163,316
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		461,523	644,936
45	Fuel Stock (151)	227		
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	94,983,934	71,822,527
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	8,838,517	8,204,386
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		
55	Gas Stored Underground - Current (164.1)		5,757,962	7,842,295
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		700,548	1,012,622
57	Prepayments (165)		55,774,244	53,516,106
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		5,255	3,577
60	Rents Receivable (172)		1,138,380	1,117,010
61	Accrued Utility Revenues (173)		76,395,554	63,939,750
62	Miscellaneous Current and Accrued Assets (174)		1,740,174	1,563,816
63	Derivative Instrument Assets (175)			
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		439,734,514	370,072,133
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		16,833,093	16,360,028
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	155,990,560	161,267,909
73	Prelim. Survey and Investigation Charges (Electric) (183)			
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	121,424,957	138,352,496
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		2,560,733	3,173,835
82	Accumulated Deferred Income Taxes (190)	234	116,009,360	131,295,525
83	Unrecovered Purchased Gas Costs (191)			

84	Total Deferred Debits (lines 69 through 83)		412,818,703	450,449,793
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,441,934,160	6,013,674,132

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	2,250	2,250
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		537,612,396	537,612,396
7	Other Paid-In Capital (208-211)	253	1,086,562,642	926,561,747
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	9,924,450	9,924,450
11	Retained Earnings (215, 215.1, 216)	118	621,374,793	632,552,822
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(2,177,779)	(2,177,779)
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)		
16	Total Proprietary Capital (lines 2 through 15)		2,233,449,852	2,084,626,986
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	2,198,900,000	2,057,230,000
19	(Less) Reacquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	10,000,000	10,000,000
22	Unamortized Premium on Long-Term Debt (225)		638,791	658,328
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,133,456	1,176,211
24	Total Long-Term Debt (lines 18 through 23)		2,208,405,335	2,066,712,117
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		21,405,516	23,625,175
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		5,639,052	5,891,459
29	Accumulated Provision for Pensions and Benefits (228.3)		4,730,976	7,804,449
30	Accumulated Miscellaneous Operating Provisions (228.4)		430,113	
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		12,791,683	12,464,471
35	Total Other Noncurrent Liabilities (lines 26 through 34)		44,997,340	49,785,554
36	**CURRENT AND ACCRUED LIABILITIES**			

37	Notes Payable (231)		143,949,206	62,968,099
38	Accounts Payable (232)		161,194,646	123,108,151
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		26,326,106	25,370,348
41	Customer Deposits (235)		34,135,267	30,640,077
42	Taxes Accrued (236)	262	11,939,625	30,549,303
43	Interest Accrued (237)		15,880,352	13,322,596
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		588,646	554,751
48	Miscellaneous Current and Accrued Liabilities (242)		116,684,929	95,973,765
49	Obligations Under Capital Leases-Current (243)		6,348,604	5,771,061
50	Derivative Instrument Liabilities (244)			
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		517,047,381	388,258,151
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		58,410,506	31,911,415
57	Accumulated Deferred Investment Tax Credits (255)	266	642,368	833,420
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	27,233,314	28,842,636
60	Other Regulatory Liabilities (254)	278	291,157,204	328,455,425
61	Unamortized Gain on Reacquired Debt (257)			
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272		
63	Accum. Deferred Income Taxes-Other Property (282)		974,728,278	947,474,500
64	Accum. Deferred Income Taxes-Other (283)		85,862,582	86,773,928
65	Total Deferred Credits (lines 56 through 64)		1,438,034,252	1,424,291,324
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,441,934,160	6,013,674,132

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

Do not report fourth quarter data in columns (e) and (f)
Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of

such changes.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	1,792,911,606	1,691,509,804			1,612,917,944	1,485,715,865	179,993,662	205,793,939		
3	Operating Expenses											
4	Operation Expenses (401)	320	1,071,167,560	989,637,116			960,044,227	848,752,083	111,123,333	140,885,033		
5	Maintenance Expenses (402)	320	72,039,005	84,598,748			65,922,549	78,176,313	6,116,456	6,422,435		
6	Depreciation Expense (403)	336	187,589,733	191,230,055			173,377,675	177,554,069	14,212,058	13,675,986		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	24,334,842	24,953,776			22,628,151	22,417,686	1,706,691	2,536,090		
9	Amort. of Utility Plant Acq. Adj. (406)	336										
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)											
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		13,555,868	50,791,586			12,768,050	49,659,161	787,818	1,132,425		
13	(Less) Regulatory Credits (407.4)		(8,449,333)	6,299,333			(8,449,333)	6,299,333				
14	Taxes Other Than Income Taxes (408.1)	262	78,361,070	73,986,285			65,214,367	61,334,844	13,146,703	12,651,441		
15	Income Taxes - Federal (409.1)	262	27,015,891	25,511,096			22,454,749	20,870,661	4,561,142	4,640,435		
16	Income Taxes - Other (409.1)	262	4,341,507	6,655,943			3,366,243	5,414,910	975,264	1,241,033		
17	Provision for Deferred Income Taxes (410.1)	234, 272	64,242,662	60,493,622			57,281,018	54,177,962	6,961,644	6,315,660		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	47,210,612	55,984,780			41,240,690	48,136,322	5,969,922	7,848,458		
19	Investment Tax Credit Adj. - Net (411.4)	266	(191,052)	(250,954)			(177,018)	(228,265)	(14,034)	(22,689)		
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)											
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,503,695,807	1,445,323,160			1,350,088,654	1,263,693,769	153,607,153	181,629,391		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		289,215,799	246,186,644			262,829,290	222,022,096	26,386,509	24,164,548		
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		5,412,794	4,257,660								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		5,904,847	3,274,384								
33	Revenues From Nonutility Operations (417)		1,825,968									
34	(Less) Expenses of Nonutility Operations (417.1)		98,752	93,141								
35	Nonoperating Rental Income (418)		303,676	215,665								

36	Equity in Earnings of Subsidiary Companies (418.1)	119											
37	Interest and Dividend Income (419)		5,098,308	2,631,420									
38	Allowance for Other Funds Used During Construction (419.1)		11,777,950	10,338,511									
39	Miscellaneous Nonoperating Income (421)		4,584,444	2,619,167									
40	Gain on Disposition of Property (421.1)			740,718									
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		22,999,541	17,435,616									
42	Other Income Deductions												
43	Loss on Disposition of Property (421.2)		6,462										
44	Miscellaneous Amortization (425)												
45	Donations (426.1)		688,949	703,679									
46	Life Insurance (426.2)												
47	Penalties (426.3)		(83,580)	523,666									
48	Exp. for Certain Civic, Political & Related Activities (426.4)		845,555	721,699									
49	Other Deductions (426.5)		6,552,152	9,568,554									
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,009,538	11,517,598									
51	Taxes Applic. to Other Income and Deductions												
52	Taxes Other Than Income Taxes (408.2)	262	775,943	634,373									
53	Income Taxes-Federal (409.2)	262	2,155,574	754,071									
54	Income Taxes-Other (409.2)	262	156,436	(256,502)									
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	81,010	3,291									
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	1,618,805	1,770,317									
57	Investment Tax Credit Adj.-Net (411.5)												
58	(Less) Investment Tax Credits (420)												
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		1,550,158	(635,084)									
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		13,439,845	6,553,102									
61	Interest Charges												
62	Interest on Long-Term Debt (427)		94,535,709	76,901,060									
63	Amort. of Debt Disc. and Expense (428)		1,196,330	1,362,421									
64	Amortization of Loss on Reaquired Debt (428.1)		613,102	617,789									
65	(Less) Amort. of Premium on Debt-Credit (429)		19,537	467,676									
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)												
67	Interest on Debt to Assoc. Companies (430)		38,609	11,433									
68	Other Interest Expense (431)		4,315,882	3,437,358									
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		6,846,422	5,875,003									
70	Net Interest Charges (Total of lines 62 thru 69)		93,833,673	75,987,382									
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		208,821,971	176,752,364									
72	Extraordinary Items												
73	Extraordinary Income (434)												
74	(Less) Extraordinary Deductions (435)												

75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		208,821,971	176,752,364								

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		632,552,822	589,200,458
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		208,821,971	176,752,364
17	Appropriations of Retained Earnings (Acct. 436)			
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	Common Stock (Dividends paid to Parent)		(220,000,000)	(133,400,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(220,000,000)	(133,400,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		621,374,793	632,552,822
39	APPROPRIATED RETAINED EARNINGS (Account 215)			
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		621,374,793	632,552,822
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		(2,177,779)	(2,177,779)
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			

52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		(2,177,779)	(2,177,779)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	208,821,971	176,752,364
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	187,589,733	191,230,055
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of regulatory debits/credits and limited plant	58,414,512	52,316,289
5.2	Amortized Plant Acquisition Adjustment		
5.3	Unamortized Discount (Premium) on Long-Term Debt	1,735,768	1,205,784
8	Deferred Income Taxes (Net)	15,494,255	2,741,816
9	Investment Tax Credit Adjustment (Net)	(191,052)	(250,954)
10	Net (Increase) Decrease in Receivables	(38,651,577)	20,660,586
11	Net (Increase) Decrease in Inventory	(20,765,000)	(4,493,976)
12	Net (Increase) Decrease in Allowances Inventory	(634,131)	156,381
13	Net Increase (Decrease) in Payables and Accrued Expenses	18,929,029	(5,206,072)
14	Net (Increase) Decrease in Other Regulatory Assets	(28,820,653)	(8,057,441)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(11,163,879)	14,151,973
16	(Less) Allowance for Other Funds Used During Construction	11,777,950	10,338,511
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Pension	15,332,234	17,359,536
18.2	[(a)] Other Operating Activities	24,003,248	17,590,980
18.3	Net Increase (Decrease) in Interest and Taxes Accrued	(15,296,236)	27,588,806
18.4	(Gain) Loss on Sales of Assets	6,462	(720,026)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	403,026,734	492,687,590
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(567,359,039)	(572,549,219)
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	(11,777,950)	(10,338,511)
31	Other (provide details in footnote):		

31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(555,581,089)	(562,210,708)
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies		
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		
46	Loans Made or Purchased		
47	Collections on Loans		
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
53.1	Proceeds from sale of assets		
53.2	Change in PHI Intercompany Pool		
53.3	(b) Other Investing Activities	(3,127,281)	(3,498,026)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(558,708,370)	(565,708,734)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	175,000,000	650,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other : Contributions from Parent	160,000,895	98,308,342
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):	80,981,107	
67.2	Capital Contribution from Parent		
70	Cash Provided by Outside Sources (Total 61 thru 69)	415,982,002	748,308,342
72	Payments for Retirement of:		
73	Long-term Debt (b)	(33,330,000)	(500,000,000)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Cost of Issuances	(1,906,667)	(4,981,629)
78	Net Decrease in Short-Term Debt (c)		(51,941,169)
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(220,000,000)	(133,400,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	160,745,335	57,985,544
85	Net Increase (Decrease) in Cash and Cash Equivalents		

86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	5,063,699	(15,035,600)
88	Cash and Cash Equivalents at Beginning of Period	16,060,679	31,096,279
90	Cash and Cash Equivalents at End of Period	21,124,378	16,060,679

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivitiesDescription

Other Operating Activities:

	2024	2023
Net increases in Prepayments	$ (2,258,138)	$ (2,845,688)
Net decrease (increase) in Miscellaneous long term assets and deferred debits	1,675,180	(1,014,181)
Net (decrease) increase in Other deferred credits	(1,609,322)	2,426,709
Principal Portion of Capital Lease Payments	(6,764,983)	(6,099,963)
Net (increase) decrease in Special Deposits	(2,113,478)	120,481,113
Net (decrease) increase in Short-term Contract Liabilities	(446,264)	384,243
Net increase (decrease) in Collateral received, net	2,113,478	(120,481,239)
Net increases in Customer Advances for Construction	26,499,091	16,370,456
Other	6,907,684	8,369,530
Total Other Operating Activities	$ 24,003,248	$ 17,590,980

(b) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivitiesDescription

Other Investing Activities:

	2024	2023
Cloud Computing Arrangements	$ (4,596,681)	$ (4,026,568)
Other	1,469,400	528,542
Total Other Investing Activities	$ (3,127,281)	$ (3,498,026)

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

The notes presented herein were derived from the notes disclosed within the Annual Report of Exelon Corporation (Exelon) Form 10-K for the fiscal year ended December 31, 2024. The notes presented herein were modified to include information relevant to Delmarva Power & Light Company (DPL). All amounts presented within the footnotes are rounded in millions unless otherwise noted.

1. Significant Accounting Policies

Description of Business

DPL is engaged in the purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in portions of New Castle County in Delaware.

Revision of Previously Issued Financial Statements

In the fourth quarter of 2024, management identified an error related to the recording of REC obligations in Maryland, and the corresponding Prepaid environmental credits, which were incorrectly netted on the Balance Sheet rather than reflected on a gross basis. As a result of this error, the Prepaid environmental credits and the REC obligations were understated on the the Balance Sheet of DPL as of December 31, 2023 by $27 million. There was no impact on the Statement of Income, Statement of Cash Flows, or Statement of Retained Earnings for the years ended December 31, 2023 or December 31, 2022.

Management has concluded that the error was not material to previously issued financial statements for DPL. The Balance Sheet as of December 31, 2023 for DPL was revised to reflect the correction of the error.

Basis of Presentation

DPL is an indirect, wholly owned, subsidiary of Exelon.

Accounting policies for regulated operations are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the DEPSC, MDPSC, and FERC. The accompanying financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts (USOA) and accounting releases, which differ from accounting principles generally accepted in the United States of America (GAAP). The principal differences from GAAP include the exclusions of current maturities of long-term debt from current liabilities, the exclusion of debt issuance costs from long-term debt, the exclusion of restricted cash within cash and cash equivalents in the Statement of Cash Flows, the requirement to report deferred tax assets and liabilities separately rather than as a single amount, the classification of accrued taxes as assets and liabilities rather than a net amount, the exclusion of FIN 48 liabilities related to temporary income tax differences, the derecognition of operating leases from the balance sheet, the classification of cloud computing costs, and the classification of certain other assets and liabilities as current instead of noncurrent.

Use of Estimates

The preparation of financial statements in conformity with USOA requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for pension and other postretirement employee benefits (OPEB), unbilled energy revenues, accumulated provision for uncollectible accounts, inventory reserves, asset impairment assessments, derivative instruments, fixed asset depreciation, capitalization of indirect construction costs, environmental costs and other loss contingencies, asset retirement obligations (AROs), and income taxes. Actual results could differ from those estimates.

Regulatory Accounting

For its regulated electric and gas operations, DPL reflects the effects of cost-based rate regulation in its financial statements, which is required for entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. DPL accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the MDPSC and the DEPSC, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the Statement of Income consistent with the recovery or refund included in customer rates. DPL's regulatory assets and liabilities as of the balance sheet date are probable of being recovered or settled in future rates. If a separable portion of DPL's business was no longer able to meet the criteria discussed above, DPL would be required to eliminate from its financial statements the effects of

regulation for that portion, which could have a material impact on its financial statements. See Note 2 - Regulatory Matters for additional information.

DPL treats the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues

Operating Revenues. DPL's operating revenues generally consist of revenues from contracts with customers involving the sale and delivery of power and utility revenues from alternative revenue programs (ARP). DPL recognizes revenue from contracts with customers to depict the transfer of goods or services to customers in an amount that the entities expect to be entitled to in exchange for those goods or services. DPL's primary sources of revenue include regulated electric and natural gas tariff sales, distribution and transmission services. At the end of each month, DPL accrues an estimate for the unbilled amount of energy delivered or services provided to customers.

DPL records ARP revenue for its best estimate of the electric distribution revenue impacts resulting from future changes in rates that it believes are probable of approval by the MDPSC in accordance with its revenue decoupling mechanisms. DPL records ARP revenue for its best estimate of the transmission revenue impacts resulting from future changes in rates that it believes are probable of approval by FERC in accordance with its formula rate mechanisms. DPL recognizes all ARP revenues that will be collected within 24 months of the end of the annual period in which they are recorded. See Note 2 - Regulatory Matters for additional information.

Taxes Directly Imposed on Revenue-Producing Transactions. DPL collects certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees, that are levied by state or local governments on the sale or distribution of electricity and gas. Some of these taxes are imposed on the customer, but paid by DPL, while others are imposed on DPL. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Statement of Income. However, where these taxes are imposed on DPL, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 14 - Supplemental Financial Information for DPL's taxes that are presented on a gross basis.

Income Taxes

Deferred federal and state income taxes are recorded on significant temporary differences between the book and tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred in DPL's Balance Sheets and are recognized in book income over the life of the related property. DPL accounts for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. DPL recognizes accrued interest related to unrecognized tax benefits in Interest expense, net or Other, net (interest income) and recognize penalties related to unrecognized tax benefits in Other, net in its Statement of Income.

Cash and Cash Equivalents

DPL considers investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2024 and 2023, DPL's restricted cash and cash equivalents primarily represented funds restricted for the collateral held from energy suppliers.

Accumulated Provision for Uncollectible Accounts on Customer Receivables

The accumulated provisions for uncollectible accounts reflects DPL's best estimates of losses on the customers' accounts receivable balances based on historical experience, current information, and reasonable and supportable forecasts.

The accumulated provisions for uncollectible accounts for DPL's customers is estimated based on historical experience, current conditions, and forward-looking risks factors. DPL's customer accounts are written off consistent with approved regulatory requirements. Adjustments to the accumulated provisions for uncollectible accounts are primarily recorded to

Operating and maintenance expense on DPL's Statement of Income or Regulatory assets and liabilities on DPL's Balance Sheet. See Note 2 - Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts on customer accounts receivable at DPL.

DPL has certain non-customer receivables in Other deferred debits and other assets which primarily are with governmental agencies and other high-quality counterparties with no history of default. As such, the allowance for uncollectible accounts related to these receivables is not material. DPL monitors these balances and will record an allowance if there are indicators of a decline in credit quality. See Note 4 - Accounts Receivable for additional information.

Inventories

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory. Fossil fuel and materials and supplies are generally included in inventory when purchased. Fossil fuel is expensed to Purchased power and fuel expense when used or sold. Materials and supplies generally includes transmission and distribution materials and are expensed to Operating and maintenance or capitalized to Property, plant, and equipment, as appropriate, when installed or used.

Property, Plant, and Equipment

Property, plant, and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs and indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes allowance for funds used during construction (AFUDC) for regulated property. The cost of repairs and maintenance and minor replacements of property is charged to Operating and maintenance expense as incurred.

Third parties reimburse DPL for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, plant, and equipment, net.

Upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation consistent with the composite and group methods of depreciation. Depreciation expense at DPL includes the estimated cost of dismantling and removing plant from service upon retirement. Actual incurred removal costs are applied against a related regulatory liability or recorded to a regulatory asset if in excess of previously collected removal costs.

Capitalized Software. Certain costs, such as design, coding, and testing incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized within Property, plant, and equipment. Similar costs incurred for cloud-based solutions treated as service arrangements are capitalized within Property, plant, and equipment. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements.

Allowance for Funds Used During Construction (AFUDC). AFUDC is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to an allowance that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

See Note 5 - Property, Plant, and Equipment for additional information.

Depreciation and Amortization

Depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the group or composite methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for dissimilar assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. DPL's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with its regulatory recovery method. The estimated service lives for DPL are based on a combination of depreciation studies and historical retirements.

See Note 5 - Property, Plant, and Equipment for further information regarding depreciation.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory order or agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would have originally been recorded in DPL's Statement of Income. Amortization of DPL's transmission formula rate regulatory assets is recorded to Operating revenues.

Amortization of income tax related regulatory assets and liabilities is generally recorded to Income tax expense. Except for the regulatory assets and liabilities discussed above, amortization is generally recorded to Depreciation and amortization in DPL's Statement of Income when the recovery period is more than one year.

See Note 2 - Regulatory Matters for additional information regarding the amortization of DPL's regulatory assets and liabilities.

Asset Retirement Obligations

DPL estimates and recognizes a liability for its legal obligation to perform asset retirement activities even though the timing and/or methods of settlement may be conditional on future events. DPL updates their AROs either annually or on a rotational basis at least once every three years, based on a risk profile, unless circumstances warrant more frequent updates. The updates factor in new cost estimates, credit-adjusted, risk-free rates (CARFR) and escalation rates and the timing of cash flows. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through an increase to regulatory assets. See Note 6 - Asset Retirement Obligations for additional information.

Guarantees

If necessary, DPL recognizes a liability at the time of issuance of a guarantee for the fair value of the obligations they have undertaken. The liability is reduced or eliminated as DPL is released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of DPL may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 12 - Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets. DPL evaluates the carrying value of long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include specific regulatory disallowance, abandonment, or plans to dispose of a long-lived asset significantly before the end of its useful life. When the estimated undiscounted future cash flows attributable to the long-lived asset may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its fair value.

Derivative Financial Instruments

Derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales (NPNS) exception. For derivatives that qualify and are designated as cash flow hedges, changes in fair value each period are initially recorded in Accumulated other comprehensive income (AOCI) and recognized in earnings when the underlying hedged transaction affects earnings. Amounts recognized in earnings are recorded in Interest expense, net on DPL's Statement of Income based on the activity the transaction is economically hedging. Cash inflows and outflows related to derivative instruments designated as cash flow hedges are included as a component of operating, investing or financing cash flows in the Statement of Cash Flows, depending on the nature of each transaction.

For derivatives intended to serve as economic hedges, which are not designated for hedge accounting, changes in fair value each period are recognized in earnings or as a regulatory asset or liability each period. Amounts recognized in earnings are recorded in Electric operating revenues, Purchased power and fuel, or Interest expense in the Statement of Income based on the activity the transaction is economically hedging. Changes in fair value are also recorded as a regulatory asset or liability when there is an ability to recover or return the associated costs or benefits in accordance with regulatory requirements. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing, or financing cash flows in the Statement of Cash Flows, depending on the nature of the hedged item. See Note 2 - Regulatory Matters and Note 9 - Derivative Financial Instruments for additional information.

Retirement Benefits

DPL participates in Exelon's defined benefit pension plans and OPEB plans.

The plan obligations and costs of providing benefits under these plans are measured as of December 31. The measurement involves various factors, assumptions, and accounting elections. The impact of assumption changes or experiences different from those assumed on pension and OPEB obligations is recognized over time rather than immediately recognized in the Statement of Income. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the market related value (MRV) of plan assets are amortized over the expected average remaining service period of plan participants. See Note 8 - Retirement Benefits for additional information.

New Accounting Pronouncements

New Accounting Standards Issued and Not Yet Adopted as of December 31, 2024

The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by DPL in their financial statements as of December 31, 2024. Unless otherwise indicated, DPL is currently assessing the impacts such guidance may have (which could be material) in their Balance Sheet, Statement of Income, Statement of Cash Flows and disclosures, as well as the potential to early adopt where applicable. DPL has assessed other FASB issuances of new standards which are not listed below given the current expectation that such standards will not significantly impact DPL's financial reporting.

Improvement to Income Tax Disclosures (Issued December 2023). Provides additional disclosure requirements related to the effective tax rate reconciliation and income taxes paid. Under the revised guidance for the effective tax reconciliations, entities would be required to disclose: (1) eight specific categories in the effective tax rate reconciliation in both percentages and reporting currency amount, (2) additional information for reconciling items over a certain threshold, (3) explanation of individual reconciling items disclosed, and (4) provide a qualitative description of the state and local jurisdictions that contribute to the majority of the state income tax expense. For each annual period presented, the new standard requires disclosure of the year-to-date amount of income taxes paid (net of refunds received) disaggregated by federal, state, and foreign. It also requires additional disaggregated information on income taxes paid (net of refunds received) to an individual jurisdiction equal to or greater than 5% of total income taxes paid (net of refunds received). The standard is effective January 1, 2025, with early adoption permitted.

Disaggregation of Income Statement Expenses (Issued November 2024). Provides additional disclosure requirements related to relevant expense captions of income statement expense line items. The revised guidance requires a new tabular disclosure of disaggregated income statement expenses including a break out of (1) purchases of inventory, (2) employee compensation, (3) depreciation, (4) intangible asset amortization, (5) depreciation, depletion, and amortization recognized as part of oil and gas producing activities included in each relevant expense line item on the income statement. The tabular disaggregation should include certain amounts already required to be disclosed under GAAP elsewhere. Any remaining amounts not separately disaggregated quantitatively should include a qualitative description. Additionally, on an annual basis, the standard requires disclosure of management's definition of selling expenses and the amount of expense. The standard is effective January 1, 2027, with early adoption permitted. DPL is currently assessing the impacts of this standard.

2. Regulatory Matters

The following matters below discuss the status of material regulatory and legislative proceedings of DPL.

Distribution Base Rate Case Proceedings

The following tables show the completed and pending distribution base rate case proceedings in 2024.

Completed Distribution Base Rate Case Proceedings

Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
Maryland[(a)]	May 19, 2022	Electric	$ 38	$ 29	9.60%	December 14, 2022	January 1, 2023
Delaware[(b)]	December 15, 2022 (amended September 29, 2023)	Electric	$ 39	$ 28	9.60%	April 18, 2024	July 15, 2023

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(a) Reflects a three-year cumulative multi-year plan for January 1, 2023 through December 31, 2025. The MDPSC awarded DPL electric incremental revenue requirement increases of $17 million, $6 million, and $6 million for 2023, 2024, and 2025, respectively.
(b) On April 18, 2024, the DEPSC approved the Significant Storm Expense Rate Rider (Rider SSER) which will allow DPL to recover expenses associated with qualified storms. A qualified storm will be an individual storm for which DPL incurs expenses between $5 million and $15 million. The Rider SSER allows DPL to recover significant storm damage expenses for the previous 12-month period over a future 24-month period. For individual storm events for which DPL incurs expenses of more than $15 million, the future recovery period will be evaluated on a case-by-case basis and the unamortized balance will earn a return at DPL's authorized long-term cost of debt. The Rider SSER will have an annual true-up filing, subject to DEPSC review and approval.

Pending Distribution Base Rate Case Proceedings

Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
Delaware[(a)]	September 20, 2024	Natural Gas	$ 36	10.65%	First quarter of 2026

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(a) DPL can implement interim rates on April 20, 2025, subject to refund.

Transmission Formula Rates

DPL's transmission rate is established based on a FERC-approved formula. DPL is required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rate effective on June 1 of the same year. The annual update is based on prior year actual costs and current year projected capital additions, accumulated depreciation, Depreciation and amortization expense, and accumulated deferred income taxes. The update also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2024, the following increases/(decreases) were included in DPL's electric transmission formula rate update:

Filing Date[(a)]	Initial Revenue Requirement Increase	Annual Reconciliation Decrease	Total Revenue Requirement Increase	Allowed Return on Rate Base[(b)]	Allowed ROE[(c)]
May 10, 2024	$ 7	$ 17	$ 24	7.23 %	10.50 %

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(a) Rate is effective June 1, 2024 - May 31, 2025, subject to review by interested parties pursuant to review protocols of DPL's tariff.
(b) Represents the weighted average debt and equity return on transmission rate bases.
(c) The rate of return on common equity for DPL includes a 50-basis-point incentive adder for being a member of a Regional Transmission Organization (RTO).

Other State Regulatory Matters

Maryland Regulatory Matters

Maryland Revenue Decoupling. In 2007, the MDPSC approved BSAs for DPL, which are decoupling mechanisms. As a result of the decoupling mechanisms, certain Operating revenues from electric distribution are not intended to be impacted by abnormal weather or usage per customer. The decoupling mechanism eliminates the impacts of abnormal weather or customer usage by recognizing revenues based on an authorized distribution amount per customer by customer class. Operating revenues from electric distribution are, however, impacted by changes in the number of customers.

EmPOWER Maryland Cost Recovery. On December 29, 2023, the MDPSC issued an order authorizing the next three-year program cycle for EmPOWER Maryland and approved various proposals by the program administrators to implement new energy efficiency programs for the 2024-2026 program cycle, as well as continue operating core programs. Historically, DPL deferred most of its energy efficiency program costs to a regulatory asset and either deferred most of its demand response program costs to a regulatory asset or capitalized them. Beginning in 2024, DPL will begin deferring less energy efficiency and demand response program costs to a regulatory asset. Additionally, as part of the order, the MDPSC directed DPL to extend the amortization of unamortized costs as of December 31, 2023 from 5 to 7 years to mitigate customer bill impacts.

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of DPL at December 31, 2024 and 2023:

Regulatory Assets (Account 182.3)	December 31, 2024	December 31, 2023
Advanced Metering Infrastructure (AMI) programs - deployment costs	$ 13	$ 17
AMI programs - legacy meters	10	14
Asset retirement obligations	4	3
COVID-19	3	6
Deferred storm costs	1	1
Electric energy and natural gas costs	24	4
Energy efficiency and demand response programs	78	75
Transmission formula rate annual reconciliations	12	22
Other	11	19
Total regulatory assets	$ 156	$ 161

Regulatory Liabilities (Account 254)	December 31, 2024	December 31, 2023
COVID-19	$ 1	$ 3
Deferred income taxes	247	273
Electric energy and natural gas costs	10	16
Multi-year plan reconciliations	9	7
Over-recovered revenue decoupling	2	2
Other	22	27
Total regulatory liabilities	$ 291	$ 328

Descriptions of the regulatory assets and liabilities included in the tables above are summarized below, including their recovery and amortization periods.

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
AMI programs - deployment costs	Represents installation and ongoing incremental costs of new smart meters, including implementation costs of dynamic pricing for energy usage resulting from smart meters.	2030	Yes
AMI programs - legacy meters	Represents early retirement costs of legacy meters.	2030	Delaware - Yes Maryland - No
Asset retirement obligations	Represents future legally required removal costs associated with existing AROs.	Over the life of the related assets.	Yes, once the removal activities have been performed
COVID-19	Represents incremental credit losses and direct costs related to COVID-19 incurred primarily in 2020, partially offset by a decrease in travel costs. Direct costs consisted primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of employees.	Maryland - $1 million - 2027 Delaware - $2 million - 2028.	Maryland - Yes Delaware - No
Deferred income taxes	Represents deferred income taxes that are recoverable or refundable through customer rates, primarily associated with accelerated depreciation, the equity component of AFUDC, and the effects of income tax rate changes, including those resulting from the TCJA.	Amounts are recoverable over the period in which the related deferred income taxes reverse, which is generally based on the expected life of the underlying assets. For TCJA, generally refunded over the remaining depreciable life of the underlying assets, except in certain jurisdictions where the commissions have approved a shorter refund period for certain assets not subject to IRS normalization rules.	No
Deferred storm costs	Amounts represent total incremental storm restoration costs incurred due to major storm events recoverable from customers in the Maryland jurisdiction.	2027	Yes
Electric energy and natural gas costs	Represents under (over)-recoveries related to energy and gas supply related costs recoverable (refundable) under approved rate riders.	2025	Delaware - Yes Maryland - No
Energy efficiency and demand response programs	Includes under recoveries of costs incurred related to energy efficiency programs and demand response programs and recoverable costs associated with customer direct load control and energy efficiency and conservation programs that are being recovered from customers.	2030	Maryland - See above regarding **EmPOWER Maryland Cost Recovery** for additional information Delaware - Yes
Multi-year plan reconciliations	Represents (over)-recoveries related to electric distribution multi-year plans.	Maryland - $5 million related to 2023 reconciliation - 2025.$4 million related to 2024 reconciliation to be determined in a future MDPSC order.	Maryland - Yes
Transmission formula rate annual reconciliations	Represents under (over)-recoveries related to transmission service costs recoverable through DPL's FERC formula rates, which are updated annually with rates effective each June 1st.	2026	Yes
Under (over) -recovered revenue decoupling	Represents electric and / or gas distribution costs recoverable from or refundable to customers under decoupling mechanisms.	2025	No

Capitalized Ratemaking Amounts Not Recognized

As of December 31, 2024 and 2023, DPL had $1 million and $1 million of authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment on its AMI program and Energy efficiency and demand response programs that were not recognized for financial reporting purposes on the Balance Sheet. These amounts will be recognized as revenues in the Statement of Income in the periods they are billable to customers.

3. Revenue from Contracts with Customers

DPL recognizes revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that it expects to be entitled to in exchange for those goods or services. DPL's primary sources of revenue include regulated electric and gas tariff sales, distribution, and transmission services. The performance obligations, revenue recognition and payment terms associated with these sources of revenue are further discussed in the table below. There are no significant financing components for these sources of revenue and no variable consideration.

Unless otherwise noted, for each of the significant revenue categories and related performance obligations described below, DPL has the right to consideration from the customer in an amount that corresponds directly with the value transferred to the customer for the performance completed to date. Therefore, DPL generally recognizes revenue in the amount for which it has the right to invoice the customer. As a result, there are generally no significant judgments used in determining or allocating the transaction price.

Revenue Source	Description	Performance Obligation	Timing of Revenue Recognition	Payment Terms
Regulated Electric and Gas Tariff Sales	Sales of electricity and electricity distribution services and natural gas and gas distribution services to residential, commercial, industrial and governmental customers through regulated tariff rates approved by state regulatory commissions.	Delivery of electricity and/or natural gas.	Over time (each day) as the electricity and/or natural gas is delivered to customers. Tariff sales are generally considered daily contracts as customers can discontinue service at any time.[(a)]	Within the month following delivery of the electricity or natural gas to the customer.
Regulated Transmission Services	DPL provides open access to its transmission facilities to PJM Interconnection, LLC ("PJM"), which directs and controls the operation of these transmission facilities and accordingly compensates DPL pursuant to filed tariffs at cost-based rates approved by FERC.	Various including (i) Network Integration Transmission Services (NITS), (ii) scheduling, system control and dispatch services, and (iii) access to the wholesale grid.	Over time utilizing output methods to measure progress towards completion.[(b)]	Paid weekly by PJM.

(a) Electric and natural gas utility customers have the choice to purchase electricity or natural gas from competitive electric generation and natural gas suppliers. While DPL is required under state legislation to bill its customers for the supply and distribution of electricity and/or natural gas, DPL recognizes revenue related only to the distribution services when customers purchase their electricity or natural gas from competitive suppliers.
(b) Passage of time is used for NITS and access to the wholesale grid and MWhs of energy transported over the wholesale grid is used for scheduling, system control and dispatch services.

DPL does not incur any material costs to obtain or fulfill contracts with customers.

Contract Liabilities

DPL records contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. DPL records contract liabilities within Miscellaneous Current and Accrued Liabilities (Account 242) and Other Deferred Credits (Account 253) within DPL's Balance Sheet.

On July 1, 2020, DPL entered into a collaborative arrangement ("Agreement") with an unrelated owner and manager of communication infrastructure (the "Buyer"). Under this arrangement, DPL sold a 60% undivided interest in its portfolio of transmission tower attachment agreements with telecommunications companies to the Buyer, in addition to transitioning management of the day-to-day operations of the jointly-owned agreements to the Buyer for 35 years, while retaining the safe and reliable operation of its utility assets. In return, DPL will provide the Buyer limited access on the portion of the towers where the equipment resides for the purposes of managing the agreements for the benefit of DPL and the Buyer. Pursuant to the Agreement, DPL has the option ("Payment Option"), but not obligation, to sell two additional 10% undivided interests in the

tower attachment agreements to the Buyer for specified consideration. In addition, for an initial period of three years and two, two-year extensions that are subject to certain conditions, the Buyer has the exclusive right to enter into new agreements with telecommunications companies and to receive a specified undivided percentage interest in those new agreements as set forth in the Agreement. DPL received cash and recorded contract liabilities as of July 1, 2020. The revenue attributable to this arrangement will be recognized as Electric operating revenues over the 35 years under the Agreement.

During the fourth quarter of 2023, DPL entered into an amendment to the Agreement ("Amendment") to modify the terms of the Payment Option and the conditions to exercise the exclusive right extensions. Concurrently DPL exercised both Payment Options which also triggered the extension of the exclusive right period until 2027. The Amendment and executed Payment Options represent a contract modification that is accounted for prospectively in accordance with authoritative guidance. DPL received cash and recorded an increase to the contract liabilities as of December 31, 2023 as shown in the table below. The revenue will be recognized as Electric operating revenues over the remaining term of the Agreement (approximately 31 years from the Amendment date).

The following table provides a rollforward of the contract liabilities reflected in DPL's Balance Sheet as of December 31, 2024 and 2023.

Balance at December 31, 2022	$	10
Consideration received or due		4
Revenues recognized[(a)]		(1)
Balance at December 31, 2023		13
Revenues recognized		—
Balance at December 31, 2024	$	13

(a) Revenue recognized in the year ended December 31, 2023, was included in the contract liabilities at December 31, 2022.

Transaction Price Allocated to Remaining Performance Obligations

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of December 31, 2024. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years.

This disclosure excludes the Utility Registrants' gas and electric tariff sales contracts and transmission revenue contracts as they generally have an original expected duration of one year or less and, therefore, do not contain any future, unsatisfied performance obligations to be included in this disclosure.

2025	2026	2027	2028	2029 and thereafter	Total
$ 1	$ 1	$ —	$ —	$ 11	$ 13

4. Account Receivable

Accumulated Provision for Uncollectible Accounts

The following tables present the rollforward of Accumulated Provision for Uncollectible Accounts on Customer Accounts Receivable (Account 144).

		For the Year Ended December 31, 2024
Balance at December 31, 2023	$	19
Plus: Current period provision (benefit) for uncollectible accounts		9
Less: Write-offs, net of recoveries[(a)]		12
Balance at December 31, 2024	$	16

		For the Year Ended December 31, 2023
Balance at December 31, 2022	$	21
Plus: Current period provision (benefit) for uncollectible accounts		9
Less: Write-offs, net of recoveries		11
Balance at December 31, 2023	$	19

(a) Recoveries were not material to DPL.

The following tables present the rollforward of Accumulated Provision for Uncollectible Accounts on Other Accounts Receivable (Account 144).

		For the Year Ended December 31, 2024
Balance at December 31, 2023	$	8
Plus: Current period provision (benefit) for uncollectible accounts		1
Less: Write-offs, net of recoveries[(a)]		—
Balance at December 31, 2024	$	9

		For the Year Ended December 31, 2023
Balance at December 31, 2022	$	7
Plus: Current period provision (benefit) for uncollectible accounts		1
Less: Write-offs, net of recoveries		—
Balance at December 31, 2023	$	8

(a) Recoveries were not material to DPL.

Accrued Utility Revenues

DPL accrued $76 million and $64 million of unbilled revenues as of December 31, 2024 and December 31, 2023, respectively, in Accrued Utility Revenues (Account 173).

Purchase of Customer and Other Accounts Receivable

For the twelve months ended December 31, 2024 and 2023, DPL was required, under legislation and regulations in Maryland, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participated in its consolidated billing. The following table presents the total receivables DPL purchased:

	For the Years Ended December 31,	
	2024	2023
Total receivables purchased	$ 252	$ 228

5. Property, Plant, and Equipment

The following table presents the average service life for each asset category in number of years:

Asset Category	Average Service Life (years)
Electric - transmission and distribution	3-75
Gas - transportation and distribution	3-75
Common - electric and gas	5-75
Other property, plant and equipment	10-43

The following table presents the annual depreciation rates for each asset category:

Annual Depreciation Rates	December 31, 2024	December 31, 2023
Electric - transmission and distribution	3.03 %	3.32 %
Gas - transportation and distribution	1.38 %	1.44 %
Common - electric and gas	6.14 %	8.79 %

The credits to AFUDC debt and equity were $19 million and $16 million for the years ended December 31, 2024 and 2023, respectively.

DPL's undivided ownership interests in jointly owned transmission facilities with non-affiliated utilities as of December 31, 2024 and 2023 were as follows:

Operator		**PSEG/DPL**
DPL's share at December 31, 2024		NJ/DE[a]
Plant in service	$	3
Accumulated depreciation		2
Construction work in progress		—
DPL's share at December 31, 2023		NJ/DE[a]
Plant in service	$	3
Accumulated depreciation		2
Construction work in progress		—

(a) DPL owns a 1% share in 151.3 miles of 500kV lines located in New Jersey and of the Salem generating plant substation. DPL also owns a 7.45% share in 2.5 miles of 500kV line located over the Delaware River.

Certain facilities are fully owned by Exelon through its 100% ownership in DPL and other wholly owned subsidiaries. These facilities are operated by Exelon wholly owned subsidiaries. DPL's material undivided ownership interests in Exelon owned facilities as of December 31, 2024 and 2023 were as follows:

Ownership interest		27 %
DPL's share at December 31, 2024		
Plant in service	$	44
Accumulated depreciation		3
Construction work in progress		—
DPL's share at December 31, 2023		
Plant in service	$	4
Accumulated depreciation		—
Construction work in progress		36

DPL's undivided ownership interests in jointly owned plants presented in the tables above, are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. DPL's share of direct expenses is included in operating and maintenance expenses on DPL's Statements of Income.

Refer to Note 1 - Significant Accounting Policies for additional information regarding property, plant and equipment policies and Note 10 - Debt and Credit Agreements for additional information regarding DPL's property, plant, and equipment subject to mortgage liens.

6. Asset Retirement Obligations

DPL has AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and Polychlorinated Biphenyl. See Note 1 - Significant Accounting Policies for additional information on DPL's accounting policy for AROs.

The following table provides a rollforward of the AROs reflected on DPL's Comparative Balance Sheet from December 31, 2022 to December 31, 2024:

AROs at December 31, 2022 (Account 230)	$	13
Revisions in estimates of cash flows		(1)
Accretion expense[a]		1
AROs at December 31, 2023 (Account 230)		13
Revisions in estimates of cash flows		—
Accretion expense[a]		—
AROs at December 31, 2024 (Account 230)	$	13

(a) The majority of the accretion expense is recorded as an increase to a regulatory asset due to the associated regulatory treatment.

7. Income Taxes

Components of Income Tax Expense or Benefit

Income tax expense (benefit) from continuing operations is comprised of the following components:

	For the Years Ended December 31, 2024		For the Years Ended December 31, 2023	
Included in operations:				
Federal				
Current	$	29	$	25
Deferred		3		(6)
State				
Current		4		6
Deferred		13		10
Total (Accounts 409.1, 409.2, 410.1, 411.1, 411.4)	$	49	$	35

Rate Reconciliation

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

	For the Years Ended December 31, 2024[a]	For the Years Ended December 31, 2023[a]
U.S. Federal statutory rate	21.0 %	21.0 %
Increase (decrease) due to:		
State income taxes, net of Federal income tax benefit	5.2	6.1
Plant Basis differences	(1.1)	(0.7)
Excess deferred tax amortization	(5.6)	(9.4)
Amortization of investment tax credit, including deferred taxes on basis differences	(0.1)	(0.1)
Tax credits	(0.4)	(0.4)
Other	—	—
Effective income tax rate	19.0 %	16.5 %

(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.

Tax Differences and Carryforwards

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2024 and 2023 are presented below:

	At December 31, 2024		At December 31, 2023	
Plant basis differences	$	(975)	$	(947)
Deferred pension and postretirement obligation		(32)		(35)
Deferred debt refinancing costs		(1)		(2)
Regulatory assets and liabilities		33		45
Tax loss carryforward, net of valuation allowances		16		18
Corporate Alternative Minimum Tax		4		2
Other, net		10		16
Deferred income tax liabilities, net (Accounts 190, 282, 283)		(945)		(903)
Unamortized investment tax credits (Account 255)		(1)		(1)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$	(946)	$	(904)

The following table provides DPL's federal and state carryforwards, which are presented on a post-apportioned basis and corresponding valuation allowances as of December 31, 2024.

Corporate Alternative Minimum Tax credit carryforward	$	4
State net operating losses and other carryforwards		670
Deferred taxes on state tax attributes (net of federal taxes)[a]		45

Valuation allowance on state tax attributes (net of federal taxes)	29
Year in which net operating loss or credit carryforwards will begin to expire[(b)]	2033

(a) A full valuation allowance has been recorded against Delaware net operating losses carryforwards due to a change in Delaware tax law that restricts the ability for corporate taxpayers to monetize net operating losses.
(b) A portion of the Maryland state net operating loss carryforward have an indefinite carryforward period.

Tabular Reconciliation of Unrecognized Tax Benefits

The following table presents changes in unrecognized tax benefits for DPL:

Balance at January 1, 2022	$ 3
Change to positions that only affect timing	1
Balance at December 31, 2022	4
Change to positions that only affect timing	(2)
Balance at December 31, 2023	2
Change to positions that only affect timing	10
Balance at December 31, 2024	$ 12

Recognition of unrecognized tax benefits

The following table represents DPL's unrecognized tax benefits that, if recognized, would decrease the effective tax rate.

December 31, 2024	$ 1
December 31, 2023	1
December 31, 2022	—

Unrecognized tax benefits for which significant increases or decreases are possible within 12 months after the reporting date

At December 31, 2024, DPL has $0 of unrecognized tax benefits that could significantly decrease within the 12 months after the reporting date based on the outcome of pending court cases involving other taxpayers.

Total amounts of interest and penalties recognized

DPL's net interest and penalties receivable (payable) related to tax positions are not material as of December 31, 2024 and 2023.

DPL's interest and penalty expense related to tax positions are not material at both December 31, 2024 and 2023.

Description of tax years that remain open to assessment by major jurisdiction

	Open Years
Federal consolidated income tax returns[(a)]	2010-2023
Delaware separate corporate income tax returns	Same as federal
Maryland separate company corporate net income tax returns	Same as federal

(a) DPL is only open to assessment for tax years since joining the Exelon federal consolidated group, beginning in 2016.

Other Tax Matters

Corporate Alternative Minimum Tax

On August 16, 2022, the IRA was signed into law and implemented a new corporate alternative minimum tax (CAMT) that imposes a 15.0% tax on modified GAAP net income. Corporations are entitled to a tax credit (minimum tax credit) to the extent the CAMT liability exceeds the regular tax liability. This amount can be carried forward indefinitely and used in future years when regular tax exceeds the CAMT.

Beginning in 2023, based on the existing statute, DPL will be subject to and will report the CAMT on a separate Registrant basis. The deferred tax asset related to the minimum tax credit carryforward will be realized to the extent DPL's deferred tax liabilities exceed the minimum tax credit carryforward. DPL's deferred tax liabilities are expected to exceed the minimum tax credit carryforward to the foreseeable future and thus no valuation allowance is required.

On September 12, 2024, the U.S Treasury issued proposed regulations providing further guidance addressing the implementation of CAMT. The proposed regulations are consistent with Exelon's prior interpretation and therefore there are no financial statement impacts. DPL will continue to monitor and assess the potential financial statement impacts of final regulations or other guidance when issued.

Long-Term Marginal State Income Tax Rate

Quarterly, Exelon reviews and updates its marginal state income tax rates for material changes in state tax laws and state apportionment. DPL remeasures its existing deferred income tax balances to reflect the changes in marginal rates, which results in either an increase or a decrease to their net deferred income tax liability balances. DPL records corresponding regulatory liabilities or assets to the extent such amounts are probable of settlement or recovery through customer rates and an adjustment to income tax expense for all other amounts. There were no adjustments to DPL's deferred income tax liability balances for the years ended December 31, 2024 and 2023.

Allocation of Tax Benefits

DPL is party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net federal and state benefits attributable to Exelon is reallocated to DPL and the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. DPL's federal tax benefit allocation from Exelon under the Tax Sharing Agreement was $5 million as of December 31, 2024. During 2023, DPL did not record an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement as a result of tax net operating loss.

Allocation of Income Taxes to Regulated Utilities

In Q2 2024, the IRS issued a series of private letter rulings (PLRs), to another taxpayer, providing guidance with respect to the application of the tax normalization rules to the allocation of consolidated tax benefits among the members of a consolidated group associated with NOLC for ratemaking purposes. The rulings provide that for ratemaking purposes the tax benefit of NOLC should be reflected on a separate company basis not taking into consideration the utilization of losses by other affiliates. A PLR issued to another taxpayer may not be relied on as precedent.

For DPL, the methodology prescribed by the IRS in these PLRs could result in a material reduction of the regulatory liability established for EDITs arising from the TCJA corporate tax rate change that are being amortized and flowed through to customers as well as a reduction in the accumulated deferred income taxes included in rate base for ratemaking purposes. DPL will record the impact, if any, upon receiving their own PLRs from the IRS.

8. Retirement Benefits

Defined Benefit Pension and Other Postretirement Employee Benefits

The table below shows the pension and OPEB plans in which Pepco employees participated as of December 31, 2024:

Name of Plan[(a)]:

Qualified Pension Plans:
- Exelon Corporation Retirement Program
- Exelon Pension Plan
- Pepco Holdings LLC Retirement Plan

Non-Qualified Pension Plans:
- Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan
- Conectiv Supplemental Executive Retirement Plan

OPEB Plans:
- PECO Energy Company Retiree Medical Plan
- Exelon Corporation Health Care Program
- BGE Retiree Medical Plan
- Pepco Holdings LLC Welfare Plan for Retirees

(a) Employees generally remain in their legacy benefit plans when transferring between operating companies.

Cost Allocation to DPL

DPL accounts for its participation in Exelon's pension and OPEB plans by applying multi-employer accounting. Components of pension and OPEB costs and contributions have been, and will continue to be, allocated to DPL based on both active and retired employee participation in each plan.

The amounts below represent DPL's allocated portion of the pension and OPEB plan costs, which were included in Operating Expenses within DPL's Statements of Income and Plant Utility within DPL's Balance Sheet for the years ended December 31, 2024 and 2023.

	2024	2023
Pension and OPEB	$ 15	$ 18

Contributions

The following table provide DPL's contributions to the pension and OPEB plans for the years ended December 31, 2024 and 2023:

	2024	2023
Pension	$ 1	$ 2
OPEB	2	2

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under the Employee Retirement Income Security Act (ERISA), contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the "Act"), management of the pension obligation, and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions reflect a funding strategy to make annual contributions with the objective of achieving 100% funded status on an accumulated benefit obligation basis over time. Unlike the qualified pension plans, non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While OPEB plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its OPEB plans, including liabilities management, levels of benefit claims paid, and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery).

The following table provides DPLs planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to OPEB plans in 2025.

Qualified Pension Plans	Non-Qualified Pension Plans	OPEB

2025	$	1 $	— $	1

Defined Contribution Savings Plan

DPL participates in a 401(k) defined contribution savings plans that are sponsored by Exelon. The plan is qualified under applicable sections of the Internal Revenue Code and allows employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. DPL matches a percentage of the employee contributions up to certain limits. The following table presents the employer contributions and employer matching contributions to the savings plans during the years ended December 31, 2024 and 2023.

	2024	2023
Savings Plan Matching Contributions	$ 5	$ 3

9. Derivative Financial Instruments

DPL uses derivative instruments to manage commodity price risk related to ongoing business operations. DPL does not execute derivatives for speculative or proprietary trading purposes.

Authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include Normal Purchase Normal Sale scope exception (NPNS), cash flow hedges, and fair value hedges. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivatives settle and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed.

Cash collateral held by DPL must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

Commodity Price Risk

DPL employs established policies and procedures to manage its risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, which are either determined to be non-derivative or classified as economic hedges. DPL procures electric and natural gas supply through a competitive procurement process approved by MDPSC and DEPSC. DPL's hedging programs are intended to reduce exposure to energy and natural gas price volatility and have no direct earnings impact as the costs are fully recovered from customers through regulatory-approved recovery mechanisms. The following table provides a summary of DPL's primary derivative hedging instruments, listed by commodity and accounting treatment.

Commodity	Accounting Treatment	Hedging Instrument
Electricity	NPNS	Fixed price contracts for all Standard Offer Service (SOS) requirements through full requirements contracts.
Gas	NPNS	Fixed and index priced contracts through full requirements contracts.
Gas	Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability[(a)]	Exchange traded future contracts for up to 50% of estimated monthly purchase requirements each month, including purchases for storage injections.

(a) The fair value of the DPL economic hedge is not material as of December 31, 2024 and 2023.

Credit Risk

DPL would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date.

DPL has contracts to procure electric and natural gas supply that provide suppliers with a certain amount of unsecured credit. If the exposure on the supply contract exceeds the amount of unsecured credit, the suppliers may be required to post collateral. The net credit exposure is mitigated primarily by the ability to recover procurement costs through customer rates. As of December 31, 2024 and 2023, the amount of cash collateral held with external counterparties by DPL was $2 million and less than one million, respectively, which is recorded in Miscellaneous Current and Accrued Liabilities (Account 242) in DPL's Balance Sheet.

DPL's electric supply procurement contracts do not contain provisions that would require them to post collateral. DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral in the form of cash or credit support, which vary by contract and counterparty, with thresholds contingent upon DPL's credit rating. As of December 31, 2024, DPL was not required to post collateral for any of these agreements. If DPL lost its investment grade credit rating as of December 31, 2024, it could have been required to post collateral to its counterparties of $10 million.

10. Debt and Credit Agreements

Short-Term Borrowings

DPL meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from PHI intercompany money pool. DPL may use its credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects DPL's commercial paper programs supported by the revolving credit agreements as of December 31, 2024 and 2023:

Credit Facility Size as of December 31,		Outstanding Commercial Paper as of December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
2024[(a)(b)]	2023[(a)(b)]	2024	2023	2024	2023
$ 300	$ 300	$ 144	$ 63	4.74 %	5.60 %

(a) As of December 31, 2024 and December 31, 2023, excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of $15 million, respectively. These facilities were entered into on October 4, 2024 and expire on October 3, 2025. These facilities may be utilized to issue letters of credit. As of December 31, 2024 and December 31, 2023 there were no outstanding letters of credit.
(b) The standard maximum program size for revolving credit facilities is $300 million for DPL based on the credit agreements in place. However, the facilities at Potomac Electric Power Company (Pepco), DPL, and Atlantic City Electric Company (ACE) have the ability to flex to $500 million, $500 million, and $350 million, respectively. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL, or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility. In January 2025, Pepco's program size was increased to $340 million, while DPL's was decreased to $260 million. In March 2025, Pepco's program size was reduced to $300 million, and DPL's was increased to $300 million. Throughout the period, the aggregate credit facility size for Pepco, DPL, and ACE did not exceed $900 million.

In order to maintain its commercial paper programs in the amount indicated above, DPL must have credit facilities in place, at least equal to the amount of its commercial paper program. DPL does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility.

At December 31, 2024, DPL had the following aggregate bank commitments, credit facility borrowings and available capacity under its credit facilities:

				Available Capacity as of December 31, 2024	
Facility Type	Aggregate Bank Commitment[(b)]	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper
Syndicated Revolver[(a)]	$ 300	$ —	$ —	$ 300	$ 156

(a) On August 29, 2024, DPL's syndicated revolving credit facilities were replaced with a new revolving credit facility with an aggregate bank commitment of $300 million at a variable interest rate of SOFR plus 1.000%, extending the maturity date to August 29, 2029.
(b) Excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of $15 million. These facilities expire on October 3, 2025. These facilities may be utilized to issue letters of credit.

Revolving Credit Agreements

Borrowings under DPL's revolving credit agreements bear interest at a rate based upon either the prime rate or a SOFR-based rate, plus an adder based upon it's credit rating. The adders for the prime based and SOFR-based borrowings are 0 basis points and 100 basis points, respectively, as of December 31, 2024. If DPL loses its investment grade rating, the maximum adders for prime rate borrowings and SOFR-based rate borrowings would be 65 and 165 basis points, respectively. The credit agreements also require DPL to pay a facility fee based upon the aggregate commitments. The fee varies depending upon DPL's credit rating. DPL had no outstanding amounts on the revolving credit facilities as of December 31, 2024.

Variable Rate Demand Bonds

DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders. These bonds may be converted to a fixed-rate, fixed-term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, DPL views VRDBs as a source of long-term financing. As of December 31, 2024 and 2023, $46 million and $79 million in VRDBs issued by DPL were outstanding and are included in Long-term debt on its Balance Sheet.

Long-Term Debt

The following table presents DPL's outstanding long-term debt as of December 31, 2024 and 2023:

			December 31,	
	Rates	Maturity Date	2024	2023
Long-term debt				
First mortgage bonds (Account 221)[(a)]	1.05% - 5.72%	2025 - 2054	$ 2,198	$ 2,024
Unsecured tax-exempt bonds (Account 221)	4.15% - 4.20%	2024	—	33
Medium-terms notes (unsecured) (Account 224)	7.72%	2027	10	10
Finance leases (Accounts 227 and 243)	5.62%	2025-2032	28	29
Total long-term debt			2,236	2,096
Unamortized debt discount and premium (Accounts 225 and 226)			—	—
Long-term debt			$ 2,236	$ 2,096

(a) Substantially all of DPL's assets are subject to the lien of its mortgage indenture.

Long-term debt maturities at DPL in the periods 2025 through 2029 and thereafter are as follows:

Year	DPL
2025	$ 130
2026	7
2027	16
2028	4
2029	3
Thereafter	2,076
Total	$ 2,236

Debt Covenants

As of December 31, 2024, DPL is in compliance with debt covenants.

11. Fair Value of Financial Assets and Liabilities

DPL measures and classifies fair value measurements in accordance with the hierarchy as defined by GAAP. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that DPL has the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following table presents the carrying amounts and fair values of DPL's short-term liabilities and long-term debt as of December 31, 2024 and 2023. DPL has no financial liabilities measured using the Net Asset Value ("NAV") practical expedient.

	December 31, 2024					December 31, 2023				
		Fair Value					Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year (Accounts 221, 224-227, 243)[(a)]	$ 2,236	$ —	$ 623	$ 1,250	$ 1,873	$ 2,096	$ —	$ 694	$ 1,134	$ 1,828

(a) The carrying amounts of DPL's short-term liabilities as presented on DPL's Balance Sheet are representative of their fair value (Level 2) because of the short-term nature of these instruments.

DPL uses the following methods and assumptions to estimate fair value of financial liabilities recorded at carrying cost:

Long-term debt, including amounts due within one year Type	Level	Valuation
Taxable Debt Securities	2	The fair value is determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. DPL obtains credit spreads based on trades of existing DPL debt securities as well as other issuers in the utility sector with similar credit ratings. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.
Variable Rate Financing Debt	2	Debt rates are reset on a regular basis and the carrying value approximates fair value.
Taxable Private Placement Debt Securities	3	Rates are obtained similar to the process for taxable debt securities. Due to low trading volume and qualitative factors such as market conditions, low volume of investors, and investor demand, these debt securities are Level 3.

Recurring Fair Value Measurements

The following table presents assets and liabilities measured and recorded at fair value on DPL's Balance Sheet on a recurring basis and their level within the fair value hierarchy as of December 31, 2024 and 2023. DPL has no financial assets or liabilities measured using the NAV practical expedient:

As of December 31, 2024	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents (Accounts 132-134, 136)[(a)]	$ 3	$ —	$ —	$ 3
Total assets	3	—	—	3
Total net assets	$ 3	$ —	$ —	$ 3

As of December 31, 2023	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents (Accounts 132-134, 136)[(a)]	$ 1	$ —	$ —	$ 1
Total assets	1	—	—	1
Total net assets	$ 1	$ —	$ —	$ 1

(a) DPL excludes cash of $20 million and $15 million as of December 31, 2024 and 2023, respectively.

DPL had no Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2024 and 2023.

Valuation Techniques Used to Determine Fair Value

Cash Equivalents. Investments with original maturities of three months or less when purchased, including mutual and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

12. Commitments and Contingencies

Commitments

PHI Merger Commitments

Approval of the PHI merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments. The following amounts represent total commitment costs that have been recorded since the acquisition date and the total remaining obligations for DPL at December 31, 2024:

Description	December 31, 2024
Total commitments	$ 89
Remaining commitments[(a)]	1

(a) Remaining commitments extend through 2026 and include accounts receivable forgiveness programs, charitable contributions and rate credits.

Commercial Commitments

DPL's commercial commitments as of December 31, 2024, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2025	2026	2027	2028	2029	2030 and beyond
Letters if credit[(a)]	$ 1	1	—	—	—	—	—
Surety bonds[(b)]	6	6	—	—	—	—	—
Guaranteed lease residual values[(c)]	10	—	2	2	2	2	2
Total commercial commitments	$ 17	$ 7	$ 2	$ 2	$ 2	$ 2	$ 2

(a) DPL maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds. Historically, payments under the guarantees have not been made and the likelihood of payments being required is remote.
(c) Represents the maximum potential obligation in the event the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The lease term associated with these assets ranges from 1 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $23 million is guaranteed by DPL. Historically, payments under the guarantees have not been made and DPL believes the likelihood of payments being required under the guarantees is remote.

Leases

DPL's future minimum lease payments for operating leases as of December 31, 2024 were as follows:

2025	$ 8
2026	6
2027	6
2028	6
2029	6
Remaining years	16
Total minimum future lease payments	$ 48

Environmental Remediation Matters

General

DPL's operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under federal and state environmental laws, DPL is generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. DPL owns or leases a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, DPL is currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, DPL cannot reasonably estimate whether it will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by DPL, environmental agencies, or others, or whether such costs will be recoverable from third parties, including customers. Additional costs could have a material, unfavorable impact on the DPL's financial statements.

MGP Sites

DPL has identified sites where former manufactured gas plant (MGP) or gas purification activities have or may have resulted in actual site contamination. For some of these sites, there are additional potentially responsible parties that may share responsibility for the ultimate remediation of each location. DPL has identified 1 site currently under study and the required cost at the site is not expected to be material.

The historical nature of the MGP and gas purification sites, and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency. While DPL does not have riders for MGP clean-up costs, DPL has historically received recovery of actual clean-up costs in distribution rates.

As of both December 31, 2024 and 2023, DPL had accrued $1 million in undiscounted amounts for environmental investigation and remediation liabilities in Miscellaneous Current and Accrued Liabilities (Account 242) on its Balance Sheet. The amounts related to MGP investigation and remediation were immaterial.

Litigation and Regulatory Matters

Fund Transfer Restrictions. Under applicable law, DPL can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at DPL may limit the dividends that the company can distribute to Exelon.

DPL is subject to certain dividend restrictions established by settlements approved by the DEPSC and MDPSC that prohibit DPL from paying a dividend on its common shares if (a) after the dividend payment, DPL's equity ratio would be below 48% as calculated pursuant to the DEPSC's and MDPSC's ratemaking precedents, or (b) DPL's corporate issuer or senior unsecured credit rating, or its equivalent, is rated by any of the three major credit rating agencies below the generally accepted definition of investment grade. No such event has occurred.

Maryland Sales and Use Tax Refund Claim. Maryland imposes a 6% sales and use tax on the purchase of most goods and services. DPL has filed or plans to file protective refund claims, totaling an estimated $10 million, treating electric transmission and distribution machinery and equipment as nontaxable pursuant to the manufacturing exemption available under the Maryland sales and use tax law. The Maryland Comptroller has initially denied the refund claim and litigation is pending.

On November 22, 2024, the Appellate Court of Maryland, in a case involving a regulated electric utility operating in Maryland, ruled the purchase of certain transmission and distribution equipment qualify for the sales tax manufacturing exemption. On December 20, 2024, the Maryland Attorney General, on behalf of the Maryland Comptroller, filed a motion for reconsideration with the Appellate Court of Maryland of its ruling. The motion for reconsideration was denied on February 3, 2025.

On February 18, 2025, the Maryland Attorney General, on behalf of the Maryland Comptroller, filed a petition with the Maryland Supreme Court requesting review of the Appellate Court of Maryland's ruling.

In the event transmission and distribution equipment is determined to be exempt, DPL will record an estimated receivable of $10 million. The sales tax payments were primarily capitalized; therefore, the refund would be recorded as a reduction to property, plant, and equipment included in rate base.

General. DPL is involved in various other litigation matters that are being defended and handled in the ordinary course of business. DPL is also from time to time subject to audits and investigations by the FERC and other regulators. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. DPL maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

13. Shareholder's Equity

Common Stock (Account 201)

The following table presents common stock authorized and outstanding as of December 31, 2024 and 2023:

	Par Value	Shares Authorized	December 31, 2024 Shares Outstanding	December 31, 2023 Shares Outstanding
Common stock	$ 2.25	1,000	1,000	1,000

Preferred and Preference Securities (Account 204)

There were no shares of preferred or preference securities authorized as of December 31, 2024 and 2023.

14. Supplemental Financial Information

Supplemental Statement of Income Information

The following table provides additional information about material items recorded in DPL's Statement of Income for the years ended December 31, 2024 and 2023:

	For the Years Ended December 31, 2024	2023
Taxes other than income taxes (Accounts 408.1 and 408.2)		
Utility[(a)]	$ 27	$ 26
Property	48	44
Payroll	4	5

(a) DPL's utility taxes represent municipal and state utility taxes and gross receipts taxes related to its operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues in DPL's Statement of Income.

Supplemental Statement of Cash Flows Information

The following table provides additional information about DPL's Statement of Cash Flows for the years ended December 31, 2024 and 2023:

	For the Years Ended December 31, 2024	2023
Cash paid (refunded) during the year		
Interest (net of amount capitalized)	$ 89	$ 69
Income taxes (net of refunds)	57	6
Non-cash investing activities		
Increase (decrease) in capital expenditures not paid	$ 41	$ (6)

15. Related Party Transactions

Service Company Costs for Corporate Support

DPL receives a variety of corporate support services from Exelon Business Services Company, LLC (BSC) and PHI Service Company (PHISCO). The following table presents the service company costs allocated to DPL:

	Operating and maintenance from affiliates For the Years Ended December 31, 2024	2023	Capitalized costs For the Years Ended December 31, 2024	2023
BSC	$ 78	$ 73	$ 49	$ 43
PHISCO	103	98	34	29

Current Receivables from Affiliates

The following table presents DPL's current Receivables from affiliates:

	At December 31, 2024	2023
ACE	$ —	$ 1
Total (Account 146)	$ —	$ 1

Current Payables to Affiliates

The following table presents DPL's current Payables to affiliates:

	At December 31, 2024	2023
PECO	$ —	$ 1
BSC	14	12
PHISCO	11	11
Other	1	1
Total (Account 234)	$ 26	$ 25

Borrowings from PHI intercompany money pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, PHI operates an intercompany money pool that DPL participates in.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year									
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income									
3	Preceding Quarter/Year to Date Changes in Fair Value									

4	Total (lines 2 and 3)								176,752,364	176,752,364
5	Balance of Account 219 at End of Preceding Quarter/Year									
6	Balance of Account 219 at Beginning of Current Year									
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income									
8	Current Quarter/Year to Date Changes in Fair Value									
9	Total (lines 7 and 8)								208,821,971	208,821,971
10	Balance of Account 219 at End of Current Quarter/Year									

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	6,594,339,082	5,499,430,091	884,612,409				210,296,582
4	Property Under Capital Leases	50,615,407	50,615,407					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	672,904,672	550,020,956	91,815,335				31,068,381
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	7,317,859,161	6,100,066,454	976,427,744				241,364,963
9	Leased to Others							
10	Held for Future Use	20,786,706	20,786,706					
11	Construction Work in Progress	276,136,833	195,136,040	61,012,499				19,988,294
12	Acquisition Adjustments	50,046,281	50,046,281					
13	Total Utility Plant (8 thru 12)	7,664,828,981	6,366,035,481	1,037,440,243				261,353,257
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	2,086,960,360	1,683,306,424	259,917,494				143,736,442
15	Net Utility Plant (13 less 14)	5,577,868,621	4,682,729,057	777,522,749				117,616,815
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,895,477,145	1,553,688,048	258,163,339				83,625,758
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	141,436,934	79,572,095	1,754,155				60,110,684
22	Total in Service (18 thru 21)	2,036,914,079	1,633,260,143	259,917,494				143,736,442
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							

27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	50,046,281	50,046,281					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,086,960,360	1,683,306,424	259,917,494				143,736,442

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction					
5	(Other Overhead Construction Costs, provide details in footnote)					
6	SUBTOTAL (Total 2 thru 5)					
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL (Total 8 & 9)					
11	Spent Nuclear Fuel (120.4)					
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)					
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)					
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	2,341					2,341
4	(303) Miscellaneous Intangible Plant	78,244,326	12,493,322				90,737,648
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	78,246,667	12,493,322				90,739,989
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights						
9	(311) Structures and Improvements						
10	(312) Boiler Plant Equipment						
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units						
13	(315) Accessory Electric Equipment						
14	(316) Misc. Power Plant Equipment						
15	(317) Asset Retirement Costs for Steam Production						
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)						
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights						
19	(321) Structures and Improvements						
20	(322) Reactor Plant Equipment						
21	(323) Turbogenerator Units						
22	(324) Accessory Electric Equipment						
23	(325) Misc. Power Plant Equipment						
24	(326) Asset Retirement Costs for Nuclear Production						
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)						
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights						
28	(331) Structures and Improvements						
29	(332) Reservoirs, Dams, and Waterways						
30	(333) Water Wheels, Turbines, and Generators						
31	(334) Accessory Electric Equipment						
32	(335) Misc. Power Plant Equipment						
33	(336) Roads, Railroads, and Bridges						
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)						
36	D. Other Production Plant						
37	(340) Land and Land Rights						
38	(341) Structures and Improvements						

39	(342) Fuel Holders, Products, and Accessories						
40	(343) Prime Movers						
41	(344) Generators						
42	(345) Accessory Electric Equipment						
43	(346) Misc. Power Plant Equipment						
44	(347) Asset Retirement Costs for Other Production						
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)						
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)						
47	3. Transmission Plant						
48	(350) Land and Land Rights	54,084,159					54,084,159
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	91,587,125	28,475,208	134,984		(3,510,930)	116,416,419
50	(353) Station Equipment	712,917,977	67,740,047	2,524,446			778,133,578
51	(354) Towers and Fixtures	73,959,046	1,385,303	25,922			75,318,427
52	(355) Poles and Fixtures	649,244,971	99,532,946	2,004,585			746,773,332
53	(356) Overhead Conductors and Devices	374,505,238	16,490,326	998,859			389,996,705
54	(357) Underground Conduit	6,505,800	472				6,506,272
55	(358) Underground Conductors and Devices	63,076,626	40,526				63,117,152
56	(359) Roads and Trails	1,110,956					1,110,956
57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,026,991,898	213,664,828	5,688,796		(3,510,930)	2,231,457,000
59	4. Distribution Plant						
60	(360) Land and Land Rights	15,385,479				4,770,966	20,156,445
61	(361) Structures and Improvements	60,783,042	3,086,326	53,276			63,816,092
62	(362) Station Equipment	517,086,980	62,312,863	1,160,021			578,239,822
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	289,354,667	11,432,917	668,600			300,118,984
65	(365) Overhead Conductors and Devices	513,617,671	47,269,016	3,581,701			557,304,986
66	(366) Underground Conduit	26,186,094	161,361				26,347,455
67	(367) Underground Conductors and Devices	486,160,381	25,936,561	1,161,539			510,935,403
68	(368) Line Transformers	679,625,140	62,498,827	3,529,095			738,594,872
69	(369) Services	238,263,278	21,516,655	755,837			259,024,096
70	(370) Meters	139,537,988	4,328,810	1,205,867		(21,473)	142,639,458
71	(371) Installations on Customer Premises	44,299,017	474,680	2,217			44,771,480
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	91,420,118	9,646,691	946,691			100,120,118
74	(374) Asset Retirement Costs for Distribution Plant	4,607,315	(216,185)	(7,888)			4,399,018
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,106,327,170	248,448,522	13,056,956		4,749,493	3,346,468,229
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market						

	Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	2,998,246					2,998,246
87	(390) Structures and Improvements	58,203,455	6,976,108	256,799			64,922,764
88	(391) Office Furniture and Equipment	18,036,497	4,835,958	427,354			22,445,101
89	(392) Transportation Equipment	49,216,250	9,132,920	40,921			58,308,249
90	(393) Stores Equipment	152,591		(81,480)			234,071
91	(394) Tools, Shop and Garage Equipment	25,320,898	6,956,353	2,658,919			29,618,332
92	(395) Laboratory Equipment						
93	(396) Power Operated Equipment						
94	(397) Communication Equipment	226,150,102	21,437,358	610,968			246,976,492
95	(398) Miscellaneous Equipment	5,195,112	66,220	118,024			5,143,308
96	SUBTOTAL (Enter Total of lines 86 thru 95)	385,273,151	49,404,917	4,031,505			430,646,563
97	(399) Other Tangible Property	4,735					4,735
98	(399.1) Asset Retirement Costs for General Plant	749,938					749,938
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	386,027,824	49,404,917	4,031,505			431,401,236
100	TOTAL (Accounts 101 and 106)	5,597,593,559	524,011,589	22,777,257		1,238,563	6,100,066,454
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	5,597,593,559	524,011,589	22,777,257		1,238,563	6,100,066,454

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
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47	TOTAL					

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Ocean City-West Culver : SS322B	11/01/2019	12/01/2026	1,104,133
3	Lakeside Substation Land; 8 Acres, Talbot County MD	12/01/2010	06/01/2030	406,468
4	Magnolia Substation Land: 11+Acres	08/01/2010	06/01/2030	1,180,361

5	Ocean City-St Louis & 2nd : SSTA749	12/01/2020	12/31/2026	760,286
6	Graceton Jenkins Sub	02/15/2021	12/31/2034	1,372,880
7	Maridel Substation	12/31/2022	12/31/2028	5,435,571
8	Assawoman Substation	12/01/2023	03/01/2025	2,520,000
9	Middletown Substation	03/01/2023	12/31/2027	6,045,639
10	Foulk Road Substation : SS157N	12/01/2024	12/01/2029	1,697,187
11	Total of Land under $250,000	12/01/2019	12/31/2026	264,181
21	Other Property:			
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47	TOTAL			20,786,706

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Brandywine Software Switchgear Replacement	11,536,194
2	Red Lion AT50 Transformers & Spare	9,985,241
3	EU GIS CORE Software	9,022,726

4	OCMD BatteryStorage Substation	7,008,582
5	CrisfieldKings Creek Construction	6,927,545
6	Tower Replacement DE	6,082,423
7	Substation FO Entrance DE	4,492,272
8	Red Lion T1 for 68457	4,350,575
9	SCB PHI Case #9461 Software	4,016,903
10	Distribution Automation DE	3,992,776
11	ADMS - Cap Software #2 Software	3,620,828
12	S. Harrington Trans Spare Transformer	3,417,550
13	Milford Spare Transformer	3,417,550
14	Router Upgr Cores Edges DE	3,018,688
15	Reybold T2	2,547,589
16	Crisfield Sub New 69KV Terminal	2,521,164
17	Milford Sub - FEP	2,286,491
18	Ocean City Rebuild Structure	2,202,321
19	West T4 Transformer Install	2,184,664
20	13764 Rebuild MD Portion	2,144,412
21	Steele Spare Transformer	2,110,324
22	Crisfield T1 Replace Transformer ECA	1,938,460
23	W. Cambridge T2 Transformer	1,892,856
24	Piney Grove AT20 Replace	1,828,874
25	Unbilled Cap DPL MD Non-Standard	1,826,311
26	IDS Design Build Install DE	1,805,948
27	North Seaford AT1 Auto-Transformer	1,786,741
28	DPL Steele - FEP	1,670,858
29	Carrcroft AT1 Transformer Replacement	1,640,372
30	Silverside T2 Transformer Replacement	1,513,266
31	Narrow Distribution Exit	1,393,445
32	DER and Load Forecasting Software	1,346,764
33	Brandywine Sub Transformer	1,343,008
34	Maridel T1 Replace Transformer ECA	1,315,516
35	Hockesson Dist Spare Transformer	1,314,665
36	ECA Dist St Svc Transformers	1,241,084
37	Loretto Spare Transformer	1,226,817
38	Distribution Automation DPL MD	1,213,026
39	S. Harrington Dist Spare Transformer	1,209,356
40	Ocean Bay Dist upgrade BESS	1,167,501
41	EMS Upgrade - Software	1,125,059
42	Glasgow Fence & Ground Grid	1,093,015
43	Centreville Spare Transformer	1,088,620
44	EU GIS DQ Software	1,069,857
45	ITN 87545	1,054,683
46	Faulk Rd T2 Transformer	1,041,339
47	Ocean Bay Upgrade for BESS	1,035,674
48	Indian River 230 - FEP	1,034,443
49	Miscellaneous projects under $1,000,000	61,031,664
43	Total	195,136,040

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	1,444,156,685	1,444,156,685		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	168,314,469	168,314,469		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,519,657	3,519,657		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	[(a)] 292,253	292,253		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	172,126,379	172,126,379		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(22,777,257)	(22,777,257)		
13	Cost of Removal	(44,649,985)	(44,649,985)		
14	Salvage (Credit)	4,257,552	4,257,552		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(63,169,690)	(63,169,690)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):				
17.2	Third Party Reimbursements	574,674	574,674		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,553,688,048	1,553,688,048		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	569,486,572	569,486,572		
26	Distribution	870,102,230	870,102,230		
27	Regional Transmission and Market Operation				
28	General	114,099,246	114,099,246		
29	TOTAL (Enter Total of lines 20 thru 28)	1,553,688,048	1,553,688,048		

FOOTNOTE DATA

(a) Concept: OtherAccounts

Depreciation related to the company's asset retirement obligations (ARO) are reclassified to other Regulatory Assets (182.3) as follows:		
ARO	$	292,253
Total	$	292,253

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
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42	Total Cost of Account 123.1 $		Total						

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	[(a)]66,078,954	[(b)]84,368,041	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)	902,315	1,548,859	Electric
9	Distribution Plant (Estimated)	4,841,258	9,067,034	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	71,822,527	94,983,934	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies	71,822,527	94,983,934	

	(2) A Resubmission		

FOOTNOTE DATA

[(a)](#) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Assigned to - Construction (Estimated)		
Transmission Plant - Electric (Estimated)	$	10,381,004
Distribution Plant - Electric & Gas (Estimated)		55,697,950
Assigned to - Construction (Estimated)	$	66,078,954

[(b)](#) Concept: PlantMaterialsAndOperatingSuppliesConstruction

Assigned to - Construction (Estimated)		
Transmission Plant - Electric (Estimated)	$	12,309,297
Distribution Plant - Electric & Gas (Estimated)		72,058,744
Assigned to - Construction (Estimated)	$	84,368,041

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

		Current Year		Year One		Year Two		Year Three		Future Years		Totals	
Line No.	SO2 Allowances Inventory (Account 158.1) (a)	No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	254,521	8,204,386									254,521	8,204,386
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9	DE RPS RECs Purchased	617,261	18,642,578									617,261	18,642,578
10	MD HPS RECs Purchased	288	13,376									288	13,376
11	MD RECs Received	149,037	5,543,023									149,037	5,543,023
12	DE RECs Received												
13													
14													
15	Total	[(a)](#)766,586	[(c)](#)24,198,977									766,586	24,198,977
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
21	Cost of Sales/Transfers:												
22	Total												
23	Cost of Sales/Transfers:												

24	DE RECs Retired	583,790	18,008,440									583,790	18,008,440
25	MD RECs Retired	149,325	5,556,406									149,325	5,556,406
26													
27													
28	Total	(b) 733,115	(d) 23,564,846									733,115	23,564,846
29	Balance-End of Year	287,992	8,838,517									287,992	8,838,517
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AllowancesInventoryPurchasesTransfersNumber

Represents renewable energy credits acquired and received to meet the Renewable Energy Portfolio Standards (RPS) for the state of DE and MD.

(b) Concept: AllowancesInventorySalesTransfersNumber

Represents renewable energy credits retired to meet the Renewable Energy Portfolio Standards (RPS) for the states of DE and MD.

(c) Concept: AllowancesInventoryPurchasesTransfers

Represents the dollar value of renewable energy credits acquired and received to meet the Renewable Energy Portfolio Standards (RPS) for the state of DE and MD.

(d) Concept: AllowancesInventorySalesTransfers

Represents the dollar value of renewable energy credits retired to meet the Renewable Energy Portfolio Standards (RPS) for the states of DE and MD.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.

9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

		Current Year		Year One		Year Two		Year Three		Future Years		Totals	
Line No.	NOx Allowances Inventory (Account 158.1) (a)	No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year												
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)												
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year												
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												

41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

	This report is:		

Name of Respondent:
Delmarva Power & Light Company

(1) An Original
(2) A Resubmission

Date of Report:
12/31/2024

Year/Period of Report
End of: 2024/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent:
Delmarva Power & Light Company

This report is:
(1) An Original
(2) A Resubmission

Date of Report:
12/31/2024

Year/Period of Report
End of: 2024/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line	Description	Costs Incurred During Period	Account Charged	Reimbursements Received During the Period	Account Credited With

No.	(a)	(b)	(c)	(d)	Reimbursement (e)
1	**Transmission Studies**				
2	N/A				
20	Total				
21	**Generation Studies**				
22	N/A				
39	Total				
40	Grand Total				

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Other Vacation Accrual	3,490,428	207,956	—		3,698,384
2	Asset Retirement Obligation	3,031,168	883,316	108	18,333	3,896,151
3	[a] Transmission Service Revenue	21,765,422	12,104,966	[c] Various	22,038,251	11,832,137
4	DE Renewable Portfolio Surcharge Deferral	702,644	163,938	—		866,582
5	[b] DE Electric Costs to Achieve (CTA) Deferral	74,226		407.3	42,093	32,133
6	DE SFAS 133 Gas Derivatives	3,365,418		242	3,365,418	
7	DE Third Party Supplier Recovery	2,015,179	732,000	232	2,034,167	713,012
8	MD Costs to Achieve (CTA) Deferral	154,725		407.3	100,449	54,276
9	MD Rate Case Costs	441,628		[d] Various	238,675	202,953
10	DE DSM - Energy Efficiency		1,263,986	[e] Various	339,096	924,890
11	AMI / Smart Grid - DE	17,239,045	103,765	[f] Various	4,010,595	13,332,215
12	Recoverable DE DLC Costs	7,243,168		407.3	2,102,473	5,140,695
13	DE Gas IMU	3,932,411	21,209	[g] Various	706,773	3,246,847
14	DE Gas Costs to Achieve (CTA) Deferral	85,348		407.3	49,555	35,793
15	DSM - Energy Efficiency Products MD	62,626,902	18,550,438	407.3	14,136,966	67,040,374
16	DSM - Direct Load Control Program MD	5,269,759	944,318	407.3	929,660	5,284,417
17	AMI / Smart Grid - MD	5,242,214	72,790	407.3	1,773,172	3,541,832
18	MD AMI Loss on Retirement of Meters	4,720,153		407.3	1,483,846	3,236,307
19	Delaware SOS: Energy	505,945	7,847,850	—		8,353,795
20	Delaware SOS: Interest	467,972	69,342	—		537,314
21	Maryland SOS: Energy		9,096,831	—		9,096,831
22	Maryland SOS: Transmission	2,213,802	2,064,869	—		4,278,671
23	Maryland SOS: Administrative Costs	775,188	720,417	—		1,495,605
24	MD Incremental Storm Costs	1,463,083		[h] Various	584,086	878,997

25	Tax Cuts and Jobs Act	4,402,606	281,344	(c) Various	3,719,018	964,932
26	MD Electric Vehicle	1,202,268	264,035	407.3	307,006	1,159,297
27	DE Incremental COVID-19 Cost	5,441,568	126,455	(d) Various	2,633,375	2,934,648
28	MD Incremental COVID-19 Cost	496,992	42,051	407.3	142,508	396,535
29	MD Battery Storage	2,183,367		407.3	242,596	1,940,771
30	MD Incremental IIJA Costs	89,380	10,186	—		99,566
31	Accrued Anniversary Credits	625,900	148,700	—		774,600
44	TOTAL	161,267,909	55,720,762		60,998,111	155,990,560

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:

Line No.	Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
3	Transmission Service Revenue	FERC Docket No. ER05-515
4	DE Renewable Portfolio Surcharge Deferral	DEPSC Regulation Docket No. 56
5	DE Electric Costs to Achieve (CTA) Deferral	DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977, DEPSC Docket No. 20-0149
6	DE SFAS 133 Gas Derivatives	DEPSC Docket No. 97-293F
7	DE Third Party Supplier Recovery	DEPSC Docket No. 15-1693
8	MD Costs to Achieve (CTA) Deferral	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630
9	MD Rate Case Costs	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630, MDPSC Case No. 9670, MDPSC Case No. 9681
10	DE DSM - Energy Efficiency	DEPSC Docket No. 17-0985
11	AMI / Smart Grid - DE	DEPSC Docket No. 11-528, DEPSC Docket No. 13-115, DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977
12	Recoverable DE DLC Costs	DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977
13	DE Gas IMU	DEPSC Docket No. 09-277T, DEPSC Docket No. 10-237, DEPSC Docket No. 11-528, DEPSC Docket No. 12-546, DEPSC Docket No. 17-0978
14	DE Gas Costs to Achieve (CTA) Deferral	DEPSC Docket No. 17-0978, DEPSC Docket No. 20-0150
15	DSM - Energy Efficiency Products MD	MDPSC Case No. 9156
16	DSM - Direct Load Control Program MD	MDPSC Case No. 9156
17	AMI / Smart Grid - MD	MDPSC Case No. 9424, MDPSC Case No. 9455
18	MD AMI Loss on Retirement of Meters	MDPSC Case No. 9424
19	Delaware SOS: Energy	DEPSC Docket No. 04-391
20	Delaware SOS: Interest	DEPSC Docket No. 04-391
21	Maryland SOS: Energy	MDPSC Case No. 8908
22	Maryland SOS: Transmission	MDPSC Case No. 8908
23	Maryland SOS: Administrative Costs	MDPSC Case No. 8908
24	MD Incremental Storm Costs	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630, MDPSC Case No. 9670
25	Tax Cuts and Jobs Act	MDPSC Case No. 9630, DEPSC Docket No. 20-0149, Docket No. 22-0897
26	MD Electric Vehicle	MDPSC Case No. 9478, MDPSC Case No. 9681
27	DE Incremental COVID-19 Cost	DEPSC Docket No. 20-0286, Docket No. 22-0897
28	MD Incremental COVID-19 Cost	MDPSC Case No. 9670, MDPSC Case No. 9681
29	MD Battery Storage	MDPSC Case No. 9619, MDPSC Case No. 9681
30	MD Incremental IIJA Costs	MDPSC Final Order No. 90272

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

DPL amortizes the regulatory assets in account 182.3 based on the following amortization periods:

Line No.	Description of Other Regulatory Assets	Amortization Lives
5	DE Electric Costs to Achieve (CTA) Deferral	5 years
8	MD Costs to Achieve (CTA) Deferral	5 years
9	MD Rate Case Costs	3 years
11	AMI / Smart Grid - DE	15 years
12	Recoverable DE DLC Costs	10 years
13	DE Gas IMU	15 years
14	DE Gas Costs to Achieve (CTA) Deferral	5 years
15	DSM - Energy Efficiency Products MD	5 years
16	DSM - Direct Load Control Program MD	15 years
17	AMI / Smart Grid - MD	10 years
18	MD AMI Loss on Retirement of Meters	10 years
24	MD Incremental Storm Costs	5 years
25	Tax Cuts and Jobs Act	32 years
26	MD Electric Vehicle	5 years
28	MD Incremental COVID-19 Cost	5 years
29	MD Battery Storage	10 years

(c) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

The following are the individual components of "Various":

$	8,449,333	Recorded to account 407.4
	13,588,918	Recorded to account 456.1
$	22,038,251	Total

(d) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

The following are the individual components of "Various":

$	195,667	recorded to account 407.3
	43,008	recorded to account 928
$	238,675	Total

(e) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

The following are the individual components of "Various":

$	232,105	recorded to account 254 - Reclass included in DE DSM - Energy Efficiency line 16, page 278
	106,991	recorded to account 908
$	339,096	Total

(f) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

The following are the individual components of "Various":

$	3,940,784	recorded to account 407.3
	69,811	recorded to account 923
$	4,010,595	Total

(g) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

The following are the individual components of "Various":

$	636,271	recorded to account 407.3
	70,502	recorded to account 923
$	706,773	Total

(h) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

The following are the individual components of "Various":

$	578,754	recorded to account 593
	5,332	recorded to account 903
$	584,086	Total

(i) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

The following are the individual components of "Various":

$	471,797	recorded to account 407.3
	3,247,221	recorded to account 254 - Reclass included in Tax Cuts and Jobs Act line 11, pg. 278
$	3,719,018	Total

(j) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged

The following are the individual components of "Various":

$	708,221	recorded to account 407.3
	1,925,154	recorded to account 254 - Reclass included in DE Incremental COVID-19 Cost line 18, pg. 278
$	2,633,375	Total

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MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Prepaid Pension Costs	135,210,445	658,224	(b) various	15,990,457	119,878,212
2	LT Customer Payment Receivables	53,556		143	732	52,824
3	LT Receivable from PJM	433,976		143	433,976	
4	Other A/R Worker Compensation	1,149,028	110,216	(c) various	272,398	986,846
5	(a) Maintenance and Inspection plan contract	428,633	106,625	(d) various	53,526	481,732
6	Deposits for Equipment	1,066,933		232	1,066,933	
7	Other	9,925	636,659	242	621,241	25,343
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	138,352,496				121,424,957

FOOTNOTE DATA

[(a)] Concept: DescriptionOfMiscellaneousDeferredDebits
Maintenance and Inspection plan contract will be amortized over 10 years.
[(b)] Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged
Prepaid Pension Cost is offset in Accounts 228.3, 926, 107, and 108.
[(c)] Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged
Other A/R Worker's Compensation is offset in Accounts 228.2, 925, 107, 108, 143, and 174.
[(d)] Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged
Maintenance and Inspection plan contract is offset in Accounts 580 and 588.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric	116,753,668	103,265,682
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	[(a)]116,753,668	[(b)]103,265,682
9	Gas		
10	Gas	14,541,857	12,743,678
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	14,541,857	12,743,678
17.1	AMT Credit / Other		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	131,295,525	116,009,360

Notes

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

[(a)] Concept: AccumulatedDeferredIncomeTaxes

Account 190 Activity		
410.1 Debits	$	19,577,130
411.1 Credits		(9,996,302)
Net Debits/(Credits)	$	9,580,828
Account 190 Activity		
410.2 Debits	$	81,011
411.2 Credits		(1,618,805)
Net Debits/(Credits)	$	(1,537,794)
Account 190 Activity B/S Only		
410 Debits	$	—
411 Credits		(7,243,131)
Net Debits/(Credits)	$	(7,243,131)
Net Change	**$**	**(15,286,165)**

190	**Electric**	**Gas**	**Total**
Accrued Benefits	$ 1,221,741	$ 198,888	$ 1,420,629

Accrued Bodily Injuries	429,740	69,958	499,698
Accrued Bonuses & Incentives	2,399,246	390,575	2,789,821
Accrued Environmental Liability	133,057	21,660	154,717
Accrued Legal	—	—	—
Accrued OPEB	1,965,903	320,031	2,285,934
Accrued Other Expenses	733,938	119,478	853,416
Accrued Payroll Taxes - AIP	(579,240)	(94,295)	(673,535)
Accrued Severance	23,835	3,880	27,715
Accrued Vacation	239,486	38,986	278,472
Accrued Worker's Compensation	625,815	101,877	727,692
Allowance for Doubtful Accounts	6,236,000	1,015,163	7,251,163
Asset Retirement Obligation	2,970,894	483,634	3,454,528
Charitable Contribution Carryforward	114,745	18,679	133,424
Corporate Alternative Minimum Tax	1,435,870	159,541	1,595,411
Deferred Compensation	(285,327)	(46,449)	(331,776)
Deferred Revenue	3,151,545	513,042	3,664,587
Other Deferred Credits	50,934	8,292	59,226
Purchased Power	5,548,048	903,171	6,451,219
Regulatory Liability	4,145,609	659,815	4,805,424
Sales & Use Tax Reserve	171,513	27,921	199,434
State Income Taxes	1,139,028	185,423	1,324,451
State Net Operating Loss Carryforward - MD	6,859,578	762,175	7,621,753
Maryland Additional Subtraction Carryforward	7,171,350	796,817	7,968,167
Maryland 10-309 Carryforward	2,278,510	253,168	2,531,678
State Net Operating Loss Carryforward - DE	31,701,454	3,522,384	35,223,838
Delaware NOL - Valuation Allowance	(31,454,532)	(3,494,948)	(34,949,480)
Unamortized Investment Tax Credit	198,645	32,338	230,983
Other Deferred Tax Assets	20,647	3,360	24,007
Income Tax Regulatory Liability	68,105,636	7,567,293	75,672,929
Total	$ 116,753,668	$ 14,541,857	$ 131,295,525

(b) Concept: AccumulatedDeferredIncomeTaxes

190	Electric	Gas	Total
Accrued Benefits	$ 1,484,986	$ 241,742	$ 1,726,728
Accrued Bodily Injuries	446,418	72,673	519,091
Accrued Bonuses & Incentives	2,900,947	472,247	3,373,194
Accrued Environmental Liability	187,189	30,473	217,662
Accrued Legal	—	—	—
Accrued OPEB	1,225,161	199,445	1,424,606
Accrued Other Expenses	404,059	65,777	469,836
Accrued Payroll Taxes - AIP	212,972	34,670	247,642
Accrued Severance	23,835	3,880	27,715
Accrued Vacation	387,123	63,020	450,143
Accrued Worker's Compensation	606,671	98,760	705,431
Allowance for Doubtful Accounts	6,011,841	978,672	6,990,513
Asset Retirement Obligation	3,048,885	496,330	3,545,215
Charitable Contribution Carryforward	—	—	—
Corporate Alternative Minimum Tax	3,670,178	407,798	4,077,976
Deferred Compensation	21,423	3,487	24,910
Deferred Revenue	3,024,906	492,427	3,517,333
Other Deferred Credits	50,934	8,292	59,226
Purchased Power	—	—	—
Regulatory Liability	3,115,710	566,880	3,682,590
Sales & Use Tax Reserve	188,095	30,620	218,715
State Income Taxes	(119,117)	(19,391)	(138,508)
State Net Operating Loss Carryforward - MD	4,767,903	529,767	5,297,670
Maryland Additional Subtraction Carryforward	7,245,637	805,071	8,050,708
Maryland 10-309 Carryforward	2,333,921	259,325	2,593,246
State Net Operating Loss Carryforward - DE	29,362,368	3,262,485	32,624,853
Delaware NOL - Valuation Allowance	(29,115,446)	(3,235,050)	(32,350,496)
Unamortized Investment Tax Credit	153,108	24,925	178,033
Other Deferred Tax Assets	39,158	6,373	45,531
Income Tax Regulatory Liability	61,586,817	6,842,980	68,429,797
Total	$ 103,265,682	$ 12,743,678	$ 116,009,360

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2		[a]1,000	2.25		1,000	2,250				

6	Total	1,000			1,000	2,250				
7	Preferred Stock (Account 204)									
8										
9										
10										
11	Total									

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: CommonStockSharesAuthorized

Reference is made to the Delmarva Power & Light Company's Balance Sheet in the Exelon Corporation Form 10-K page 150, filed with the Securities and Exchange Commission for the year ended December 31, 2024.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2024-12-31	Year/Period of Report End of: 2024/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	1,338,396
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	0
12	Ending Balance Amount	1,338,396
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	925,223,351
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	160,000,895
16	Ending Balance Amount	1,085,224,246
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	1,086,562,642

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	9,924,450
22	TOTAL	9,924,450

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	Variable Rate Demand Exempt Facilities Bonds - 1993		15,500,000		275,796			10/14/1993	10/01/2028	10/14/1993	10/01/2028	15,500,000	546,722
3	Variable Rate Demand Exempt Facilities Bonds - 1994		30,000,000		440,787			10/10/1994	10/01/2029	10/10/1994	10/01/2029	30,000,000	1,025,130
4	Variable Rate Demand Exempt Facilities Bonds - 1999		22,330,000		334,028			07/01/1999	07/01/2024	07/01/1999	07/01/2024		421,586
5	Variable Rate Demand Exempt Facilities Bonds - 1999		11,000,000					07/01/1999	07/01/2024	07/01/1999	07/01/2024		210,398
6	4% First Mortgage Bonds due 6/1/2042		250,000,000		2,187,500		512,500	06/26/2012	06/01/2042	06/26/2012	06/01/2042	250,000,000	10,000,000
7	4.15% First Mortgage Bonds due 5/15/2045		200,000,000		2,313,720		172,000	05/11/2015	05/15/2045	05/11/2015	05/15/2045	200,000,000	8,300,000
8	4.15% First Mortgage Bonds due 5/15/2045		175,000,000		1,531,250	(775,250)		12/12/2016	05/15/2045	12/12/2016	05/15/2045	175,000,000	7,262,500
9	4.27% First Mortgage Bonds due 6/15/2048		200,000,000		1,763,969			06/21/2018	06/15/2048	06/21/2018	06/15/2048	200,000,000	8,540,000
10	4.14% First Mortgage Bonds due 12/12/2049		75,000,000		763,717			12/12/2019	12/12/2049	12/12/2019	12/12/2049	75,000,000	3,105,000
11	2.53% First Mortgage Bonds due 6/9/2030		100,000,000		793,037			06/09/2020	06/09/2030	06/09/2020	06/09/2030	100,000,000	2,530,000
12	3.24% First Mortgage Bonds due 3/30/2051		125,000,000		1,010,021			03/30/2021	03/30/2051	03/30/2021	03/30/2051	125,000,000	4,050,000
13	3.06% First Mortgage Bonds due		125,000,000		1,025,116			02/15/2022	02/15/2052	02/15/2022	02/15/2052	125,000,000	3,825,000

	2/15/2052												
14	5.30% First Mortgage Bond due 3/15/2033		60,000,000		619,307			03/15/2023	03/15/2033	03/15/2023	03/15/2033	60,000,000	3,180,000
15	5.57% First Mortgage Bond due 3/15/2053		65,000,000		666,068			03/15/2023	03/15/2053	03/15/2023	03/15/2053	65,000,000	3,620,500
16	5.45% First Mortgage Bond due 11/8/2033		340,000,000		2,227,664			11/08/2023	11/08/2033	11/08/2023	11/08/2033	340,000,000	18,530,000
17	5.55% First Mortgage Bond due 11/8/2038		75,000,000		491,305			11/08/2023	11/08/2038	11/08/2023	11/08/2038	75,000,000	4,162,500
18	5.72% First Mortgage Bond due 11/8/2058		110,000,000		720,707			11/08/2023	11/08/2053	11/08/2023	11/08/2053	110,000,000	6,292,000
19	5.24% First Mortgage Bond due 3/20/2034		100,000,000		779,483			[(a)] 03/20/2024	03/20/2034	03/20/2024	03/20/2034	100,000,000	4,090,111
20	5.55% First Mortgage Bond due 3/20/2054		75,000,000		589,544			[(b)] 03/20/2024	03/20/2054	03/20/2024	03/20/2054	75,000,000	3,249,063
21	Tax Exempt Bonds		78,400,000		851,895			07/01/2020	07/01/2025	07/01/2020	07/01/2025	78,400,000	823,200
22	Subtotal		2,232,230,000		19,384,914	(775,250)	684,500					2,198,900,000	93,763,709
23	Reacquired Bonds (Account 222)												
24													
25													
26													
27	Subtotal												
28	Advances from Associated Companies (Account 223)												
29													
30													
31													
32	Subtotal												
33	Other Long Term Debt (Account 224)												
34	Medium Term Notes 7.72% Series C		10,000,000					02/07/1997	02/01/2027	02/07/1997	02/01/2027	10,000,000	772,000
35	Subtotal		10,000,000									10,000,000	772,000
33	TOTAL		2,242,230,000									2,208,900,000	[(c)]94,535,709

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NominalDateOfIssue

$100 million of First Mortgage Bonds were issued on March 20, 2024.

(b) Concept: NominalDateOfIssue

$75 million of First Mortgage Bonds were issued on March 20, 2024.

(c) Concept: InterestExpenseOnLongTermDebtIssued

The difference between the total interest reported in column (m) and the balances in account 427 and 430 is $38,609 which represents Service Company related interest from money pool transactions and credit facility commitment fees each of which are reported in account 430.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a

footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	208,821,971
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Federal & State Income Tax	48,972,611
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	SEE FOOTNOTE	[a](141,451,450)
27	Federal Tax Net Income	116,343,132
28	Show Computation of Tax:	
29	Federal Income Tax at 21%	24,432,058
30	SEE FOOTNOTE	4,739,407
31	TOTAL	29,171,465
32	Federal Income Tax Acct 409.10	27,015,891
33	Federal Income Tax Acct 409.20	2,155,574
34	Total	29,171,465

FOOTNOTE DATA

(a) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Net Income for the Year (Page 117)	$	208,821,971
Federal Income Taxes		32,140,911
State Income Taxes		16,831,700
Pre-tax Book Income	$	257,794,582
Increase (Decrease) in Taxable Income Resulting From:		
Removal Costs	$	(55,674,048)
Mixed Service Costs		(48,978,512)
Repair Allowance - Unit of Property		(61,814,952)
Bonus Depreciation		—
Depreciation		31,578,551
CIAC		22,561,611
AFUDC Equity		(11,777,950)
AFUDC Debt		(6,846,422)
Capitalized Interest		9,896,136
Gain/Loss on Disposition of Property		(3,024,989)
Other (Property)		19,860,166
Regulatory Assets & Liabilities		(13,377,512)
Pension/OPEB/SERP		5,050,728
Accrued Liabilities		(83,743)
Merger Commitment Deferrals		—
State Income Taxes Deductible		(3,812,088)
Deferred Revenue		(531,316)
Other (Net)		(24,477,110)

Total Schedule M's	$	(141,451,450)
Federal Taxable Income		116,343,132
Computation of Federal Income Tax:		
Federal Income Tax on Current Year Income (21%)	$	24,432,058
Corporate Alternative Minimum Tax Adjustment		4,077,975
Net Operating Loss Utilized		—
Return to Accrual True Up		1,342,273
Amended Return Adjustments		—
State Notice Payment or Refund		—
Income Tax Credits		(680,841)
Federal Income Tax	$	29,171,465
Federal Income Tax Account 409.10	$	27,015,891
Federal Income Tax Account 409.20		2,155,574
Total	$	29,171,465

Additional information in response to Instruction 2, Page 261:

The Respondent is a wholly owned subsidiary of Exelon Corporation. The Respondent files a consolidated tax return with Exelon Corporation and Exelon Corporation's other subsidiaries. The consolidated federal income tax liability was allocated to the Respondent on a separate-return basis.

Corporate Alternative Minimum Tax Adjustment: This adjustment represents the difference between regular tax calculated at 21% of taxable income to the Corporate Alternative Minimum Tax calculated at 15% of Adjusted Financial Statement Income.

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1					0	0				0					
2	**Subtotal Federal Tax**				0	0				0	0				
3	**Subtotal State Tax**				0	0				0	0				
4	**Subtotal Local Tax**				0	0				0	0				
5	Public Service Commission (PSC)	Other Taxes	MD	2024	0	0	1,396,463	1,396,463		0		1,396,463			
6	Reg Asset Assessment - Electric	Other Taxes	DE	2024	1,800,505	0	2,962,338	2,361,610		2,401,233		2,962,338			
7	Reg Asset Assessment - Gas	Other Taxes	DE	2024	91,932	0	682,956	576,133		198,755					682,956
8	Environmental Surcharge	Other Taxes	MD	2024	55,311	0	620,463	617,497		58,277		620,463			
9	Other Taxes	Other Taxes	MD	2024						0					
10	GRT/Professional Services - Electric	Other Taxes	DE	2024	48,271	0	690,488	681,029		57,730		690,488			
11	GRT/Professional Services - Electric Reserve	Other Taxes	DE	2024		0									
12	GRT/Professional Services - Gas	Other Taxes	DE	2024	2,368	0	25,891	26,318		1,941					25,891
13	Public Utility Tax - Electric	Other Taxes	DE	2024	685,373	0	8,432,145	8,420,648		696,870		8,432,145			
14	Public Utility Tax - Gas	Other Taxes	DE	2024	249,376	0	2,277,777	2,240,050		287,103					2,277,777
15	**Subtotal Other Tax**				2,933,136		17,088,521	16,319,748		3,701,909		14,101,897			2,986,624
16	Property Taxes	Property Tax	MD	2024		12,746,731	23,471,511	26,975,638	[(b)]3,274,634	0	12,976,224	23,471,511			

17	Property Taxes - Other	Property Tax	MD	2024	32,234	0		(36,954)	[c](34,594)	34,594					
18	Property Taxes	Property Tax	DE	2024	0	11,527,816	23,392,861	25,495,552	[d]973,163	0	12,657,344	13,808,355			9,584,506
19	Property Taxes	Property Tax	VA	2024	0	0	146,842	145,552	[e](1,290)	0		146,842			
20	Property Taxes	Property Tax	WV	2024	0	0	17,929	17,929		0					17,929
21	Property Taxes	Property Tax	MS	2024		0	20,278	20,278		0					20,278
22	Property Taxes	Property Tax	NJ	2024	0	0	684,478	684,478		0					684,478
23	Property Taxes	Property Tax	PA	2024	0	43,099		109,832	[f]108,617	0	44,314				
24	**Subtotal Property Tax**				32,234	24,317,646	47,733,899	53,412,305	4,320,530	34,594	25,677,882	37,426,708			10,307,191
25	**Subtotal Real Estate Tax**				0	0				0	0				
26	**Subtotal Unemployment Tax**				0	0				0	0				
27	Sales Tax	Sales And Use Tax	MD	2024	0	0	(15,145)	(15,145)		0		(15,145)			
28	Use Tax	Sales And Use Tax	MD	2024	1,066,737	0		(316,992)		1,383,729					
29	Use Tax Reserve	Sales And Use Tax	MD	2024	719,587	0	53,704	(15,869)		789,160		53,704			
30	Use Tax	Sales And Use Tax	VA	2024	112,186	0		66,716		45,470					
31	**Subtotal Sales And Use Tax**				1,898,510	0	38,559	(281,290)		2,218,359	0	38,559			
32	Federal Income Tax	Income Tax	Fed	2024	17,507,932	0	29,171,465	43,260,827		3,418,570		22,454,750			6,716,715
33	State Income Tax - Delaware	Income Tax	DE	2024	6,012,138	0	4,497,942	13,382,519	[g]2,872,439			3,366,242			1,131,700
34	State Income Tax - Maryland	Income Tax	MD	2024	0	0				0					
35	**Subtotal Income Tax**				23,520,070	0	33,669,407	56,643,346	2,872,439	3,418,570	0	25,820,992			7,848,415
36	Heavy Highway Excise Tax	Excise Tax	Fed	2024	0		12,652	12,652		0		8,280			4,372
37	**Subtotal Excise Tax**				0		12,652	12,652		0	0	8,280			4,372
38	**Subtotal Fuel Tax**				0	0				0	0				
39	**Subtotal Federal Insurance Tax**				0	0				0	0				
40	Franchise Tax	Franchise Tax	MD	2024	120,507		9,551,116	9,605,094		66,529		9,551,116			
41	Wilmington Franchise Tax	Franchise Tax	DE	2024	889,527	0	905,163	900,899		893,791		905,163			
42	Wilmington Franchise Tax Reserve	Franchise Tax	DE	2024		0									
43	**Subtotal Franchise Tax**				1,010,034		10,456,279	10,505,993		960,320	0	10,456,279			
44	**Subtotal Miscellaneous Other Tax**				0	0				0	0				
45	**Subtotal Other Federal Tax**				0	0				0	0				
46	**Subtotal Other State Tax**				0	0				0	0				
47	**Subtotal Other Property Tax**				0	0				0	0				
48	**Subtotal Other Use Tax**				0	0				0	0				
49	**Subtotal Other Advalorem Tax**				0	0				0	0				
50	**Subtotal Other License And Fees Tax**				0	0				0	0				
51	Payroll Taxes	Payroll Tax	[a] Various	2024	1,155,319	0	3,807,103	3,356,549		1,605,873		3,182,644			624,459
52	**Subtotal Payroll Tax**				1,155,319	0	3,807,103	3,356,549		1,605,873	0	3,182,644			624,459
53	**Subtotal Advalorem Tax**				0	0				0	0				
54	**Subtotal Other Allocated Tax**				0	0				0	0				
55	**Subtotal Severance Tax**				0	0				0	0				
56	**Subtotal Penalty Tax**				0	0				0	0				
57	**Subtotal Other Taxes And Fees**				0	0				0	0				
40	TOTAL				30,549,303	24,317,646	112,806,420	139,969,303	7,192,969	11,939,625	25,677,882	91,035,359			21,771,061

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FOOTNOTE DATA

(a) Concept: TaxJurisdiction

Payroll tax is applicable to following jurisdictions: Federal, Delaware, Maryland, Massachusetts, New Jersey, Pennsylvania and Virginia.

(b) Concept: TaxAdjustments

Adjustments to Property Taxes	Amount
Reclassification to FERC Account 184	$ 3,240,040
Property Tax Reclassification	34,594
Total Adjustments to Maryland Property Taxes	$ 3,274,634

(c) Concept: TaxAdjustments

Adjustments to Property Taxes - Other	Amount
Property Tax Reclassification	$ (34,594)
Total Adjustments to Property Taxes - Other	$ (34,594)

(d) Concept: TaxAdjustments

Adjustments to Property Taxes	Amount
Reclassification to FERC Account 184	$ 973,163
Total Adjustments to Property Taxes	$ 973,163

(e) Concept: TaxAdjustments

Adjustments to Property Taxes	Amount
Reclassification to FERC Account 184	$ (1,290)
Total Adjustments to Property Taxes	$ (1,290)

(f) Concept: TaxAdjustments

Adjustments to Property Taxes	Amount
Reclassification to FERC Account 184	$ 108,617
Total Adjustments to Property Taxes	$ 108,617

(g) Concept: TaxAdjustments

Adjustments to State Income Tax	
Reclassification to FERC Account 143	$ 2,872,439
Total Adjustments to State Income Tax	$ 2,872,439

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
1	Electric Utility									
2	3%									
3	4%	4,392			411.4	991		3,401		
4	7%	215,470			411.4	48,613		166,857		
5	10%	564,739			411.4	127,414		437,325		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	784,601				177,018		607,583		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
11	10% Gas Utility	48,819				14,034		34,785		
12	Total Other	48,819				14,034		34,785		
13	Account 255	833,420				191,052		642,368		
47	OTHER TOTAL									

48	GRAND TOTAL	833,420						642,368		

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OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Special Billing	2,575,574	454	2,637,133	3,007,914	2,946,355
2	DE Charitable Contributions	894,148	426.1	869,813		24,335
3	MD Charitable Contributions	236,517	426.1	236,517		
4	MFN Credits	213,782				213,782
5	Supplier Deposits	531,461	232	54,777	23,124	499,808
6	[a] Merrill Creek Lease	9,826,542	418	4,288,077	4,027,042	9,565,507
7	[b] Tower Attachment Agreements	12,295,989	454	531,316	446,264	12,210,937
8	Maryland Interconnectivity Fee	394,181	456	394,181		
9	Deferred Rent	1,705,695	[c] various	60,263		1,645,432
10	Other	168,747	186	153,071	111,482	127,158
47	TOTAL	28,842,636		9,225,148	7,615,826	27,233,314

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FOOTNOTE DATA

(a) Concept: DescriptionOfOtherDeferredCredits

Merrill Creek Lease credit will be amortized through 2038.

(b) Concept: DescriptionOfOtherDeferredCredits

The Tower Attachment Agreements balance will be amortized and recognized as operating revenue over the 35 years under the collaborative arrangement. Refer to Note 3 "Revenue from Contracts with Customers" of accompanying "Notes to Financial Statements" for a discussion on the Contract Liabilities for the Tower Attachment Agreements.

(c) Concept: DecreaseInOtherDeferredCreditsContraAccount

Deferred Rent is offset in Accounts 186 and 418.

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ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR Amounts Credited to Account 411.2 (f)	ADJUSTMENTS Debits Account Credited (g)	ADJUSTMENTS Debits Amount (h)	ADJUSTMENTS Credits Account Debited (i)	ADJUSTMENTS Credits Amount (j)	Balance at End of Year (k)

1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities										
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)										
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)										
18	Classification of TOTAL										
19	Federal Income Tax										
20	State Income Tax										
21	Local Income Tax										

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 282										
2	Electric	852,727,050	33,905,015	25,542,954			254, 410, 411		254, 410, 411	16,166,339	877,255,450
3	Gas	94,747,450	3,765,175	3,764,668			254, 410, 411		254, 410, 411	2,724,871	97,472,828
4	Other (Specify)										
5	Total (Total of lines 2 thru 4)	[(a)]947,474,500	37,670,190	29,307,622						18,891,210	[(b)]974,728,278
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	947,474,500	37,670,190	29,307,622						18,891,210	974,728,278
10	Classification of TOTAL										
11	Federal Income Tax	681,779,987	26,149,015	25,401,408			254, 410, 411		254, 410, 411	17,144,183	699,671,777
12	State Income Tax	265,694,513	11,521,175	3,906,214			254,		254,	1,747,027	275,056,501

							410, 411		410, 411		
13	Local Income Tax										

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

282		Electric	Gas	Total
Plant Related Deferred Taxes	$	870,379,357 $	96,708,818 $	967,088,175
Contribution in Aid of Construction		(21,137,048)	(2,348,561)	(23,485,609)
AFUDC Equity		13,960,511	1,551,168	15,511,679
Plant Deferred Taxes - Flow-through		6,548,302	727,589	7,275,891
Maryland Subtraction Modification		(17,024,072)	(1,891,564)	(18,915,636)
Total	$	852,727,050 $	94,747,450 $	947,474,500

(b) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

282		Electric	Gas	Total
Plant Related Deferred Taxes	$	892,775,321 $	99,197,258 $	991,972,579
Contribution in Aid of Construction		(22,753,430)	(2,528,159)	(25,281,589)
AFUDC Equity		16,422,027	1,824,670	18,246,697
Plant Deferred Taxes - Flow-through		7,705,908	856,212	8,562,120
Maryland Subtraction Modification		(16,894,376)	(1,877,153)	(18,771,529)
Total	$	877,255,450 $	97,472,828 $	974,728,278

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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance at End of Year (k)
							Debits		Credits		
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Electric	77,820,634	6,211,846	6,918,799			254, 410, 411		254, 410, 411		77,113,681
4							254, 410, 411		254, 410, 411		
9	TOTAL Electric (Total of lines 3 thru 8)	[(a)]77,820,634	6,211,846	6,918,799							[(b)]77,113,681
10	Gas										
11	Gas	8,953,294	783,496	987,889			254, 410, 411		254, 410, 411		8,748,901
12							254, 410, 411		254, 410, 411		
17	TOTAL Gas (Total of lines 11 thru 16)	8,953,294	783,496	987,889							8,748,901
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	86,773,928	6,995,342	7,906,688							85,862,582
20	Classification of TOTAL										
21	Federal Income Tax	60,160,961	4,849,918	5,481,761			254, 410, 411		254, 410, 411		59,529,118
22	State Income Tax	26,612,967	2,145,424	2,424,927			254, 410, 411		254, 410, 411		26,333,464

23	Local Income Tax										

NOTES

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

283	Electric	Gas	Total
Accrued Property Taxes	$ 5,780,866	$ 941,071	$ 6,721,937
Asset Retirement Obligation	523,368	85,199	608,567
Materials Reserve	(209,265)	(34,066)	(243,331)
Other Deferred Debits	2,450,687	398,949	2,849,636
Pension Asset	32,273,532	5,253,831	37,527,363
Regulatory Asset	33,139,179	2,049,730	35,188,909
Regulatory Asset - Accrued Vacation	831,940	135,432	967,372
Renewable Energy Credits	2,273,845	—	2,273,845
Unamortized Loss on Reacquired Debt	756,482	123,148	879,630
Total	$ 77,820,634	$ 8,953,294	$ 86,773,928

(b) Concept: AccumulatedDeferredIncomeTaxesOther

283	Electric	Gas	Total
Accrued Property Taxes	$ 6,101,490	$ 993,266	$ 7,094,756
Asset Retirement Obligation	726,957	118,342	845,299
Materials Reserve	(276,967)	(45,088)	(322,055)
Other Deferred Debits	2,577,014	419,514	2,996,528
Pension Asset	28,736,501	4,678,035	33,414,536
Regulatory Asset	35,307,236	2,341,972	37,649,208
Regulatory Asset - Accrued Vacation	881,506	143,501	1,025,007
Renewable Energy Credits	2,449,595	—	2,449,595
Unamortized Loss on Reacquired Debt	610,349	99,359	709,708
Total	$ 77,113,681	$ 8,748,901	$ 85,862,582

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OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	[(a)] SFAS 109 Regulatory Liability: Electric	243,015,232	[(b)] Various	23,520,913		219,494,319
2	SFAS 109 Regulatory Liability: Gas	30,453,478	[(c)] Various	2,613,435		27,840,043
3	Maryland SOS: Energy	676,840	407.3	676,839		1
4	Delaware SOS: Transmission	251,804	N/A		1,235,194	1,486,998
5	Delaware SOS: Administrative Costs	1,303,122	N/A		299,725	1,602,847
6	DE Qualified Fuel Cell Facility	6,997,317	[(d)] Various	359,436	27,973	6,665,854
7	DE Deferred Fuel Costs-Gas	13,343,688	[(e)] Various	8,645,581	1,908,734	6,606,841
8	DE SFAS 133 Gas Derivatives		N/A		218,948	218,948
9	DE Distribution Rate Reserve	9,391,143	[(f)] Various	9,391,143		
10	MD Dynamic Pricing - Critical Peak Rebate Credits	333,614	407.3	311,234		22,380
11	Tax Cuts and Jobs Act	5,797,149	[(g)] Various	3,276,762	3,271,232	5,791,619
12	DSM Direct Load Control Program-MD	271,378	N/A		552,909	824,287
13	DSM-Energy Efficiency Products-MD	1,848,719	N/A		2,828,373	4,677,092
14	MD Bill Stabilization Adjustment Deferral	2,278,128	N/A		123,226	2,401,354
15	SOS Deferral for FERC 494 Settlement	867,943	407.3	439,869	13,298	441,372

16	DE DSM - Energy Efficiency	220,326	(h) Various	232,280	857,732	845,778
17	Transmission Service Revenue		456.1	7,470,137	7,470,137	
18	DE Incremental COVID-19 Cost	2,961,668	(i) Various	2,273,262		688,406
19	MD Incremental COVID-19 Cost	(42,047)	N/A	(42,047)		
20	Ocean City MD Land Swap Gain	1,680,060	N/A			1,680,060
21	MD Third Party Supplier Recovery	265,944	143	328,238	525,214	462,920
22	MD Multi-Year Plan Reconciliation	6,539,919	(j) Various	3,051,563	5,917,358	9,405,714
23	DE Electric Vehicle		N/A		371	371
41	TOTAL	328,455,425		62,548,645	25,250,424	291,157,204

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:

Line No.	Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism
3	Maryland SOS: Energy	MDPSC Case No. 8908
4	Delaware SOS: Transmission	DEPSC Docket No. 04-391
5	Delaware SOS: Administrative Costs	DEPSC Docket No. 04-391
6	DE Qualified Fuel Cell Facility	DEPSC Docket No. 12-173-04
7	DE Deferred Fuel Costs-Gas	DEPSC Docket No. 19-0556
9	DE Distribution Rate Reserve	DEPSC Docket No. 22-0897
10	MD Dynamic Pricing - Critical Peak Rebate Credits	MDPSC Case No. 9156
12	DSM Direct Load Control Program-MD	MDPSC Case No. 9156
13	DSM-Energy Efficiency Products-MD	MDPSC Case No. 9156
14	MD Bill Stabilization Adjustment Deferral	MDPSC Case No. 9092, MDPSC Case No. 9093
15	SOS Deferral for FERC 494 Settlement	FERC Docket No. EL05-121-009
16	DE DSM - Energy Efficiency	DEPSC Docket No. 17-0985
17	Transmission Service Revenue	FERC Docket No. ER05-515
18	DE Incremental COVID-19 Cost	DEPSC Docket No. 20-0286
19	MD Incremental COVID-19 Cost	MDPSC Case No. 9670
21	MD Third Party Supplier Recovery	MDPSC Maillog 116829
22	MD Multi-Year Plan Reconciliation	MD Case 9681

DPL amortizes its regulatory liabilities in account 254 based on the following amortization periods:

Line No.	Description of Other Regulatory Liabilities	Amortization Lives
15	SOS Deferral for FERC 494 Settlement	10 years
19	MD Incremental COVID-19 Cost	5 years

(b) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

The following are the individual components of "Various":

$	6,518,825	recorded to account 190
	3,332,844	recorded to account 282
	13,669,244	recorded to account 410/411
$	23,520,913	Total

(c) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

The following are the individual components of "Various":

$	724,314	recorded to account 190
	370,316	recorded to account 282
	1,518,805	recorded to account 410/411
$	2,613,435	Total

(d) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

The following are the individual components of "Various":

	924	recorded to account 928
	291,787	recorded to account 144 - Reclass of reserve on DE Qualified Fuel Cell activity
	66,725	recorded to account 407.3
$	359,436	Total

(e) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

The following are the individual components of "Various":

$	8,511,313	recorded to account 805.1
	134,268	recorded to account 431
$	8,645,581	Total

(f) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

The following are the individual components of "Various":

$	5,819,380	recorded to account 440
	1,699,600	recorded to account 442.001
	1,378,416	recorded to account 442.002
	278,088	recorded to account 444

	215,659	recorded to account 431
$	9,391,143	Total

(g) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

The following describes the balance sheet reclass:

$	29,541	recorded to account 407.3
	3,247,221	recorded to account 254.0 reclass included in Tax Cuts and Jobs Act line 25, pg. 232
$	3,276,762	Total

(h) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

The following describes the balance sheet reclass:

$	232,105	Recorded to account 182.3-reclass consistent with regulatory recovery position. DE DSM - Energy Efficiency line 10, page 232
	175	Recorded to account 920 - Write off
$	232,280	Total

(i) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

The following are the individual components of "Various":

$	348,108	recorded to account 904
	1,925,154	recorded to account 182.3-reclass included in DE Incremental COVID-19 Cost line 27, pg. 232
$	2,273,262	Total

(j) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

The following are the individual components of "Various":

$	1,904,723	recorded to account 440
	558,514	recorded to account 442.001
$	588,326	recorded to account 442.002
$	3,051,563	Total

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Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	942,722,978	826,739,223	5,371,248	5,131,740	488,409	483,949
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	352,640,511	348,388,261	5,174,612	5,002,290	65,541	64,948
5	Large (or Ind.) (See Instr. 4)	21,741,061	24,383,548	1,306,956	1,420,472	242	254
6	(444) Public Street and Highway Lighting	17,279,285	15,506,920	42,748	43,724	597	594
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	1,334,383,835	1,215,017,952	11,895,564	11,598,226	554,789	549,745
11	(447) Sales for Resale	10,334,576	10,967,520	350,893	446,324		
12	TOTAL Sales of Electricity	1,344,718,411	1,225,985,472	12,246,457	12,044,550	554,789	549,745
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	1,344,718,411	1,225,985,472	12,246,457	12,044,550	554,789	549,745
15	Other Operating Revenues						
16	(450) Forfeited Discounts	3,302,657	3,407,772				

17	(451) Miscellaneous Service Revenues	[(a)]1,314,901	917,558				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	7,957,897	7,751,138				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[(b)]11,629,112	13,835,400				
22	(456.1) Revenues from Transmission of Electricity of Others	243,994,966	233,818,525				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	268,199,533	259,730,393				
27	TOTAL Electric Operating Revenues	1,612,917,944	1,485,715,865				

Line12, column (b) includes $ 8,139,288 of unbilled revenues.
Line12, column (d) includes 18,375 MWH relating to unbilled revenues

Name of Respondent:	This report is:	Date of Report:	Year/Period of Report
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FOOTNOTE DATA

(a) Concept: MiscellaneousServiceRevenues

Items greater than $250,000

Connect Charges	$	1,174,610

(b) Concept: OtherElectricRevenue

Amounts over $250,000

Intercompany Revenue	$	5,574,860
Price Responsive Demand Credit		1,969,443
MD Interconnection Fees		1,143,262
Intracompany Power Sales		1,051,523
MD Calendar Revenue Normalization		(563,226)
Intercompany Power Sales		528,786
MD Bill Stabilization Adjustment		440,299
Third Party Account Management Fees		341,000
RPM Auction		254,409

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REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales					

2	Residential	4,255,823	762,685,256	398,378	10,683	0.1792
3	Residential Time Of Use					
4	Residential Time Of Use - Non Demand	1,554	232,431	115	13,504	0.1496
5	Outdoor Lighting - Residential	6,578	2,506,251	4,204	1,565	0.3810
6	Residential Space Heating	1,072,065	165,703,386	89,365	11,996	0.1546
7	Residential Time-of-Use (TOU) Pilot	5,456	1,088,728	512	10,657	0.1996
8	Plug in Vehicle - Residential	554	103,318	50	11,003	0.1866
9	Small General Service	47	3,972			0.0844
10	Medium General Service	8	24			0.0029
11	Unbilled Revenue	29,163	6,639,026			0.2276
12	DE Interim rates subject to refund		5,819,380			
13	DE DSIC revenue subject to refund					
14	Public Utility Tax Surcharge Revenue					
15	Adjustments - Duplicate Customers			(4,215)		
16	Energy Credits		(2,058,729)			
17	Misc		(65)			
41	TOTAL Billed Residential Sales	5,342,085	936,083,952	488,409	10,938	0.1752
42	TOTAL Unbilled Rev. (See Instr. 6)	29,163	6,639,026			0.2277
43	TOTAL	5,371,248	942,722,978	488,409	10,997	0.1755

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
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3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	442 - Commercial					
2	Small General Service	1,071,744	142,885,845	54,568	19,641	0.1333
3	Unmetered Small General Service	345	90,913	219	1,580	0.2639
4	Separately Metered Space Heating	69,949	6,227,095	2,263	30,904	0.0890
5	Separately Metered Water Heating	557	59,229	97	5,723	0.1063
6	Medium General Service	1,165,444	88,708,972	8,611	135,345	0.0761
7	Unmetered Medium General Service	36	17,994	15	2,424	0.4949
8	Large General Service	823,995	38,639,449	570	1,446,240	0.0469
9	General Services Primary	1,999,557	59,190,764	574	3,483,549	0.0296
10	Commercial Outdoor Lighting	11,749	4,940,975	3,750	3,133	0.4206
11	Commercial Outdoor Recreational Lighting	1,118	192,280	74	15,091	0.1720
12	Telecommunications Network Svc	3,594	279,261	924	3,889	0.0777
13	Residential			0		
14	Unbilled Revenue	26,524	1,911,753			0.0721
15	DE Interim rates subject to refund		2,807,729	0		

16	DE DSIC revenue subject to refund			0		
17	Public Utility Tax Surcharge Revenue		8,051,544			
18	Adjustments - Duplicate Customers			(6,124)		
19	Energy Credits & Billed BSA		(1,363,292)	0		
41	TOTAL Billed Small or Commercial	5,148,088	350,728,758	65,541	78,548	0.0681
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	26,524	1,911,753			0.0721
43	TOTAL Small or Commercial	5,174,612	352,640,511	65,541	78,952	0.0681

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	(442) Industrial					
2	Small General Service	5,042	525,851	91	55,106	0.1043
3	Medium General Service	7,237	486,622	35	209,779	0.0672
4	Large General Service	31,713	1,354,012	16	1,982,092	0.0427
5	General Services Primary	747,246	16,847,523	91	8,174,062	0.0225
6	General Services Transmission	552,870	2,343,148	9	61,430,002	0.0042
7	Industrial Outdoor Lighting	275	70,653	41	6,802	0.2565
8	Separately Metered Space Heating					
9	Unbilled Revenue	(37,427)	(483,573)			0.0129
10	DE Interim rates subject to refund		270,287			
11	DE DSIC revenue subject to refund					
12	Public Utility Tax Surcharge Revenue		326,538			
13	Adjustments - Duplicate Customers			(41)		
14	Energy Credits					
41	TOTAL Billed Large (or Ind.) Sales	1,344,383	22,224,634	242	5,555,302	0.0165
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(37,427)	(483,573)			0.0129
43	TOTAL Large (or Ind.)	1,306,956	21,741,061	242	5,391,362	0.0166

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	444 - Public Street & Highway Lght					
2	Outdoor Lighting	42,633	16,893,271	597	71,381	0.3963
3	DE Interim rates subject to refund		278,088			
4	DE DSIC revenue subject to refund					
5	Unbilled Revenue	115	72,082			0.6242
6	Public Utility Tax Surcharge Revenue		35,844			
41	TOTAL Billed Public Street and Highway Lighting	42,633	17,207,203	597	71,412	0.4036
42	TOTAL Unbilled Rev. (See Instr. 6)	115	72,082			0.3264
43	TOTAL	42,748	17,279,285	597	71,574	0.4042

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	11,877,189	1,326,244,547	554,789	21,408	0.1117
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	18,375	8,139,288			0.4430
43	TOTAL - All Accounts	11,895,564	1,334,383,835	554,789	21,442	0.1122

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

   AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW) Average Monthly NCP Demand (e)	ACTUAL DEMAND (MW) Average Monthly CP Demand (f)	Megawatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)
1	PECO Energy	RQ	2				826		40,470		40,470
2	PJM Interconnection	OS	PJM				350,067		10,294,106		10,294,106
15	Subtotal - RQ						826		40,470		40,470
16	Subtotal-Non-RQ						350,067		10,294,106		10,294,106
17	Total						350,893		10,334,576		10,334,576

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)		
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		

27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of Lines 62 thru 67)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		

71	(553) Maintenance of Generating and Electric Plant		
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	686,727,133	592,123,186
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	(8,196)	(17,091)
78	(557) Other Expenses	31,511,867	32,087,370
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	718,230,804	624,193,465
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	718,230,804	624,193,465
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	9,027,227	9,014,865
85	(561.1) Load Dispatch-Reliability		120,018
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	214,632	537,686
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	(2,544)	4,527
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	(2,576)	(3,232)
93	(562) Station Expenses		
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses		76,605
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	4,717,896	4,127,914
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	13,954,635	13,878,383
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	657,416	707,481
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	5,737,925	9,442,637
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	3,962,115	4,486,981
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	367,653	388,842
111	TOTAL Maintenance (Total of Lines 101 thru 110)	10,725,109	15,025,941
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	24,679,744	28,904,324
113	3. REGIONAL MARKET EXPENSES		

114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	25,107	9,344
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	25,107	9,344
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)	25,107	9,344
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,814,971	1,331,874
135	(581) Load Dispatching	3,164,832	3,548,573
136	(582) Station Expenses	7,099	125,419
137	(583) Overhead Line Expenses	1,598,455	2,657,085
138	(584) Underground Line Expenses	4,559,122	2,551,098
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	349,462	407,211
140	(586) Meter Expenses	3,053,972	3,901,067
141	(587) Customer Installations Expenses	617,620	540,377
142	(588) Miscellaneous Expenses	18,433,081	21,005,994
143	(589) Rents	1,867,024	1,961,655
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	35,465,638	38,030,353
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures	386,886	499,645
148	(592) Maintenance of Station Equipment	4,515,368	5,002,594
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	41,123,091	48,364,196
150	(594) Maintenance of Underground Lines	3,614,585	3,559,774
151	(595) Maintenance of Line Transformers	878,726	692,690
152	(596) Maintenance of Street Lighting and Signal Systems	1,590,107	1,788,474
153	(597) Maintenance of Meters	1,504,511	1,099,217
154	(598) Maintenance of Miscellaneous Distribution Plant	1,115,734	1,029,791
155	TOTAL Maintenance (Total of Lines 146 thru 154)	54,729,008	62,036,381
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	90,194,646	100,066,734

157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	1,995,776	1,093,654
161	(903) Customer Records and Collection Expenses	51,229,973	49,426,177
162	(904) Uncollectible Accounts	9,548,992	8,992,800
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	62,774,741	59,512,631
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	19,271,575	11,430,301
169	(909) Informational and Instructional Expenses	313,290	132,845
170	(910) Miscellaneous Customer Service and Informational Expenses	232,513	152,536
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	19,817,378	11,715,682
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses	446	
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	446	
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	3,501,102	2,572,698
182	(921) Office Supplies and Expenses	7,057,206	5,300,525
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	79,595,105	71,844,572
185	(924) Property Insurance	686,016	660,521
186	(925) Injuries and Damages	424,525	264,868
187	(926) Employee Pensions and Benefits	9,141,478	11,023,583
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	1,394,525	2,068,028
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	836,691	549,663
192	(930.2) Miscellaneous General Expenses	7,138,830	7,127,767
193	(931) Rents		
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	109,775,478	101,412,225
195	Maintenance		
196	(935) Maintenance of General Plant	468,432	1,113,991
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	110,243,910	102,526,216
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,025,966,776	926,928,396

	(2) A Resubmission		

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES MegaWatt Hours Received (i)	POWER EXCHANGES MegaWatt Hours Delivered (j)	COST/SETTLEMENT OF POWER Demand Charges ($) (k)	COST/SETTLEMENT OF POWER Energy Charges ($) (l)	COST/SETTLEMENT OF POWER Other Charges ($) (m)	COST/SETTLEMENT OF POWER Total (k+l+m) of Settlement ($) (n)
1	PJM Interconnection, LLC	EX	PJM Tariff				314,712				34,256	1,464,993	(t) 100,767,360	102,266,609
2	Axpo U.S. LLC	(b) OS					423,833					25,392,304		25,392,304
3	Constellation Energy Resources, LLC	(c) OS					1,613,366					121,877,614		121,877,614
4	DTE Energy Trading, Inc.	(d) OS					1,381,803					114,764,783		114,764,783
5	Hartree Partners, LP	(e) OS					1,371,469					101,971,186		101,971,186
6	Next Era Energy Power Marketing, LLC	(f) OS					800,731					66,130,767		66,130,767
7	Shell Energy North America US, LP	(g) OS					632,929					63,733,228		63,733,228
8	TransAlta Energy Marketing (U.S.) Inc.	(h) OS					82,850					4,470,330		4,470,330
9	Vitol Inc.	(i) OS					340,984					24,884,176		24,884,176
10	(a) PECO Borderline	(j) OS					164					8,076		8,076
11	Peak Energy Savings Credit	(k) (l) OS									54			54
12	Community Renewable Energy Facility	OS											(u) 2,960,466	2,960,466
13	AES Armenia Mountain Wind, LLC	(m) IU					112,637					7,655,788		7,655,788
14	Chestnut Flats Wind, LLC	(n) LU					90,143					6,084,475		6,084,475
15	Synergenics Roth Rock Wind Energy,	(o)					93,855					6,384,151		6,384,151

	LLC	LU												
16	Other RECs	(p) OS										27,292,886		27,292,886
17	TFS Energy Futures LLC	OS											(t) 3,750	3,750
18	BET MD	(q) OS					34,629					3,166,234		3,166,234
19	Other NEM	(r) OS										7,675,600		7,675,600
20	RECs	(s) OS										4,656		4,656
15	TOTAL						7,294,105	0	0	0	34,310	582,961,247	103,731,576	686,727,133

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

PECO Energy Company and Delmarva Power and Light Company were both subsidiaries of Exelon Corporation as of December 31, 2024.

(b) Concept: StatisticalClassificationCode

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

(c) Concept: StatisticalClassificationCode

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

(d) Concept: StatisticalClassificationCode

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

(e) Concept: StatisticalClassificationCode

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

(f) Concept: StatisticalClassificationCode

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

(g) Concept: StatisticalClassificationCode

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

(h) Concept: StatisticalClassificationCode

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

(i) Concept: StatisticalClassificationCode

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

(j) Concept: StatisticalClassificationCode

Megawatt Hours which PECO customers consumed on PHI territory which was read by PHI but billed by PECO.

(k) Concept: StatisticalClassificationCode

Peak energy savings credit program designed to reduce energy usage during times of peak energy demand.

(l) Concept: StatisticalClassificationCode

Customer bill credits associated with the Community Renewable Energy Facility program in Maryland.

(m) Concept: StatisticalClassificationCode

Megawatt Hours purchased from Armenia Mountain Wind, LLC under Renewable Wind Energy Power Purchase Agreement (PPA). Termination Date : 12/19/2024

(n) Concept: StatisticalClassificationCode

Megawatt Hours purchased from Chestnut Flats Wind, LLC under Renewable Wind Energy Power Purchase Agreement (PPA). Termination Date : 12/29/2031

(o) Concept: StatisticalClassificationCode

Megawatt Hours purchased from Roth Rock Wind Farm, LLC under Renewable Wind Energy Power Purchase Agreement (PPA). Termination Date : 08/03/2031

(p) Concept: StatisticalClassificationCode

Represents net accruals for renewable energy credits in Delaware and Maryland.

(q) Concept: StatisticalClassificationCode

Megawatt Hours purchased from wholesale suppliers under Delmarva Power & Light Company's Standard Offer Service (SOS) program for Delaware and Maryland in accordance with the Full Requirements Service (FSA) Agreement.

(r) Concept: StatisticalClassificationCode

Megawatt Hours purchased from customers as a part of the Net Energy Metering Program.

(s) Concept: StatisticalClassificationCode

Represents net accruals for renewable energy credits in Delaware and Maryland.

(t) Concept: OtherChargesOfPurchasedPower

PJM Interconnection, LLC		
Balancing Operating Reserve	$	79,011
Balancing Operating Reserve for Load Response		—
Day-ahead Scheduling Reserve		—

Load Reconciliation for Balancing Operating Reserve	81
Load Reconciliation for Day-ahead Scheduling Reserve	—
Load Reconciliation for Non- Synchronized Reserve	(216)
Load Reconciliation for Reactive Services	—
Load Reconciliation for Regulation & Frequency Response Service	468
Load Reconciliation for Synchronized Reserve	221
Network Integration Transmission Service	100,686,840
Non- Synchronized Reserve	4
Reactive Services	22
Reactive Supply & Voltage Control	1,641
Regulation & Frequency Response Service	(817)
Secondary Reserve	7
Synchronized Reserve	98
PJM FERC Ordered Refund	—
Greenhat	—
	$ 100,767,360

(u) Concept: OtherChargesOfPurchasedPower

Customer bill credits associated with the Community Renewable Energy Facility program in Maryland.

(v) Concept: OtherChargesOfPurchasedPower

Represents broker fees on purchases of renewable energy credits.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

									TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	PJM Point to Point Trans Revenue	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	OATT								[a]200,889	200,889
2	PJM Trans Owner Sched, Sys Control												[b]1,469,995	1,469,995
3	PJM Network Integration Transmission Svc												[c]237,918,596	237,918,596
4	Other Transmission Agreements												[d]2,554,627	2,554,627
5	PJM Transmission Enhancement Credits												[e]1,850,859	1,850,859
6	AEP Energy, Inc (1678)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		24,687					
7	AEP Energy, Inc (6611)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		17,115					
8	AEP Energy, Inc. (1677)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		41,176					
9	Alpha Gas and Electric, LLC (6891)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		378					
10	Ambit Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,064					
11	Ambit Energy (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,243					
12	American Power & Gas of MD,	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL	DPL		8,662					

	LLC (6192)					SYSTEM	SYSTEM							
13	Atlantic Energy MD, LLC (5411)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,639					
14	Atlantic Energy, LLC (6710)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,069					
15	BOC Energy Services (313)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		186,740					
16	Brookfield Renewable Energy Marketing US LLC (7390)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		10,017					
17	Calpine Energy Solutions, LLC (332)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		217,871					
18	Champion Energy Services, LLC (2897)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		18,024					
19	Champion Energy Services, LLC (4260)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		26,887					
20	CleanChoice Energy (3697)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		8,197					
21	CleanChoice Energy (4024)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		29,324					
22	Clearview Electric (DE) (2237)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		7,061					
23	Clearview Electric (MD) (2238)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,006					
24	Commerce Energy (3598)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		18,381					
25	Commerce Energy, Inc.	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		13,586					
26	Constellation New Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		26,347					
27	Constellation New Energy (2817)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		78,436					
28	Constellation New Energy (2818)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		43,321					
29	Constellation NewEnergy, Inc. (5550)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		937,740					
30	Constellation NewEnergy, Inc. (5511)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		60,611					
31	Constellation NewEnergy, Inc. (5512)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		598,693					
32	CPV Retail Energy LP (7770)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		8,299					
33	CPV Retail Energy LP (7771)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		18,401					
34	Delmarva Power (DEN)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		(3,567)					
35	Delmarva Power (MDN)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		(49,864)					
36	Direct Energy Business (346)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		93,176					
37	Direct Energy Business Marketing (4461)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,623					
38	Direct Energy Business, (2837)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		434,511					
39	Direct Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		42,396					
40	Direct Energy Services (1777)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		23,199					
41	Discount Energy Group LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		184					
42	Discount Power, Inc. (7430)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,181					
43	DPLDEH (7570)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,828					

44	EDF Energy Services, LLC (5410)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,445					
45	EDF Energy Services, LLC (5430)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		84,605					
46	ELIGO	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		856					
47	Energy Harbor (520)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		36,243					
48	Energy Plus Holdings, LLC (2157)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,182					
49	Engie Resources (1317)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		326,382					
50	Engie Resources (2819)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,859					
51	Engie Resources (3038)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,004					
52	First Point Power, LLC (3037)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		159					
53	Freepoint Energy Solutions (6052)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		112,503					
54	Freepoint Energy Solutions, LLC (5790)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		60,644					
55	GEXA Energy Delaware, LLC (1398)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		200,275					
56	GEXA Energy Maryland, LLC. (1299)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		18,947					
57	Great American Power, LLC (3118)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		274					
58	Green Mountain Energy Company - MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		346					
59	Greenlight Energy, Inc (6670)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		172					
60	Greenlight Energy, Inc (7510)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		128					
61	Horizon Power & Light LLC (698)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		3,259					
62	Hudson Energy Services (6150)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		13,990					
63	IDT Energy, Inc. (3197)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,025					
64	Indra Energy (2637)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		529					
65	Indra Energy (5991)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,540					
66	Inspire Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,060					
67	Inspire Energy Holdings, LLC (6750)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		39,232					
68	Kuehne Chemical Co (597)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		73,536					
69	Major Energy Electric (4544)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,916					
70	Maryland Gas & Electric (3058)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,953					
71	MidAmerican Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		51,980					
72	MidAmerican Energy Services, LLC - DPLMD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		51,641					
73	MP2 Energy NE LLC (6230)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		20,678					
74	MP2 Energy NE LLC (6231)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		63,558					
75	New Wave Energy, LLC (8090)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL	DPL		33					

						SYSTEM	SYSTEM							
76	NextEra Energy Services Delaware, LLC (2178)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,591					
77	NextEra Energy Services Maryland, LLC (2179)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		212					
78	Nordic Energy Services (7750)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		243					
79	NORDIC ENERGY SERVICES, LLC (8070)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		737					
80	Park Power, LLC (6890)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,277					
81	PBF Power Marketing, LLC (3097)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		300,400					
82	Plymouth Rock Energy, LLC (3437)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		6					
83	Potomac Electric Power Company (MD HPS) (7030)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,149					
84	Public Power of MD (2317)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		10,366					
85	Reliant Energy Northeast LLC (2097)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		23,887					
86	Reliant Energy Northeast LLC (2319)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		50,956					
87	ResCom Energy LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		223					
88	Residents Energy, LLC (6091)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		15,698					
89	RPA Energy, Inc (7170)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		117					
90	RPA Energy, Inc. (6970)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		965					
91	Rushmore Energy, LLC (6790)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		11,078					
92	Rushmore Energy, LLC (7330)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,415					
93	SFE Energy Maryland, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		8,232					
94	SmartEnergy (5752)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		440					
95	SmartEnergy Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		21,304					
96	SmartestEnergy US LLC (7230)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		26,340					
97	SmartestEnergy US LLC (7231)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		41,292					
98	Spark Energy, LLC (4220)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,701					
99	StateWise Energy Maryland, LLC (6550)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		126					
100	Stream Energy Delaware, LLC (5831)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,082					
101	Stream Energy Maryland, LLC (2757)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,451					
102	Texas Retail Energy (2857)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		30,446					
103	Titan Gas, LLC (6430)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		10,318					
104	Titan Gas, LLC (7830)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,098					
105	Tomorrow Energy Corp (5510)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,664					
106	UGI Energy Services (522)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		19,260					

107	Washington Gas Energy Services (2618)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		71,730					
108	Washington Gas Energy Services (2620)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		111,854					
109	Washington Gas Energy Services (2622)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		153,137					
110	Washington Gas Energy Services (2626)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		653,980					
111	XOOM Energy Delaware, LLC - DE	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,869					
112	XOOM Energy Maryland, LLC - MD (4204)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		7,788					
35	TOTAL								5,770,028				243,994,966	243,994,966

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

DPL share of PJM pool Point-to-Point transmission revenue from the administration of the PJM Interconnection, LLC Open Access Transmission Tariff (OATT).

(b) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Revenue from PJM Interconnection, LLC for Transmission Owner Scheduling, System Control and Dispatch Service with the DPL Zone Control Center.

(c) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Revenue from the PJM Interconnection, LLC for Network Integration Transmission Service and Other Supporting Facilities, specifically, ODEC and DEMEC with DPL.

(d) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Revenue from Other Transmission Agreements, specifically, PSEG for LDV (Lower Delaware Valley).

(e) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Revenue from Transmission Enhancements.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					

12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
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40					
41					
42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.

3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		0	0	0	0	0	0

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	377,245
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Trustee Fees	192,491
7	Board of Director Expenses	82,637
8	Research, Development and Demonstration, including Memberships	89,273
9	DE Environmental & Low Income and MD Universal Fund	6,509,875
10	Credit card accruals	(112,691)
11	Miscellaneous	
46	TOTAL	7,138,830

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			15,317,084		15,317,084
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	55,671,776				55,671,776
8	Distribution Plant	94,595,540				94,595,540
9	Regional Transmission and Market Operation					
10	General Plant	18,047,153				18,047,153
11	Common Plant-Electric	5,063,206		7,311,067		12,374,273
12	TOTAL	173,377,675		22,628,151		196,005,826

B. Basis for Amortization Charges

Consistent with the preceding year, electric and common intangible Plant computer Software is amortized for a five year period using a straight line basis.

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Transmission						
13	350.2	33,659	75 years		0.87	R3	
14	352	116,891	70 years	(20)	1.66	R2	
15	353	772,425	42 years	(25)	3.18	S0.5	
16	354	75,301	75 years	(45)	1.21	R3	
17	355	729,751	43 years	(75)	3.77	R2.5	
18	356	374,925	55 years	(75)	3.18	R2	
19	357	6,506	60 years		1.26	R4	
20	358	63,117	55 years	(10)	1.71	R3	
21	359	1,111	65 years		0.54	R4	
22	SUBTOTAL	2,173,686					
23	Distribution						
24	360.2 DE	3,584	70 years		1.05	R4	
25	360.2 MD	4,086	60 years		1.07	R2	
26	361 DE	30,155	65 years	(10)	1.27	R4	
27	361 MD	33,613	60 years	(15)	1.78	R1.5	
28	362 DE	301,399	45 years	(20)	2.08	R2	

29	362 MD	276,404	45 years	(25)	2.59	R1.5		
30	364 DE	151,462	55 years	(100)	2.25	R2		
31	364 MD	148,939	55 years	(125)	2.94	R2		
32	365 DE	266,987	55 years	(100)	1.53	R1.5		
33	365 MD	285,738	57 years	(100)	2.23	R0.5		
34	366 DE	25,081	70 years	(5)	0.84	S3		
35	366 MD	1,319	55 years		1.25	R3		
36	367 DE	283,910	52 years	(40)	1.82	R3		
37	367 MD	225,305	48 years	(20)	2.29	R3		
38	368 DE	405,434	45 years	(50)	1.77	R2		
39	368 MD	327,928	36 years	(50)	3.61	R1		
40	369.1 DE	27,389	65 years	(120)	0.81	R4		
41	369.1 MD	10,351	65 years	(75)	2.73	R4		
42	369.2 DE	120,460	55 years	(60)	1.36	S3		
43	369.2 MD	99,736	50 years	(25)	1.88	R4		
44	370 DE	15,012	25 years	(3)	2.77	L0.5		
45	370 MD	7,553	30 years		2.19	R1		
46	370.1 DE	74,248	15 years	(3)	8.13	S2		
47	370.1 MD	45,856	10 years		14.64	S3		
48	371.1 MD	3,401	15 years		6.84	S3		
49	371.2 DE	30,075	18 years	(40)	8.2	R2		
50	371.2 MD	11,295	45 years	(50)	2.73	R3		
51	373 DE	80,431	38 years	(30)	0.95	R2		
52	373 MD	19,228	30 years	(30)	5.1	L0.5		
53	SUBTOTAL	3,316,379						
54	GENERAL							
55	390 DE	13,718	50 years	(10)	1.01	R3		
56	390 MD	50,244	35 years	(10)	3.43	S0		
57	391.1 DE	2,570	19 years		5.65	L2		
58	391.1 MD	1,937	15 years		5.78	SQ		
59	391.3 MD	2,974	10 years		10.14	SQ		
60	391.3 DE	14,231	5 years		21.49	SQ		
61	393 DE	234	40 years		19.74	R4		
62	394 DE	13,532	25 years		6.56	SQ		
63	394 MD	15,696	15 years		7.19	SQ		
64	395 DE		20 years		15.46	SQ		
65	397 MD	41,352	30 years	(10)	3.32	S2.5		
66	397 DE	73,188	25 years		4.13	L3		
67	397.1 MD	21,257	15 years		7.9	R2		
68	397.1 DE	26,487	15 years		6.98	S2		
69	397.3 MD	79,856	15 years		8.44	SQ		
70	397.3 DE	2,755	15 years		6.98	SQ		
71	398.1 DE	1,961	20 years		5.74	SQ		
72	398.1 MD	2,896	15 years		8.16	SQ		
73	392.2 DE	1,373	10 years		8.4	S2.5		
74	392.3 DE	984	14 years		6.33	S1.5		
75	392.4 DE	716	15 years		5.67	R2.5		

76	392.5 DE	378	8 years		10.86	S3	
77	392.8 DE	388	20 years		4.57	S0	
78	392.2 MD	193	10 years		8.34	S2.5	
79	392.3 MD	486	14 years		6.8	S1.5	
80	392.4 MD	177	15 years		6.1	R2.5	
81	392.5 MD	101	8 years		10.86	S3	
82	392.8 MD	148	20 years		4.57	R2.5	
83	SUBTOTAL	369,832					
84	COMMON						
85	390.3	79,734	75 years	(5)	0.8	S1.5	
86	390.3a	12,631	75 years	(5)	0.73	S1.5	
87	390.3b	857	40 years	(20)	(0.09)	R2	
88	391.1	7,300	20 years		5.38	SQ	
89	391.2	13,464	5 years		36.45	SQ	
90	393		25 years		6.27	SQ	
91	394	5,845	25 years		6.56	SQ	
92	397.1a	5,216	25 years		4.13	L3	
93	397.3	19.721	15 years		0.09	SQ	
94	398	13.708	20 years		5.22	SQ	
95	SUBTOTAL	158.476					
96	TOTAL	6,018,373					

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	Delaware											
2	General Regulation Legal		207,064	207,064		Electric	928	207,064				
3	2020 DE Rate Case 20-0149		4,012	4,012		Electric	928	4,012				
4	2022 DE Rate Case 22-0897		230,107	230,107		Electric	928	230,107				
5	DE Electric DSIC		1,598	1,598		Electric	928	1,598				
6	DE AFRR Filing		180,573	180,573		Electric	928	180,573				
7	Maryland											
8	2022 MD MYP 9681		188,750	188,750		Electric	928	(6,918)		928	195,667	
9	2021 MD Base Rate Case 9670		43,008	43,008		Electric	928			928	43,008	
10	General Regulation Legal		273,369	273,369		Electric	928	273,369				

11	Transmission:											
12	ER05-515 Annual Rate Updates - FERC Transmission		256,628	256,628		Electric	928	256,628				
13	ER21-205 Order No. 864 Compliance		400	400		Electric	928	400				
14	EL15-79 (TranSource) - FERC Transmission		647	647		Electric	928	647				
15	ER21-2965 - Transmission Wages and Salary (W&S) Allocator		8,369	8,369		Electric	928	8,369				
46	TOTAL		1,394,525	1,394,525				1,155,849			238,675	

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

   Electric R, D and D Performed Internally:

   Generation

   hydroelectric

   Recreation fish and wildlife
   Other hydroelectric

   Fossil-fuel steam
   Internal combustion or gas turbine
   Nuclear
   Unconventional generation
   Siting and heat rejection

   Transmission

   Overhead
   Underground

   Distribution
   Regional Transmission and Market Operation
   Environment (other than equipment)
   Other (Classify and include items in excess of $50,000.)
   Total Cost Incurred

   Electric, R, D and D Performed Externally:

   Research Support to the electrical Research Council or the Electric Power Research Institute
   Research Support to Edison Electric Institute
   Research Support to Nuclear Power Groups
   Research Support to Others (Classify)
   Total Cost Incurred
3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	A-6	Administrative and General R&D Costs	79,900		930.2	79,900	
2	B-1	Membership - EPRI		208,472	[a] Various	208,472	
3	B-4	Membership - NEETRAC (Georgia Tech Research Corp)		10,524	[b] Various	10,524	
4	B-4	Membership - Electric Drive Transportation Association		5,312	[c] Various	5,312	
5	B-4	Membership - Centre for Energy Advancement through Technical Innovation		18,022	[d] Various	18,022	
6	B-4	Membership - Watson & Renner		5,498	[e] Various	5,498	

7	B-4	Membership - Darcy Partners Power & Utilities		7,618	930.2	7,618	
8	B-5	Patent Legal Fees		1,754	930.2	1,754	
9	Total		79,900	257,200		337,100	

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Membership - EPRI:

FERC		Amount
588		135,507
566		72,965
Total	$	208,472

(b) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Membership - NEETRAC (Georgia Tech Research Corp):

FERC		Amount
588	$	5,367
566		5,157
Total	$	10,524

(c) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Membership - Electric Drive

FERC		Amount
588	$	2,656
566		2,656
Total	$	5,312

(d) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Membership - CEATI

FERC		Amount
588	$	4,686
566		13,336
Total	$	18,022

(e) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Membership - Watson & Renner

FERC		Amount
588	$	2,749
566		2,749
Total	$	5,498

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	32,710		
4	Transmission	1,135,074		
5	Regional Market			
6	Distribution	11,241,308		
7	Customer Accounts	2,356,307		
8	Customer Service and Informational	2,233,077		
9	Sales			
10	Administrative and General	2,807,070		

11	TOTAL Operation (Enter Total of lines 3 thru 10)	19,805,546		
12	Maintenance			
13	Production			
14	Transmission	2,439,300		
15	Regional Market			
16	Distribution	13,479,619		
17	Administrative and General	78,538		
18	TOTAL Maintenance (Total of lines 13 thru 17)	15,997,457		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	32,710		
21	Transmission (Enter Total of lines 4 and 14)	[a]3,574,374		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	24,720,927		
24	Customer Accounts (Transcribe from line 7)	2,356,307		
25	Customer Service and Informational (Transcribe from line 8)	2,233,077		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	[b]2,885,608		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	[c]35,803,003	2,052,581	37,855,584
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	510,862		
34	Storage, LNG Terminaling and Processing	844,870		
35	Transmission	983,603		
36	Distribution	6,520,147		
37	Customer Accounts	375,110		
38	Customer Service and Informational	127,546		
39	Sales			
40	Administrative and General	539,714		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	9,901,852		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	43,973		
47	Transmission	370,768		
48	Distribution	1,346,261		
49	Administrative and General	4,270		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	1,765,272		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	510,862		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	888,843		
56	Transmission (Lines 35 and 47)	1,354,371		

57	Distribution (Lines 36 and 48)	7,866,408		
58	Customer Accounts (Line 37)	375,110		
59	Customer Service and Informational (Line 38)	127,546		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	543,984		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	11,667,124	379,247	12,046,371
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	47,470,127	2,431,828	49,901,955
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	61,755,332	3,894,351	65,649,683
69	Gas Plant	10,267,273	397,424	10,664,697
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	72,022,605	4,291,775	76,314,380
72	Plant Removal (By Utility Departments)			
73	Electric Plant	5,652,828	425,464	6,078,292
74	Gas Plant	836,229	34,291	870,520
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	6,489,057	459,755	6,948,812
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Expenses from Merchandising, Jobbing & Contract Work - 416	1,866,135	85,183	1,951,318
80	Expenses of Non-Utility Operations - 417.1	13,990	791	14,781
81	Donations - 426.1	19,788	385	20,173
82	Exp. For Certain Civic, Political & Related Activities - 426.4	188,854	8,042	196,896
83	Other Deductions - 426.5	72,246	2,515	74,761
84	Plant Held for Future -105	2,066		2,066
85	Other Deferred Credits-253	2,154		2,154
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	2,165,233	96,916	2,262,149
96	TOTAL SALARIES AND WAGES	128,147,022	7,280,274	135,427,296

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: SalariesAndWagesElectricTransmission

Exelon Business Services Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 21 of this schedule total $4,392,053 for full-year 2024.

PHI Service Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 21 of this schedule total $648,411 for full-year 2024.

(b) Concept: SalariesAndWagesElectricAdministrativeAndGeneral

Exelon Business Services Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 27 of this schedule total $8,420,987 for full-year 2024.

PHI Service Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 27 of this schedule total $12,096,772 for full-year 2024.

(c) Concept: SalariesAndWagesElectricOperationAndMaintenance

Exelon Business Services Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 28 of this schedule total $14,678,471 for full-year 2024.

PHI Service Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 28 of this schedule total $31,996,691 for full-year 2024.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Common Utility Plant in Service

Acct	Beginning Bal	Additions	Retirements	Transfers/Adj	Ending Balances
301	$ 736,500	$ —	$ —	$ —	$ 736,500
303	73,016,616	6,271,021	—	—	79,287,637
389.1	1,621,110	—	—	—	1,621,110
390.3	71,936,070	19,466,025	(566,684)	3,510,930	94,346,341
391.1	5,389,121	1,919,212	—	—	7,308,333
391.3	16,098,176	3,609,466	(6,136,380)	—	13,571,262
393	—	—	—	—	—
394	5,221,555	627,818	(4,445)	—	5,844,928
397	25,662,200	213,078	(198,275)	—	25,677,003
398	11,479,311	1,492,538	—	—	12,971,849
Grand Total	**$ 211,160,659**	**$ 33,599,158**	**$ (6,905,784)**	**$ 3,510,930**	**$ 241,364,963**

Acct	Electric	Gas	Total Common Utility Plant
301	$ 606,066	$ 130,434	$ 736,500
303	65,245,796	14,041,841	$ 79,287,637
389.1	1,334,011	287,099	$ 1,621,110
390.3	77,637,604	16,708,737	$ 94,346,341
391.1	6,014,027	1,294,306	$ 7,308,333
391.3	11,167,792	2,403,470	$ 13,571,262
393	—	—	$ —
394	4,809,791	1,035,137	$ 5,844,928
397	21,129,606	4,547,397	$ 25,677,003
398	10,674,535	2,297,314	$ 12,971,849
	$ 198,619,228	**$ 42,745,735**	**$ 241,364,963**

E = 83.47%
G = 16.53%

Accumulated Provision for Depreciation of Common Utility Plant
DPL
12/31/2024

	Total Common	Electric	Gas
Balance at Beginning of Year	84,716,619	70,712,962	14,003,657
Depreciation Provision for the Year Charged to:			
403 Depreciation Expense	5,965,890	5,063,206	902,684
Net Charges for Plant Retired:			
Book Charges for Plant Retired	(6,905,783)	(5,682,769)	(1,223,014)
Cost of Removal, Net of Salvage	(373,405)	(307,275)	(66,130)
Other Debit or Credit Items:			
Transfers / Adjustments	222,437	183,043	39,394
Gain from Sale		—	—
Electric & Gas Allocator Adjustment	—	(1,153,531)	1,153,531
Balance at End of Year	83,625,758	68,815,636	14,810,122

Accumulated Provision for Amortization of Common Utility Plant
DPL
12/31/2024

	Total Common	Electric	Gas
Balance at Beginning of Year	51,251,759	42,779,843	8,471,916
Depreciation Provision for the			
Year Charged to:			
404 Amortization Expense	8,858,925	7,311,067	1,547,858
Net Charges for Plant Retired:			
Book Charges for Plant Retired	—	—	—
Cost of Removal, Net of Salvage	—	—	—
Other Debit or Credit Items			
Transfers / Adjustments	—	—	—
Electric & Gas Allocator Adjustment	—	(625,828)	625,828
Balance at End of Year	60,110,684	49,465,082	10,645,602

FERC FORM NO. 1 (ED. 12-87)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	280,805	601,742	832,685	1,464,994
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(2,889,766)	(5,513,922)	(7,231,528)	(10,294,106)
4	Transmission Rights	22,812,364	46,686,816	72,973,871	100,686,840
5	Ancillary Services	28,488	70,242	77,126	108,236
6	Other Items (list separately)				
7	Demand	8,712	22,988	27,892	29,186
46	TOTAL	20,240,603	41,867,866	66,680,046	91,995,150

FERC FORM NO. 1 (NEW. 12-05)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	7,294,105	MWH	16,653	5,770,028	MWH	1,469,994
			[(a)](#)				

2	Reactive Supply and Voltage		MWH	1,641			
3	Regulation and Frequency Response		[b] MWH	(349)			
4	Energy Imbalance						
5	Operating Reserve - Spinning		[c] MWH	319			
6	Operating Reserve - Supplement		[d] MWH	208			
7	Other		[e] MWH	[f]101,801			
8	Total (Lines 1 thru 7)	7,294,105	MWH	120,273	5,770,028	MWH	1,469,994

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

The number of units reported on Line #2, Column (b) is 7,294,105 MWH.

(b) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

The number of units reported on Line #2, Column (b) is 7,294,105 MWH.

(c) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

The number of units reported on Line #2, Column (b) is 7,294,105 MWH.

(d) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

The number of units reported on Line #2, Column (b) is 7,294,105 MWH.

(e) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

The number of units reported on Line #2, Column (b) is 7,294,105 MWH.

(f) Concept: AncillaryServicesPurchasedAmount

Other Ancillary Services Purchased are as follows:

Balancing Operating Reserve	$	101,743
Non-Synchronized Reserve		36
Reactive Services		22
	$	101,801

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	3,523	17	[a]8	2,661	862				
2	February	2,904	1	8	2,093	811				
3	March	2,792	1	7	2,033	759				
4	Total for Quarter 1				6,787	2,432	0	0	0	0
5	April	2,550	29	19	1,834	716				
6	May	2,760	25	18	2,062	698				
7	June	3,849	26	18	2,879	970				

8	Total for Quarter 2				6,775	2,384	0	0	0	0
9	July	4,130	16	18	3,132	998				
10	August	4,027	2	17	3,022	1,005				
11	September	3,016	1	18	2,253	763				
12	Total for Quarter 3				8,407	2,766	0	0	0	0
13	October	2,219	3	18	1,493	726				
14	November	2,616	30	21	1,963	653				
15	December	3,528	23	8	2,692	836				
16	Total for Quarter 4				6,148	2,215	0	0	0	0
17	Total				28,117	9,797	0	0	0	0

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: HourOfMonthlyPeakExcludingIsoAndRto

This note applies to rows 1, 2, 3, 5, 6, 7, 9, 10, 11, 13, 14, and 15. Amounts reported in Column (d) are presented in Eastern Standard Time (EST), as DPL operations are in that time zone.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0

17	Total Year to Date/Year				0	0	0	0	0	0

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2024-12-31	Year/Period of Report End of: 2024/ Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	11,895,564
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	826
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	350,067
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	12,601
7	Other		27	Total Energy Losses	805,075
8	Less Energy for Pumping		27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	0	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	13,064,133
10	Purchases (other than for Energy Storage)	7,294,105			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	5,770,028			
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	5,770,028			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	13,064,133			

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	1,223,368	35,523	3,523	17	[(a)]8
30	February	1,061,480	29,948	2,904	1	8
31	March	966,036	36,446	2,792	1	7
32	April	889,077	65,995	2,550	29	19

33	May	947,458	21,194	2,760	25	18
34	June	1,158,858	22,451	3,849	26	18
35	July	1,352,095	12,860	4,130	16	18
36	August	1,226,746	13,697	4,027	2	17
37	September	970,026	18,883	3,016	1	18
38	October	895,111	25,120	2,219	3	18
39	November	920,362	36,182	2,616	30	21
40	December	1,453,516	31,768	3,529	23	8
41	Total	13,064,133	350,067			

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: HourOfMonthlyPeak

This note applies to rows 29 - 40. Amounts reported in Column (f) are presented in Eastern Standard Time (EST), as DPL operations are in that time zone.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: 0
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	
3	Year Originally Constructed	
4	Year Last Unit was Installed	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	
6	Net Peak Demand on Plant - MW (60 minutes)	
7	Plant Hours Connected to Load	
8	Net Continuous Plant Capability (Megawatts)	
9	When Not Limited by Condenser Water	
10	When Limited by Condenser Water	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	Cost of Plant: Land and Land Rights	
14	Structures and Improvements	
15	Equipment Costs	

16	Asset Retirement Costs	
17	Total cost (total 13 thru 20)	
18	Cost per KW of Installed Capacity (line 17/5) Including	
19	Production Expenses: Oper, Supv, & Engr	
20	Fuel	
21	Coolants and Water (Nuclear Plants Only)	
22	Steam Expenses	
23	Steam From Other Sources	
24	Steam Transferred (Cr)	
25	Electric Expenses	
26	Misc Steam (or Nuclear) Power Expenses	
27	Rents	
28	Allowances	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Boiler (or reactor) Plant	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Steam (or Nuclear) Plant	
34	Total Production Expenses	0
35	Expenses per Net kWh	

35	**Plant Name**
36	Fuel Kind
37	Fuel Unit
38	Quantity (Units) of Fuel Burned
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year
41	Average Cost of Fuel per Unit Burned
42	Average Cost of Fuel Burned per Million BTU
43	Average Cost of Fuel Burned per kWh Net Gen
44	Average BTU per kWh Net Generation

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0
1	Kind of Plant (Run-of-River or Storage)	
2	Plant Construction type (Conventional or Outdoor)	
3	Year Originally Constructed	

4	Year Last Unit was Installed	
5	Total installed cap (Gen name plate Rating in MW)	
6	Net Peak Demand on Plant-Megawatts (60 minutes)	
7	Plant Hours Connect to Load	
8	**Net Plant Capability (in megawatts)**	
9	(a) Under Most Favorable Oper Conditions	
10	(b) Under the Most Adverse Oper Conditions	
11	Average Number of Employees	
12	Net Generation, Exclusive of Plant Use - kWh	
13	**Cost of Plant**	
14	Land and Land Rights	
15	Structures and Improvements	
16	Reservoirs, Dams, and Waterways	
17	Equipment Costs	
18	Roads, Railroads, and Bridges	
19	Asset Retirement Costs	
20	Total cost (total 13 thru 20)	
21	Cost per KW of Installed Capacity (line 20 / 5)	
22	**Production Expenses**	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Hydraulic Expenses	
26	Electric Expenses	
27	Misc Hydraulic Power Generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Hydraulic Plant	
34	Total Production Expenses (total 23 thru 33)	
35	Expenses per net kWh	

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0

1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0
6	Plant Hours Connect to Load While Generating	0
7	Net Plant Capability (in megawatts)	0
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - kWh	0
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	0
12	**Cost of Plant**	
13	Land and Land Rights	
14	Structures and Improvements	0
15	Reservoirs, Dams, and Waterways	0
16	Water Wheels, Turbines, and Generators	0
17	Accessory Electric Equipment	0
18	Miscellaneous Powerplant Equipment	0
19	Roads, Railroads, and Bridges	0
20	Asset Retirement Costs	0
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	**Production Expenses**	
24	Operation Supervision and Engineering	0
25	Water for Power	0
26	Pumped Storage Expenses	0
27	Electric Expenses	0
28	Misc Pumped Storage Power generation Expenses	0
29	Rents	0
30	Maintenance Supervision and Engineering	0
31	Maintenance of Structures	0
32	Maintenance of Reservoirs, Dams, and Waterways	0
33	Maintenance of Electric Plant	0
34	Maintenance of Misc Pumped Storage Plant	0
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per kWh (line 37 / 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).

2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1													
2													
3													
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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Account for Project Costs (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1																			
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3																			
4																			
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32																			
33																			
34																			
35	TOTAL			0	0	0	0	0	0	0	0	0	0	0	0		0	0	0

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
2. In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR				
					Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1									
2									
3									
4									
5									
6									
7									
8									
9									
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28									
29									
30									
31									
32									
33									
34									
35									
36	TOTAL			0	0	0	0	0	0

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)			LENGTH (Pole miles) - (In the case of underground lines report circuit miles)				COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated	Type of Supporting Structure	On Structure of Line Designated	On Structures of Another Line	Number of Circuits	Size of Conductor and Material	Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	500 KV Line (wholly owned)		500	500	SC Steel	15.55		3		842,230	26,912,016	27,754,246				
2	230 KV Lines		230	230	Various	387.52	83.64	27		15,386,161	246,414,477	261,800,638				
3	138 KV Lines		138	138	Various	504.09	90.01	86		11,248,373	556,598,202	567,846,575				
4	69kV Lines		69	69	Various	568.65	13.02	74		7,548,675	370,201,254	377,749,929				
5	Underground Lines	5.38 mi /138, 2.09 mi/69				7.47		10		9,713	67,952,292	67,962,005				
6	SEE DETAIL ON	FOLLOWING PAGES														

7	JOINT VENTURES															
8	EHV System		500	500	Steel Tower	127.00		1		184,167	1,752,004	1,936,171				
9	LDV System		500	500	Stl/Alm Tower	154.00		6		181,238	952,788	1,134,026				
10	SE System		500	500	Steel Tower											
11	(15)-(17) Above															
12	Non-Specific Line charges															
13	(ALL KV Inclusive)															
14	Line Expenses												9,027,227	3,962,115	[a]227,196	13,216,538
15	Keeney	Steele	230	230	Steel towers		57.20	1	1590 ACSR							
16	Indian River	Piney Grove	230	230	Wood H-frame	25.83		1	1590 ACSR							
17	Red Lion	Silver Run	230	230	Steel poles	11.89		1	1590 ACSR							
18	Silver Run	Cedar Creek	230	230	Steel poles	9.08		1	1590 ACSR							
19	Cedar Creek	Milford	230	230	Wood H-frame	42.84		1	1590 ACSR							
20	Red Lion	Silver Run	230	230	Steel poles	7.58	4.31	1	1590 ACSR							
21	Silver Run	Cartanza	230	230	Steel poles	25.83		1	1590 ACSR							
22	Cartanza	Milford	230	230	Steel poles	26.50		1	1590 ACSR							
23	Milford	Indian River	230	230	Steel poles	26.37		1	1590 ACSR							
24	Milford	Cool Spring	230	230	Wood H-frame	14.95		1	1590 ACSR							
25	Indian River	Cool Spring	230	230	Steel poles	[a]11.54		1	1590 ACSR							
26	Milford	Steele	230	230	Wood H-frame	23.39		1	1590 ACSR							
27	Colora	Nottingham (Bradford)	230	230	Steel towers	1.76		1	795 ACSR							
28	Colora	Crest	230	230	Steel poles	7.57		1	1590 ACSR							
29	Claymont Sub	Linwood	230	230	Steel poles	0.99		1	1590 ACSR							
30	Edge Moor	Linwood	230	230	Steel poles		8.10	1	1590 ACSR							
31	Colora	Conowingo	230	230	Steel poles	1.92		1	795 ACSR							
32	Crest	Cecil	230	230	Steel poles	8.45		1	1590 ACSR							
33	Keeney	Steele	230	230	Steel towers	57.07		1	1590 ACSR							
34	#1 Keeney	Harmony	230	230	Steel poles	6.14		1	1590 ACSR							
35	Keeney	Red Lion	230	230	Steel towers	8.05		1	1590 ACSR							
36	Harmony	Edge Moor	230	230	Steel poles	11.87		1	1590 ACSR							
37	#2 Keeney	Harmony	230	230	Steel poles	9.30	0.20	1	1590 ACSR							
38	Edge Moor	Claymont	230	230	Steel poles	7.07		1	1590 ACSR							
39	Hay Road	Red Lion	230	230	Steel poles	10.72	13.83	1	1590 ACSR							
40	Cartanza	Garrison	230	230	Steel poles	2.63		1	1590 ACSR							

41	Steele	Vienna	230	230	Wood H-frame	28.17		1	1590 ACSR							
42	Church	Steele	138	138	Wood H-frame	25.69		1	1590 ACSR							
43	Milford	Milford City	138	138	Wood poles	0.24		1	336.4 ACSR							
44	Nelson	Indian River	138	138	Wood H-frame	21.41		1	477 ACSR							
45	Cheswold	Felton	138	138	Wood poles	14.38		1	954 ACSR							
46	Indian River	Robinsonville	138	138	Wood poles	11.74		1	954 ACSR							
47	Robinsonville	Rehoboth	138	138	Steel poles	6.90		1	954 ACSR							
48	Vienna	Nelson	138	138	Steel Poles	13.68		1	1590 ASCR							
49	Felton	South Harrington	138	138	Wood poles	8.49		1	954 ACSR							
50	Vienna	Vienna (AT20)	138	138	Wood poles	0.17		1	1590 ACSR							
51	Easton	Steele	138	138	Steel poles	23.62		1	996.2 ACSR							
52	Loretto	Kings Creek	138	138	Wood H-frame	7.18		1	954 ACSR			0.00				
53	Kings Creek	Pocomoke	138	138	Wood H-frame	9.14		1	954 ACSR							
54	Indian River	Bishop	138	138	Steel poles	12.33		1	1590 ACSR			0.00				
55	Indian River	Bishop	138	138	Steel poles	7.24	5.18	1	1590 ACSR							
56	Oak Hall	Eastern Shore Solar	138	138	Steel poles	0.07		1	954 ACSR			0.00				
57	Church	Carville	138	138	Steel poles	0.13	17.58	1	1590 ACSR							
58	Kings Creek	Great Bay Solar	138	138	Steel poles	0.10		1	954 ACSR							
59	Ocean Bay	138th Street	138	138	Wood poles	2.97		1	966.2 ACSR							
60	138th Street	Bethany	138	138	Steel poles	6.13		1	954 ACSR							
61	Roxana	Bethany	138	138	Wood H-frame	3.65		1	954 ACSR							
62	Indian River	Roxana	138	138	Wood H-frame	8.54		1	954 ACSS & 954 ACSR							
63	Indian River AT20	Indian River 138	138	138	Steel poles	0.26		1	1590 ACSR							
64	Indian River AT22	Indian River 138	138	138	Steel poles	[(b)]0.29		1	[(f)] 2000 KCMIL CU							
65	Steele	Hillsboro	138	138	Wood H-frame	7.24		1	954 ACSR							
66	New Church	Oak Hall	138	138	Wood poles	3.68		1	[(g)] 954 ACSR							
67	Piney Grove	New Church	138	138	Wood H-frame	21.80		1	477 ACSR							
68	New Church	Oak Hall	138	138	Wood H-frame	3.56		1	556.5 ACSS							
69	Indian River	Conaway	138	138	Wood H-frame	[(c)]8.50		1	954 ACSR							
70	Conaway	North Seaford	138	138	Wood H-frame	16.94		1	954 ACSR							
71	Clayton	Cheswold	138	138	Wood poles	6.63		1	954 ACSR							
72	North Seaford	South Harrington	138	138	Wood poles	16.22		1	954 ACSR							
73	Clayton	Demec	138	138	Steel poles	0.69		1	954 ACSR							
74	Farmview	Milford	138	138	Wood poles	2.44		1	954 ACSR							

75	Farmview	South Harrington	138	138	Wood poles	7.73		1	954 ACSR							
76	Piney Grove	Loretto	138	138	Wood H-frame	9.49		1	477 ACSR							
77	Bishop	Worcester	138	138	Wood H-frame	5.33		1	954 ACSR							
78	Loretto	Vienna	138	138	Wood H-frame	19.44		1	1590 ACSR							
79	Bishop	St Martins Neck Ocean Bay	138	138	Wood H-frame	(d)9.97		1	(h) 954 ACSR							
80	Pocomoke	Oak Hall	138	138	Wood H-frame	8.57		1	954 ACSR							
81	Hillsboro	Wye Mills	138	138	Wood H-frame	8.59		1	954 ACSR							
82	Wattsville	Oak Hall	138	138	Steel poles	3.91		1	954 ACSR							
83	#1 Glasgow	Mt Pleasant	138	138	Steel poles	10.99		1	1590 ACSR							
84	Red Lion West	Reybold	138	138	Steel poles	1.11		1	954 ACSR							
85	New Castle	Town of New Castle	138	138	Steel poles	0.40		1	954 ACSR							
86	Edge Moor	Brandywine	138	138	Steel poles	2.52		1	954 ACSR							
87	Edge Moor	Christiana	138	138	Steel towers	2.56	0.15	1	954 ACSR							
88	Keeney	Churchmans	138	138	Steel poles	6.05		1	1590 ACSR							
89	Churchmans	Basin Road	138	138	Steel poles	0.93	2.50	1	636 ACSR							
90	Mt Pleasant	Towsend	138	138	Steel poles	11.27		1	1590 ACSR							
91	Keeney	Glasgow	138	138	Steel poles	3.33		1	636 ACSR							
92	New Castle	Hare's Corner	138	138	Steel poles	3.68		1	954 Phoenix							
93	Hare's Corner	Red Lion	138	138	Steel poles	4.48	0.68	1	954 Rail							
94	Christiana	New Castle	138	138	Steel towers	0.75	3.46	1	636 ACSR							
95	Basin Road	Bear	138	138	Wood poles	4.69		1	954 ACSR							
96	Keeney	Sunset Lake	138	138	Wood poles	2.27		1	954 ACSR							
97	Red Lion	Reybold	138	138	Steel poles	0.14	1.11	1	954 ACSR							
98	Glasgow	Cecil	138	138	Steel poles	5.24		1	(i) 1590 ACSR & 768.2 ACSS							
99	Basin Road	Kiamensi	138	138	Steel towers	3.20		1	954 ACSR							
100	Basin Road	New Castle	138	138	Steel towers	0.11	2.94	1	954 ACSR							
101	Keeney	Chapel Street	138	138	Steel poles	1.27	2.82	1	954 ACSR							
102	Harmony	Chapel Street	138	138	Steel poles	3.32		1	336 ACSR							
103	Keeney EHV	Keeney 138	138	138	Steel poles	0.25		1	1590 ACSR							
104	Carrcroft	Talleyville	138	138	Wood poles	3.56		1	477 AA							
105	Edge Moor	Carrcroft	138	138	Steel towers	0.84	2.81	1	954 ACSR							
106	Motiva	Reybold	138	138	Wood poles	0.08		1	954 ACSR							
107	Carrcroft	West Wilmington	138	138	Steel towers	4.33		1	954 ACSR							
108	West Wilmington	Silverbrook	138	138	Steel poles	1.97		1	954 ACSR							
109	Harmony	Kiamensi	138	138	Steel poles	4.23		1	1590 ACSR							
110	Kiamensi	Silverbrook	138	138	Steel towers	2.70	1.00	1	954 ACSR							
111	Brandywine	Carrcroft	138	138	Steel towers	(e)1.36	2.87	1	(j) 954 ACSR							
112	Red Lion	Bloom Energy	138	138	Steel poles	0.44		1	954 ACSR							
113	Cedar Creek	Clayton	138	138	Wood poles	9.23		1	954 ACSR							

114	Towsend	Church	138	138	Steel poles	12.32		1	636 ACSR							
115	Kiamensi	Milltown	138	138	Wood poles	1.40	1.31	1	954 ACSR							
116	Milltown	Mermaid-Valley Road	138	138	Wood poles	4.60		1	954 ACSR							
117	Valley Road	Hockessin	138	138	Wood poles	1.78		1	954 ACSR							
118	Kiamensi	Hockessin	138	138	Wood poles	6.26		1	954 ACSR							
119	Reybold	Lums Pond	138	138	Wood poles	8.22		1	954 ACSR							
120	Lums Pond	Mt Pleasant	138	138	Wood poles	9.74		1	954 ACSR							
121	Bear	Sunset Lake	138	138	Wood poles	5.31		1	954 ACSR							
122	#2 Glasgow	Mt Pleasant	138	138	Steel poles	11.10		1	1590 ACSR							
123	Carville	Wye Mills	138	138	Steel poles	0.12	7.93	1	1590 ACSR							
124	Piney Grove	Wattsville	138	138	Steel poles	0.71	30.19	1	1590 ACSR							
125	Church	Pondtown	138	138	Steel poles	0.13	7.48	1	1590 ACSR							
126	Motiva	Praxair	138	138	No Poles	0.02		1	1590 ACSR							
127	Soladigo Solar	Townsend	138	138	No Poles	0.03		1	795 ACSR							
128	Richfield Solar	Todd	69	69	No poles	0.17		1	954 ACSR							
36	TOTAL					[l]2,656.08	[m]360.32	[n]321		35,400,557.00	1,270,783,033.00	1,306,183,590.00	9,027,227.11	3,962,115.14	227,195.85	13,216,538.10

FERC FORM NO. 1 (ED. 12-87)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: LengthForStandAloneTransmissionLines

Includes 0.54 miles of steel poles as well.

(b) Concept: LengthForStandAloneTransmissionLines

Includes 0.14 miles of UG as well.

(c) Concept: LengthForStandAloneTransmissionLines

Includes 954 ACSR as well.

(d) Concept: LengthForStandAloneTransmissionLines

Includes 2.76 miles of UG as well.

(e) Concept: LengthForStandAloneTransmissionLines

Includes 1.23 miles of UG as well.

(f) Concept: SizeOfConductorAndMaterial

Includes 1949 ACSS as well.

(g) Concept: SizeOfConductorAndMaterial

Includes 1949 ACSS as well.

(h) Concept: SizeOfConductorAndMaterial

Includes KCMIL AL as well.

(i) Concept: SizeOfConductorAndMaterial

Includes 768.2 ACSS as well.

(j) Concept: SizeOfConductorAndMaterial

Includes KCMIL AL as well.

(k) Concept: RentExpensesOfTransmissionLine

TRANSMISSION LINE AGREEMENTS:

Cost of lines and related operating expenses as shown are respondent's share only and are to the appropriate regulatory accounts as prescribes by the Uniform System of Accounts.

1. Owners in common of the "Salem-New Freedom (South)", "Hope Creek-Red Lion Line (NJ Section)", "Deans-Branchburg", the section of "Salem-Deans" north of "New Freedom", and "Hope Creek-Salem" LDV Transmission Lines are as follows:

	Percentage
Public Service Electric & Gas	42.55

Atlantic City Electric	13.90
Delmarva Power & Light	1.00
PECO Energy Co	42.55
Total	100.00

2. Owners in common of the reconstructed river crossing portion of the Hope Creek-Red Lion line are as follows:

	Percentage
Public Service Electric & Gas	42.55
Atlantic City Electric	7.45
Delmarva Power & Light	7.45
PECO Energy Co	42.55
Total	100.00

LDV (500KV) Summary:
Delmarva holds a 7.45% share in the Lower DE Valley (LDV) Transmission Project. (Its over investment results in net rental income).

(l) Concept: LengthForStandAloneTransmissionLines

Totals for FERC Page 422-423 Columns F "On structure of Line Designated (F)", Column G "On structures of another Line (G)", and Column H "Number of Circuits (H)" displayed in Row 36 have double counted the values for row 2 230 KV line and row 3 138 KV line as the detail for these lines is broken out below the summary page. Corrected balances should exclude the totals presented on the summary for 230 KV and 138 KV and adjusted balances should be as follows (F) 1764, (G) 187, Column (H) 204.

(m) Concept: LengthForTransmissionLinesAggregatedWithOtherStructures

Totals for FERC Page 422-423 Columns F "On structure of Line Designated (F)", Column G "On structures of another Line (G)", and Column H "Number of Circuits (H)" displayed in Row 36 have double counted the values for row 2 230 KV line and row 3 138 KV line as the detail for these lines is broken out below the summary page. Corrected balances should exclude the totals presented on the summary for 230 KV and 138 KV and adjusted balances should be as follows (F) 1764, (G) 187, Column (H) 204.

(n) Concept: NumberOfTransmissionCircuits

Totals for FERC Page 422-423 Columns F "On structure of Line Designated (F)", Column G "On structures of another Line (G)", and Column H "Number of Circuits (H)" displayed in Row 36 have double counted the values for row 2 230 KV line and row 3 138 KV line as the detail for these lines is broken out below the summary page. Corrected balances should exclude the totals presented on the summary for 230 KV and 138 KV and adjusted balances should be as follows (F) 1764, (G) 187, Column (H) 204.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)	Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	(q)
1	SOLADIGO SOLAR	TOWNSEND	0.07					795 ACSR			138						
2	TODD	MITCHELL SOLAR	0.02					954 ACSR			69						
44	TOTAL		0.09		0	0	0										

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment		
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)				Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)

1	Andora - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
2	Appleton - Cecil, MD	Distribution	Unattended	35	4	0	7	2	0	0	0	0
3	Basin Road - New Castle, DE 1	Transmission	Unattended	138	69	0	84	1	0	0	0	0
4	Basin Road - New Castle, DE 2	Distribution	Unattended	69	12	0	38	1	0	0	0	0
5	Basin Road - New Castle, DE 3	Distribution	Unattended	138	12	0	38	1	0	69kV Capacitor Bank	1	24
6	Beaglin - Salisbury, MD	Distribution	Unattended	69	25	0	112	2	0	0	0	0
7	Bear - New Castle, DE 1	Distribution	Unattended	138	12	0	112	2	0	0	0	0
8	Bear - New Castle, DE 2	Distribution	Unattended	138	35	0	84	1	0	0	0	0
9	Bethany - Bethany, DE 1	Distribution	Unattended	138	12	0	40	1	0	0	0	0
10	Bethany - Bethany, DE 2	Transmission	Unattended	138	69	0	224	1	0	138kV Capacitor Bank	2	29
11	Bethany - Bethany, DE 3	Distribution	Unattended	69	12	0	22	1	0	69kV Capacitor Bank	2	34
12	Blue Ball Road - Elkton, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
13	Bohemia - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
14	Bozman - Bozman, MD	Distribution	Unattended	69	25	0	28	1	0	0	0	0
15	Brandywine - Wilmington, DE	Distribution	Unattended	138	12	0	168	2	0	12kV Capacitor Bank	2	14
16	Bridgeville - Bridgeville, DE	Distribution	Unattended	69	12	0	37	2	0	69kV Capacitor Bank	2	30
17	Brookside - Pencader, DE	Distribution	Unattended	35	12	0	45	2	0	0	0	0
18	Calvert - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
19	Cambridge - Cambridge, MD	Distribution	Unattended	69	12	0	68	2	0	69kV Capacitor Bank	1	12
20	Carrcroft - Brandywine, DE 1	Transmission	Unattended	138	69	0	112	1	0	138kV Capacitor Bank	2	24
21	Carrcroft - Brandywine, DE 2	Distribution	Unattended	138	35	0	84	1	0	34kV Capacitor Bank	2	29
22	Cathers - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
23	Cayots - Cecil, MD	Distribution	Unattended	35	4	0	5	2	0	0	0	0
24	Cecil - Cecil, MD 1	Distribution	Unattended	138	35	0	112	1	0	0	0	0
25	Cecil - Cecil, MD 2	Distribution	Unattended	230	35	0	90	1	0	0	0	0
26	Cecil - Cecil, MD 3	Transmission	Unattended	230	138	0	336	1	0	0	0	0
27	Cecil - Cecil, MD 4	Distribution	Unattended	35	4	0	8	2	0	0	0	0
28	Cedar Creek - New Castle, DE 1	Transmission	Unattended	230	138	0	336	1	0	230kV Reactor	1	40
29	Cedar Creek - New Castle, DE 2	Distribution	Unattended	138	25	0	28	1	0	0	0	0
30	Cedar Neck - Cedar Neck, DE 3	Distribution	Unattended	69	12	0	75	2	0	69kV Capacitor Bank	2	24
31	Centreville - Centreville, MD	Distribution	Unattended	69	12	0	33	2	0	0	0	0
32	Chapel St - Newark, DE	Distribution	Unattended	138	35	0	84	1	0	138kV Capacitor Bank	2	29
33	Charles - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
34	Chesapeake City - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
35	Chestertown - Chestertown, MD	Distribution	Unattended	69	25	0	112	2	0	69kV Capacitor Bank	1	8

36	Chestnut Run - Christiana, DE	Distribution	Unattended	35	12	0	42	2	0	12kV Capacitor Bank	2	6
37	Cheswold - Cheswold, DE 1	Distribution	Unattended	138	25	0	28	1	0	138kV Capacitor Bank	2	19
38	Cheswold - Cheswold, DE 2	Transmission	Unattended	138	69	0	225	1	0	0	0	0
39	Christiana - Wilmington, DE	Distribution	Unattended	138	12	0	168	3	0	12kV Capacitor Bank	6	36
40	Church - Millington, MD 1	Transmission	Unattended	138	69	0	337	2	0	138kV Capacitor Bank	2	22
41	Church - Millington, MD 2	Distribution	Unattended	69	25	0	38	2	0	0	0	0
42	Churchmans - New Castle, DE	Distribution	Unattended	138	12	0	106	2	0	0	0	0
43	Claymont - Brandywine, DE	Transmission	Unattended	230	69	0	336	2	0	0	0	0
44	Clayton - Clayton, DE 1	Distribution	Unattended	25	4	0	4	1	0	0	0	0
45	Clayton - Clayton, DE 2	Distribution	Unattended	138	25	0	56	2	0	0	0	0
46	Colora - Cecil, MD	Distribution	Unattended	230	35	0	220	2	0	0	0	0
47	Cool Spring - Milton, DE	Transmission	Unattended	230	69	0	336	1	0	0	0	0
48	Cowlane - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
49	Crest, Cecil Co., MD	Distribution	Unattended	230	35	0	224	2	0	0	0	0
50	Crisfield - Crisfield, MD 1	Distribution	Unattended	69	25	0	28	1	0	0	0	0
51	Crisfield - Crisfield, MD 2	Distribution	Unattended	69	12	0	14	1	0	0	0	0
52	Crothers Road, Cecil Co., MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
53	Culver - Ocean City, MD	Distribution	Unattended	69	25	0	22	1	0	0	0	0
54	Darley - Brandwine, DE 1	Distribution	Unattended	69	12	0	71	2	0	0	0	0
55	Darley - Brandwine, DE 2	Distribution	Unattended	69	35	0	50	1	0	0	0	0
56	Darlington - Harford, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
57	Delaware City- Delaware City, DE	Distribution	Unattended	69	14	0	212	2	0	0	0	0
58	Dublin - Harford, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
59	Dupont Experimental- Wilmington, DE	Distribution	Unattended	35	12	0	60	3	0	0	0	0
60	E New Market - East New Market, MD	Distribution	Unattended	69	12	0	34	2	0	0	0	0
61	Easton - Easton, MD	Transmission	Unattended	138	69	0	168	1	0	0	0	0
62	Edgemoor - Brandywine, DE 1	Distribution	Unattended	138	12	0	62	1	0	0	0	0
63	Edgemoor - Brandywine, DE 2	Transmission	Unattended	138	69	0	212	2	0	0	0	0
64	Edgemoor - Brandywine, DE 3	Transmission	Unattended	230	138	0	336	1	0	0	0	0
65	Edgemoor - Brandywine, DE 4	Distribution	Unattended	69	12	0	206	3	0	0	0	0
66	Elkneck - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
67	Elkton - Cecil, MD	Distribution	Unattended	35	4	0	19	4	0	0	0	0
68	Faulk Road - Brandywine, DE	Distribution	Unattended	35	12	0	42	2	0	0	0	0
69	Felton - Felton, DE	Distribution	Unattended	138	25	0	28	1	0	138kV Capacitor Bank	2	34
70	Five Points - Five Points, DE	Distribution	Unattended	69	12	0	45	2	0	0	0	0
71	Foundry - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
72	Frankford - Frankford, DE	Distribution	Unattended	138	25	0	25	1	0	0	0	0
73	Fruitland - Fruitland, MD	Distribution	Unattended	69	25	0	103	2	0	0	0	0
74	Gallion - Harford, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
75	Gilpin - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
76	Glasgow - New Castle, DE 1	Distribution	Unattended	138	12	0	28	1	0	0	0	0
77	Glasgow - New Castle, DE 2	Distribution	Unattended	138	35	0	84	1	0	0	0	0

78	Glen - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
79	Grace Street - St. Michaels, MD	Distribution	Unattended	69	12	0	32	2	0	0	0	0
80	Grasonville - Grasonville, MD	Distribution	Unattended	69	25	0	56	2	0	0	0	0
81	Greenbank - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
82	Hances - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
83	Harbeson - Harbeson, DE	Distribution	Unattended	69	25	0	38	2	0	0	0	0
84	Hares Corner - New Castle, DE	Distribution	Unattended	138	12	0	93	2	0	0	0	0
85	Harford - Harford, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
86	Harmony - White Clay, DE 1	Transmission	Unattended	230	138	0	896	2	0	0	0	0
87	Harmony - White Clay, DE 2	Distribution	Unattended	138	35	0	134	2	0	138kV Capacitor Bank	2	22
88	Harmony - White Clay, DE 3	Distribution	Unattended	138	12	0	106	2	0	0	0	0
89	Harrington - Harrington, DE	Distribution	Unattended	69	25	0	56	2	0	0	0	0
90	Harris - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
91	Hebron - Hebron, MD	Distribution	Unattended	69	25	0	56	2	0	0	0	0
92	Hillsboro - Hillsboro, MD	Distribution	Unattended	138	25	0	56	2	0	0	0	0
93	Hockessin - Mill Creek, DE	Distribution	Unattended	138	12	0	112	2	0	0	0	0
94	Indian River - Millsboro, DE 1	Transmission	Unattended	230	138	0	1344	3	0	230kV SVC and 230kV Capacitor Bank	2	200
95	Indian River - Millsboro, DE 2	Distribution	Unattended	230	15	0	150	1	0	0	0	0
96	Indian River - Millsboro, DE 3	Transmission	Unattended	138	69	0	225	1	0	0	0	0
97	Irishtown - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
98	Jacktown - Cambridge, MD	Distribution	Unattended	69	12	0	11	1	0	0	0	0
99	Keeney EHV - Pencader Hd, DE 1	Transmission	Unattended	500	230	0	2000	2	0	0	0	0
100	Keeney EHV - Pencader Hd, DE 2	Transmission	Unattended	230	138	0	448	1	0	0	0	0
101	Keeney EHV - Pencader Hd, DE 3	Distribution	Unattended	230	35	0	84	1	0	0	0	0
102	Keeney 138kV - Pencader Hd, DE	Distribution	Unattended	138	12	0	37	1	0	138kV Capacitor Bank	1	36
103	Kenney - Snow Hill, MD 1	Distribution	Unattended	69	25	0	13	1	0	0	0	0
104	Kenney- Snow Hill, MD 2	Distribution	Unattended	69	12	0	13	1	0	0	0	0
105	Kent - Dover, DE	Distribution	Unattended	69	25	0	47	2	0	0	0	0
106	Kiamensi - Christiana Rd, DE 1	Transmission	Unattended	138	69	0	112	1	0	138kV Capacitor Bank	1	32
107	Kiamensi - Christiana Rd, DE 2	Distribution	Unattended	138	35	0	106	2	0	0	0	0
108	Kilby - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
109	Kings Creek - Princess Anne, MD 1	Transmission	Unattended	138	69	0	224	2	0	0	0	0
110	Kings Creek - Princess Anne, MD 2	Distribution	Unattended	138	25	0	56	2	0	0	0	0
111	Laurel - Laurel, DE	Distribution	Unattended	69	12	0	60	2	0	69kV Capacitor Bank	1	20
112	Leslie - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
113	Liberty Grove - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
114	Little Falls - Little Falls, DE	Distribution	Unattended	35	12	0	20	1	0	0	0	0
115	Loretto - Princess Anne, MD	Transmission	Unattended	138	69	0	106	2	0	0	0	0
116	Lums Pond - New Castle, DE	Distribution	Unattended	138	25	0	93	2	0	0	0	0
117	Lynch - Lynch, MD	Distribution	Unattended	69	25	0	28	1	0	0	0	0
118	Macton - Harford, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0

119	Maridel - Ocean City, MD	Distribution	Unattended	69	12	0	45	2	0	0	0	0
120	Massey - Galena, MD	Distribution	Unattended	69	25	0	28	1	0	69kV Capacitor Bank	1	8
121	Mechanics - Cecil, MD	Distribution	Unattended	35	4	0	3	1	0	0	0	0
122	Mermaid - New Castle, DE 1	Distribution	Unattended	35	12	0	20	1	0	0	0	0
123	Mermaid - New Castle, DE 2	Distribution	Unattended	138	12	0	56	1	0	0	0	0
124	Middle - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
125	Midway - Rehoboth, DE	Distribution	Unattended	69	12	0	60	2	0	0	0	0
126	Milford - Milford, DE 1	Distribution	Unattended	138	25	0	56	1	0	0	0	0
127	Milford - Milford, DE 2	Transmission	Unattended	230	138	0	336	1	0	0	0	0
128	Milford Crossroads - Mill Cr Rd, DE	Distribution	Unattended	35	12	0	45	2	0	0	0	0
129	Millsboro - Millsboro, DE	Distribution	Unattended	69	25	0	94	2	0	0	0	0
130	Milltown - Mill Cr Rd, DE	Distribution	Unattended	138	12	0	112	2	0	0	0	0
131	Montchanin -Wilmington, DE	Distribution	Unattended	35	12	0	45	2	0	0	0	0
132	Mt. Hermon - Salisbury, MD	Distribution	Unattended	69	25	0	94	2	0	0	0	0
133	Mount Pleasant - New Castle, DE	Distribution	Unattended	138	25	0	79	2	0	138kV Capacitor Bank	2	7
134	Naamans - Brandywine, DE	Distribution	Unattended	69	12	0	75	2	0	0	0	0
135	Nelson - Delmar, DE 1	Transmission	Unattended	138	69	0	112	1	0	138kV SVC	1	150
136	Nelson - Delmar, DE 2	Distribution	Unattended	138	12	0	50	2	0	0	0	0
137	Nesbitt - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	12kV Capacitor Bank	2	12
138	New Castle, DE 1	Distribution	Unattended	69	12	0	123	3	0	0	0	0
139	New Castle, DE 2	Transmission	Unattended	138	138	0	0	0	0	138kV Reactor	1	60
140	Normira - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
141	North East - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
142	N Salisbury - Salisbury, MD	Distribution	Unattended	69	25	0	93	2	0	0	0	0
143	N Seaford - Seaford, DE 1	Transmission	Unattended	138	69	0	187	2	0	69kV Capacitor Bank	1	10
144	N Seaford - Seaford, DE 2	Distribution	Unattended	69	12	0	47	2	0	0	0	0
145	Oak Hall - Oak Hall, VA	Transmission	Unattended	138	69	0	224	2	0	0	0	0
146	Ocean Bay - Ocean City, MD 1	Distribution	Unattended	138	12	0	84	2	0	0	0	0
147	Ocean Bay - Ocean City, MD 2	Transmission	Unattended	138	69	0	224	1	0	0	0	0
148	Ocean City - Ocean City, MD 3	Distribution	Unattended	69	12	0	75	2	0	0	0	0
149	138th St - Ocean City, MD	Distribution	Unattended	138	12	0	84	2	0	138kV SVC	1	70
150	Otsego - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
151	Pemberton - Salisbury, MD	Distribution	Unattended	69	25	0	37	1	0	0	0	0
152	Perch - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
153	Piney Grove - Salisbury, MD 1	Transmission	Unattended	138	69	0	225	1	0	0	0	0
154	Piney Grove - Salisbury, MD 2	Transmission	Unattended	230	138	0	336	1	0	0	0	0
155	Pocomoke - Pocomoke, MD	Distribution	Unattended	138	12	0	45	2	0	0	0	0
156	Point Breeze - Brandywine, DE	Distribution	Unattended	35	12	0	42	2	0	0	0	0
157	Porter's Bridge - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
158	Preston-Preston	Distribution	Unattended	69	12	0	7	1	0	0	0	0
159	Price Sub - Price, MD	Distribution	Unattended	69	25	0	28	1	0	0	0	0
160	Prince-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0

161	Queenstown - Queenstown, MD	Transmission	Unattended	69	69	0	0	0	0	69kV Capacitor Bank	2	31
162	Railroad -Elkton, MD	Distribution	Unattended	35	4	0	6	1	0	0	0	0
163	Red Lion-New Castle, DE 1	Transmission	Unattended	500	230	0	1569	2	0	0	0	0
164	Red Lion-New Castle, DE 2	Distribution	Unattended	138	25	0	28	1	0	0	0	0
165	Red Lion Sub-Pencader Hd, DE	Transmission	Unattended	230	138	0	672	2	0	0	0	0
166	Rehoboth Sub-Rehoboth, DE 1	Transmission	Unattended	138	69	0	200	1	0	0	0	0
167	Rehoboth Sub-Rehoboth, DE 2	Distribution	Unattended	69	12	0	75	2	0	0	0	0
168	Reybold Sub-Red Lion Hd, DE 1	Transmission	Unattended	138	69	0	112	1	0	0	0	0
169	Reybold Sub-Red Lion Hd, DE 2	Distribution	Unattended	138	12	0	75	2	0	0	0	0
170	Rising Sun-Cecil, MD	Distribution	Unattended	35	4	0	7	2	0	0	0	0
171	Sharptown-Sharptown, MD	Distribution	Unattended	69	12	0	7	1	0	0	0	0
172	Silverbrook Sub, DE	Distribution	Unattended	138	35	0	184	2	0	0	0	0
173	Silverside Rd Sub-Brandywine Hd, DE 1	Distribution	Unattended	69	12	0	67	2	0	0	0	0
174	Silverside Rd Sub-Brandywine Hd, DE 2	Distribution	Unattended	69	35	0	56	1	0	0	0	0
175	S Harrington Sub-Harrington, DE	Transmission	Unattended	138	69	0	112	1	0	0	0	0
176	Steele-Denton, MD 1	Transmission	Unattended	230	138	0	856	3	0	138kV Capacitor Bank	2	41
177	Steele-Denton, MD 2	Distribution	Unattended	138	25	0	28	1	0	0	0	0
178	Stevensville, MD	Distribution	Unattended	69	25	0	98	2	0	0	0	0
179	Stockton-Stockton, MD	Distribution	Unattended	69	25	0	20	2	0	0	0	0
180	Sunset Lake Sub-Pencader Hd, DE 1	Distribution	Unattended	138	12	0	67	2	0	0	0	0
181	Sunset Lake Sub-Pencader Hd, DE 2	Distribution	Unattended	138	25	0	28	1	0	0	0	0
182	Sussex Sub-Georgetown, DE	Distribution	Unattended	69	12	0	48	2	0	0	0	0
183	Talleyville Sub-Brandywine Hd, DE	Distribution	Unattended	35	12	0	42	2	0	0	0	0
184	Talleyville, DE	Distribution	Unattended	138	12	0	56	1	0	0	0	0
185	Theodore-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
186	Todd-Hurlock, MD 1	Distribution	Unattended	69	25	0	56	2	0	0	0	0
187	Todd-Hurlock, MD 2	Distribution	Unattended	69	12	0	11	1	0	0	0	0
188	Townsend Sub-New Castle Hd, DE	Distribution	Unattended	138	25	0	56	1	0	138kV Capacitor Bank	2	7
189	Trappe-Trappe, MD	Distribution	Unattended	69	12	0	50	2	0	0	0	0
190	Triumph-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
191	Vienna-Vienna, MD 1	Transmission	Unattended	138	69	0	224	2	0	138kV Capacitor Bank	1	20
192	Vienna-Vienna, MD-Local	Distribution	Unattended	69	12	0	3	1	0	0	0	0
193	Vienna-Vienna, MD 2	Transmission	Unattended	230	138	0	448	1	0	0	0	0
194	Walnut-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
195	Wattsville-Wattsville, VA	Transmission	Unattended	138	69	0	225	1	0	0	0	0
196	West Sub-Christiana Hd, DE 1	Distribution	Unattended	69	35	0	112	2	0	0	0	0
197	West Sub-Christiana Hd, DE 2	Distribution	Unattended	69	12	0	112	2	0	0	0	0
198	West Cambridge, MD	Distribution	Unattended	69	12	0	22	1	0	0	0	0
199	West Wilmington-Wilm, DE	Distribution	Unattended	138	12	0	168	2	0	0	0	0
200	Whiteford-Harford, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
201	Woodlawn-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
202	Worcester-Berlin, MD 1	Distribution	Unattended	69	25	0	66	2	0	0	0	0
203	Worcester-Berlin, MD 2	Transmission	Unattended	138	69	0	224	1	0	0	0	0

204	Wye Mills, Wye Mills, MD 1	Transmission	Unattended	138	69	0	450	2	0	138kV Capacitor Bank	2	19
205	Wye Mills, Wye Mills, MD 2	Distribution	Unattended	69	25	0	56	2	0	0	0	0
206	Wyoming, Wyoming, DE	Distribution	Unattended	25	12	0	3	1	0	0	0	0
207	Spare - Bear	Distribution	Unattended	34	12	0	22	0	1	0	0	0
208	Spare - Carrcroft 1	Transmission	Unattended	138	36	0	84	0	1	0	0	0
209	Spare - Carrcroft 2	Distribution	Unattended	69	12	0	38	0	1	0	0	0
210	Spare - Cecil	Distribution	Unattended	35	4	0	4	0	1	0	0	0
211	Spare - Centerville	Distribution	Unattended	69	12	0	22	0	1	0	0	0
212	Spare - Christiana	Distribution	Unattended	138	12	0	56	0	1	0	0	0
213	Spare - Churchmans	Transmission	Unattended	138	12	0	84	0	1	0	0	0
214	Spare - Colora	Transmission	Unattended	35	4	0	4	0	1	0	0	0
215	Spare - Edgemoor	Distribution	Unattended	138	69	0	112	0	1	0	0	0
216	Spare - Hillsboro	Distribution	Unattended	138	25	0	28	0	1	0	0	0
217	Spare - Huron	Distribution	Unattended	69	24	0	75	0	1	0	0	0
218	Spare - Indian River 1	Distribution	Unattended	230	138	0	336	0	1	0	0	0
219	Spare - Indian River 2	Distribution	Unattended	230	16	0	150	0	1	0	0	0
220	Spare - Keeney-EHV 1	Transmission	Unattended	230	138	0	336	0	1	0	0	0
221	Spare - Keeney-EHV 2	Distribution	Unattended	230	35	0	112	0	1	0	0	0
222	Spare - Keeney-EHV 3	Transmission	Unattended	500	230	0	333	0	1	0	0	0
223	Spare - Keeney-EHV 4	Transmission	Unattended	230	138	0	448	0	2	0	0	0
224	Spare - Keeney-EHV 5	Transmission	Unattended	500	230	0	243	0	2	0	0	0
225	Spare - Kiamensi 1	Distribution	Unattended	138	36	0	56	0	2	0	0	0
226	Spare - Kiamensi 2	Distribution	Unattended	138	36	0	84	0	1	0	0	0
227	Spare - Kings Creek	Transmission	Unattended	69	12	0	20	0	1	0	0	0
228	Spare - Loretto	Distribution	Unattended	69	25	0	56	0	1	0	0	0
229	Spare - Mermaid 1	Distribution	Unattended	138	12	0	56	0	1	0	0	0
230	Spare - Mermaid 2	Distribution	Unattended	34	12	0	20	0	1	0	0	0
231	Spare - N. Seaford	Distribution	Unattended	69	12	0	38	0	1	0	0	0
232	Spare - Nelson 1	Distribution	Unattended	69	25	0	56	0	1	0	0	0
233	Spare - Nelson 2	Distribution	Unattended	138	16	0	150	0	1	0	0	0
234	Spare - New Castle	Distribution	Unattended	69	12	0	56	0	1	0	0	0
235	Spare - Orchard	Distribution	Unattended	500	230	0	336	0	1	0	0	0
236	Spare - S. Harrington 1	Distribution	Unattended	138	12	0	38	0	1	0	0	0
237	Spare - S. Harrington 2	Distribution	Unattended	138	25	0	38	0	1	0	0	0
238	Spare - S. Harrington 3	Transmission	Unattended	230	69	0	336	0	1	0	0	0
239	Spare - S. Harrington 4	Transmission	Unattended	138	69	0	225	0	1	0	0	0
240	Spare - Salisbury Warehouse	Distribution	Unattended	69	8	0	4	0	1	0	0	0
241	Spare - Theodore	Distribution	Unattended	34	4	0	4	0	1	0	0	0
242	Spare - Townsend	Distribution	Unattended	138	25	0	56	0	1	0	0	0
243	Spare - West	Distribution	Unattended	69	34	0	56	0	1	0	0	0
244	Mobile Unit D1	Distribution	Unattended	138	25	0	25	0	1	0	0	0
245	Mobile Unit D2	Distribution	Unattended	69	25	0	12	0	1	0	0	0
246	Mobile Unit D3	Distribution	Unattended	34	12	0	20	0	1	0	0	0
247	Mobile Unit D4	Distribution	Unattended	138	25	0	12	0	1	0	0	0
248	Mobile Unit D5	Distribution	Unattended	69	25	0	40	0	1	0	0	0
249	Mobile Unit D6	Distribution	Unattended	138	25	0	28		1	0		

250	Mobile Unit D7	Distribution	Unattended	69	25	0	30	0	1	0	0	0
251	Mobile Unit D8	Distribution	Unattended	69	12	0	27	0	1	0	0	0
252	Mobile Unit D9	Distribution	Unattended	138	12	0	21	0	1	0	0	0
253	Mobile Unit D10	Distribution	Unattended	138	25	0	30	0	1	0	0	0
254	Mobile Unit D11	Distribution	Unattended	138	25	0	30	0	1	0	0	0
255	Mobile Unit D12	Distribution	Unattended	69	12	0	20		1	0		

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	[a] PHI Service Company (PHISCO)			
3	Centralized Support Services	PHISCO	[c] Various	134,439,064
4	[b] Exelon Business Services Company (EBSC)			
5	Centralized Support Services	EBSC	[d] Various	126,847,716
6	Atlantic City Electric Co (ACE)			
7	Materials	ACE	[e] Various	1,292,512
8	Facility Services	ACE	184	5,474
9	Potomac Electric Power Company (Pepco)			
10	Materials	Pepco	[f] Various	738,067
11	Mutual Assistance	Pepco	[g] Various	159,392
12	Atlantic Southern Properties (ASP)			
13	Facility Services	ASP	184	880
14	PECO Energy Company (PECO)			
15	Information Technology Services	PECO	[h] Various	6,743
16	Extra-High Voltage (EHV) Transmission Agreement charges	PECO	571	3,041
17	Materials	PECO	154	2,088
18	Baltimore Gas & Electric Co. (BGE)			
19	Materials	BGE	[i] Various	42,715
20	Information Technology Services	BGE	[j] Various	5,110
21	Other Services	BGE	921	(184)
22	Commonwealth Edison Company (ComEd)			
23	Transmission System Operations Services	ComEd	560	30,929
24	Transmission Planning Services	ComEd	560	17,061
25	Legal Services	ComEd	921	18,753
26	Information Technology Services	ComEd	[k] Various	5,974

27	Materials	ComEd	[l] Various	816
28	Audit Services	ComEd	921	266
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Atlantic City Electric Co (ACE)			
22	Materials	ACE	154/163	1,645,729
23	Mutual Assistance	ACE	456	87,676
24	Meters Transfer	ACE	[m] Various	19,308
25	Facility Services	ACE	[n] Various	17,768
26	Baltimore Gas & Electric Co. (BGE)			
27	Mutual Assistance	BGE	456	20,018
28	Materials	BGE	154/163	63
29	Potomac Electric Power Company (PEPCO)			
30	Materials	PEPCO	154/163/232	1,394,002
31	Facility Services	PEPCO	[o] Various	10,753
32	PECO Energy Company (PECO)			
33	Materials	PECO	154/163	4,195
34	Commonwealth Edison Company (ComEd)			
35	Materials	ComEd	154/163	2,397
36	Exelon Business Services Company (EBSC)			
37	Facility Services	EBSC	[p] Various	1,378,321
38	Information Technology Services	EBSC	495	66,952
39	Vehicle Services	EBSC	456	40,272
40	PHI Service Company (PHISCO)			
41	Facility Services	PHISCO	[q] Various	3,427,291
42	Vehicle Services	PHISCO	456	1,235,218
43	Materials	PHISCO	154/163/232	9,139
42				

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2024	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

PHI Service Company (PHISCO) Overview

Services provided by PHISCO are provided under a Service Agreement with Delmarva Power & Light Company (DPL). Charges are provided by either direct charging of costs or are based on an allocation. The Service Agreement provides specific guidelines on the allocation methods used to charge these costs to the various PHI affiliates. Information on the Service Company allocation methods are explained in detail under Schedule XXI, Methods of Allocations, in the FERC Form 60 filed for PHISCO.

PHISCO provides a variety of services which include customer services, support services, financial services, human resources, legal services, information technology, governmental affairs, communication services, regulatory services, regulated gas and electric (transmission and distribution services), executive management, and supply services.

The services provided by the regulated gas and electric area include: system operations services; meter maintenance and testing; power procurement and energy planning; and other delivery services, including delivery senior management, asset management, engineering standards, distribution planning, engineering services for distribution, substation and transmission, system protection, project and construction management, electric maintenance, administrative support, process improvement, and performance analysis.

(b) Concept: DescriptionOfNonPowerGoodOrService

Exelon Business Services Company, LLC (EBSC) Overview

Services provided by EBSC are provided under a General Service Agreement with DPL. Charges are provided by either direct charging of costs or are based on an allocation. The factors for allocating the costs from EBSC to Exelon affiliates are contained in the General Services Agreement. Information on the EBSC allocation methods are explained in detail under Schedule XXI, Methods of Allocations, in the FERC Form 60 filed for EBSC.

EBSC provides a variety of support services, including: financial, human resources IT, communication, legal, governmental and regulatory affairs, executive, security, supply, Exelon Utilities, BSC Operations, real estate, and other.

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

PHISCO Centralized Support Services to DPL:

FERC Account	Amount	FERC Account	Amount	FERC Account	Amount
107	$ 26,679,268	584	4,056	878	569,436
108	3,417,571	586	1,144,817	879	(115)
163	624,094	587	459,727	880	603
182.3	809,573	588	3,016,285	881	9
184	1,985,283	589	1,155	885	(8)
254	21,469	591	4,399	887	460
416	13,608	592	141,381	892	405
426.1	314,680	593	1,368,930	893	277,150
426.3	(16,767)	594	47,713	894	(2)
426.4	18,991	595	5,347	902	196,302
426.5	690,888	596	15,040	903	41,500,022
557	1,047,509	597	903,633	908	2,360,581
560	791,048	598	35,363	909	6,853
561.2	2,868	813	97,659	910	184,282
566	680,984	843.9	(13)	923	42,399,086
569	8,256	850	16	924	20,015
570	109,258	856	46	925	1,515
571	256,018	857	425	928	783,382
573	3,508	859	1	930.1	524,640
580	496,425	860	6	930.2	318,038
581	72,574	863	279		
582	86	870	539	Total	$ 134,439,064
583	7,724	874	14,690		

(d) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

EBSC Centralized Support Services to DPL:

FERC Account	Amount	FERC Account	Amount	FERC Account	Amount
107	$ 45,893,651	589	1,506	875	13,600
108	786,570	591	12,774	878	86,477
163	1,229,550	592	120,453	879	4,096
184	842,306	593	756,751	880	1,460,384
416	121,267	594	95,333	881	35
417.1	1,171	595	22,056	885	(21)
426.1	300,614	596	24,901	887	43,486
426.3	(153,218)	597	42,713	889	810
426.4	67,990	598	17,249	892	44,269
426.5	315,705	807	14,051	893	23,205
557	3,281	813	35,607	894	906
560	7,605,304	840	216	902	139,674
561.2	7,348	841	80,515	903	13,202,288
566	713,626	843.4	81	908	903,484
569	4,854	843.6	435	910	79,113
570	198,148	843.9	3,346	921	309,043
571	1,461	850	3,189	923	45,452,662
573	13,474	851	64,886	924	771,146
580	19,897	856	15,024	925	13,391
581	164,136	857	7,219	928	10,239
582	79	859	420	930.1	279,424
583	43,052	860	1,528	930.2	14,059
584	41,140	863	35,942	935	8,539
586	296,515	870	8,018		
587	4,245	871	18,882	Total	$ 126,847,716
588	3,818,408	874	263,738		

(e) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

ACE Materials provided to DPL:

FERC Account	Amount
107	$ 313,358
108	58,489
154	918,277
583	2,388
Total	$ 1,292,512

(f) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Pepco Materials provided to DPL:

FERC Account	Amount
107	$ 124,501
108	12,230
154	561,935
560	(3)
569	3
593	48
598	39,353
Total	$ 738,067

(g) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Pepco Mutual Assistance provided to DPL:

FERC Account	Amount
107	$ 7,493
108	833
593	151,066
Total	$ 159,392

(h) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

PECO Information Technology Services provided to DPL:

FERC Account	Amount
107	$ 6,143
588	600

Total	$	6,743

(i) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

BGE Materials provided to DPL:

FERC Account		Amount
154	$	2,431
921		40,284
Total	$	42,715

(j) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

BGE Information Technology Services provided to DPL:

FERC Account		Amount
107	$	4,828
588		282
Total	$	5,110

(k) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

ComEd Information Technology Services provided to DPL:

FERC Account		Amount
107	$	5,432
588		542
Total	$	5,974

(l) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

ComEd Materials provided to DPL:

FERC Account		Amount
107	$	547
108		155
595		114
Total	$	816

(m) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

DPL Meters Transfer to ACE:

FERC Account		Amount
101	$	21,473
108		(2,165)
Total	$	19,308

(n) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

DPL Facility Services provided to ACE:

FERC Account		Amount
456	$	15,407
495		2,361
Total	$	17,768

(o) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

DPL Facility Services provided to Pepco:

FERC Account		Amount
456	$	9,324
495		1,429
Total	$	10,753

(p) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

DPL Facility Services provided to EBSC:

FERC Account		Amount
456	$	1,320,399
495		57,922
Total	$	1,378,321

(q) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

DPL Facility Services provided to PHISCO:

FERC Account		Amount
456	$	2,971,804
495		455,487
Total	$	3,427,291

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
DPL - Maryland	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	End of 2024/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	417,694,462	370,564,532
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	147,487,434	146,071,611
5	Large (or Ind.) (See Instr. 4)	11,935,852	11,565,098
6	(444) Public Street and Highway Lighting	4,486,449	4,363,910
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	581,604,197	532,565,151
11	(447) Sales for Resale	1,166,148	1,740,227
12	TOTAL Sales of Electricity	582,770,345	534,305,378
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. For Refunds	582,770,345	534,305,378
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,692,400	1,624,280
17	(451) Miscellaneous Service Revenues	234,661	260,193
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,974,939	1,872,292
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,888,003	5,019,793
22	(456.1) Revenues from Transmission of Electricity of Others	784,919	702,012
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	7,574,922	9,478,570
27	TOTAL Electric Operating Revenues	590,345,267	543,783,948

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

		MEGAWATT HOURS SOLD		AVG. NO. CUSTOMERS PER MONTH	
Line No.	Title of Account (a)	Year to Date Quarterly/ Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)
1	Sales of Electricity				
2	(440) Residential Sales	2,144,454	2,066,291	186,368	184,814
3	(442) Commercial and Industrial Sales				
4	Small (or Comm.) (See Instr. 4)	1,690,945	1,628,606	28,348	28,102
5	Large (or Ind.) (See Instr. 4)	326,629	323,608	135	142
6	(444) Public Street and Highway Lighting	10,411	10,422	260	257
7	(445) Other Sales to Public Authorities				
8	(446) Sales to Railroads and Railways				
9	(448) Interdepartmental Sales				
10	TOTAL Sales to Ultimate Consumers	4,172,439	4,028,927	215,111	213,315
11	(447) Sales for Resale	350,892	127,987		
12	TOTAL Sales of Electricity	4,523,331	4,156,914	215,111	213,315
13	(Less) (449.1) Provision for Rate Refunds				
14	TOTAL Revenues Net of Prov. For Refunds	4,523,331	4,156,914	215,111	213,315

Line 12, column (b) includes ($2,949,472) of unbilled revenues in 2024

Line 12, column (d) includes (2,924) MWH relating to unbilled revenues in 2024

FOOTNOTE DATA

Schedule Page: 300 Line No.: 21 Column: b

Items greater than $250,000:

$	1,143,262	MD Interconnection Fees
	761,464	Price Responsive Demand Credit
	733,113	MD Intracompany Power Sales
	(563,226)	MD Calendar Revenue Normalization
	440,299	MD Bill Stabilization Adjustment
	254,409	RPM Auction

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
DPL - Maryland	(1) ☒ An Original (2) ☐ A Resubmission		End of 2024/Q4

Schedule Page: 300 Line No.: 21 Column: c

Items greater than $250,000:

$	1,402,286	MD Bill Stabilization Adjustment
	1,909,419	MD Calendar Revenue Normalization
	(481,775)	MD Interconnection Fees
	545,072	Price Responsive Demand Credit
	931,846	MD Intracompany Power Sales
	364,672	Bonus Performance

DELMARVA POWER & LIGHT COMPANY
MARYLAND PROPERTY TAXES PAID
12/31/2024

Location	Rounded 2024 Taxes Paid	
Caroline County	1,176,684	
Cecil County	4,639,581	
City of Cambridge	246,813	
City of Crisfield	59,683	
City of Fruitland	163,931	
City of Salisbury	2,189,712	
Delmar	33,742	
Dorchester County	3,535,192	
Eldorado	-	
Galena	3,189	
Harford County	576,375	
Hebron	-	
Hillsboro	-	
Hurlock	-	
Kent County	1,196,211	
Mardela Springs	3,974	
Pocomoke City	171,699	
Preston	4,692	
Queen Anne's County	2,105,626	
Ridgely	18,176	
Secretary	6,678	
Sharptown	10,841	
Snow Hill	53,953	
Somerset County	1,017,642	
St. Michaels	43,250	
Sudlersville	-	
Talbot County	992,187	
Town of Betterton	3,790	
Town of Brookview	-	
Town of Cecilton	3,059	
Town of Centreville	1,162,194	
Town of Charlestown	-	
Town of Chesapeake City	11,922	
Town of Chestertown	48,672	
Town of Church Creek	380	
Town of Church Hill	33,867	
Town of Denton	61,040	
Town of East New Market	-	
Town of Elkton	194,581	
Town of Federalsburg	-	
Town of Goldsboro	1,324	
Town of Greensboro	-	
Town of Henderson	789	
Town of Hurlock	28,667	
Town of Marydel	1,426	
Town of Millington	3,701	
Town of North East	64,480	
Town of Ocean City	699,306	
Town of Perryville	28,727	
Town of Pittsville	13,258	
Town of Port Deposit	17,493	
Town of Prince Anne	232,573	
Town of Queen Anne	5,137	
Town of Queenstown	45,352	
Town of Rising Sun	24,147	
Town of Templeville	630	
Town of Trappe	8,931	
Town of Vienna	6,631	
Town of Willards	14,679	
Wicomico County	3,240,904	
Worcester County	2,730,891	
MD Other Property	300	*Filing fee to State of Maryland Department of Assessments*
Total	**26,938,682**	

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Quarterly Period Ended March 31, 2025
or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
001-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
001-01839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 10 South Dearborn Street Chicago, Illinois 60603-2300 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) 2301 Market Street P.O. Box 8699 Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
001-01910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	PEPCO HOLDINGS LLC (a Delaware limited liability company) 701 Ninth Street, N.W. Washington, District of Columbia 20068-0001 (202) 872-2000	52-2297449
001-01072	POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation) 701 Ninth Street, N.W. Washington, District of Columbia 20068-0001 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702-5440 (202) 872-2000	51-0084283
001-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702-5440 (202) 872-2000	21-0398280

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
EXELON CORPORATION:		
Common stock, without par value	EXC	The Nasdaq Stock Market LLC

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Exelon Corporation	Large Accelerated Filer ☒	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company	Emerging Growth Company
Commonwealth Edison Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer ☒	Smaller Reporting Company	Emerging Growth Company
PECO Energy Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer ☒	Smaller Reporting Company	Emerging Growth Company
Baltimore Gas and Electric Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer ☒	Smaller Reporting Company	Emerging Growth Company
Pepco Holdings LLC	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer ☒	Smaller Reporting Company	Emerging Growth Company
Potomac Electric Power Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer ☒	Smaller Reporting Company	Emerging Growth Company
Delmarva Power & Light Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer ☒	Smaller Reporting Company	Emerging Growth Company
Atlantic City Electric Company	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer ☒	Smaller Reporting Company	Emerging Growth Company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No ☒

The number of shares outstanding of each registrant’s common stock as of March 31, 2025 was:

Exelon Corporation Common Stock, without par value	1,009,535,664
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,418
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	not applicable
Potomac Electric Power Company Common Stock, $0.01 par value	100
Delmarva Power & Light Company Common Stock, $2.25 par value	1,000
Atlantic City Electric Company Common Stock, $3.00 par value	8,546,017

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
Registrants	Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL, and ACE, collectively
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
PCI	Potomac Capital Investment Corporation and its subsidiaries
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PHI Corporate	PHI in its corporate capacity as a holding company
PHISCO	PHI Service Company
Former Related Entities	
Constellation	Constellation Energy Corporation
Generation	Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC, a subsidiary of Exelon prior to separation on February 1, 2022)

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

Note - of the 2024 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2024 Annual Report on Form 10-K
ABO	Accumulated Benefit Obligation
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
ATM	At the market
BGS	Basic Generation Service
BSA	Bill Stabilization Adjustment
CEJA	Climate and Equitable Jobs Act; Illinois Public Act 102-0662 signed into law on September 15, 2021
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
CIP	Conservation Incentive Program
CMC	Carbon Mitigation Credit
CODMs	Chief Operating Decision Makers
DC PLUG	District of Columbia Power Line Undergrounding Initiative
DCPSC	Public Service Commission of the District of Columbia
DEPSC	Delaware Public Service Commission
DOEE	District of Columbia Department of Energy & Environment
DPA	Deferred Prosecution Agreement
DSIC	Distribution System Improvement Charge
EDIT	Excess Deferred Income Taxes
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974, as amended
ETAC	Energy Transition Assistance Charge
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate

GSA	Generation Supply Adjustment
GWhs	Gigawatt hours
ICC	Illinois Commerce Commission
IIJA	Infrastructure Investment and Jobs Act
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRA	Inflation Reduction Act
IRC	Internal Revenue Code
IRS	Internal Revenue Service
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
mmcf	Million Cubic Feet
MRP	Multi-Year Rate Plan
MWh	Megawatt hour

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

N/A	Not Applicable
NAV	Net Asset Value
NJBPU	New Jersey Board of Public Utilities
NOLC	Tax Net Operating Loss Carryforward
NPNS	Normal Purchase Normal Sale scope exception
NPS	National Park Service
NRD	Natural Resources Damages
OCI	Other Comprehensive Income
OPEB	Other Postretirement Employee Benefits
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
PLR	Private Letter Ruling
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
PP&E	Property, Plant, and Equipment
PRPs	Potentially Responsible Parties
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to regulatory agreements with the ICC and PAPUC
Rider	Reconcilable Surcharge Recovery Mechanism
ROE	Return on Equity
ROU	Right-of-use
RTO	Regional Transmission Organization
SEC	United States Securities and Exchange Commission
SOFR	Secured Overnight Financing Rate
SOS	Standard Offer Service
TCJA	Tax Cuts and Jobs Act
TSC	Transmission Service Charge

ZEC	Zero Emission Credit

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FILING FORMAT

This combined Form 10-Q is being filed separately 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). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This Report contains certain forward-looking statements within the meaning of federal securities laws 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. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that may cause our actual results or outcomes to differ materially from those contained in our forward-looking statements, including, but not limited to:

- unfavorable legislative and/or regulatory actions;
- uncertainty as to outcomes and timing of regulatory approval proceedings and/or negotiated settlements thereof;
- environmental liabilities and remediation costs;
- state and federal legislation requiring use of low-emission, renewable, and/or alternate fuel sources and/or mandating implementation of energy conservation programs requiring implementation of new technologies;
- challenges to tax positions taken, tax law changes, and difficulty in quantifying potential tax effects of business decisions;
- negative outcomes in legal proceedings;
- adverse impact of the activities associated with the past DPA and now-resolved SEC investigation on

Exelon’s and ComEd’s reputation and relationships with legislators, regulators, and customers;

- physical security and cybersecurity risks;
- extreme weather events, natural disasters, operational accidents such as wildfires or natural, gas explosions, war, acts and threats of terrorism, public health crises, epidemics, pandemics, or other significant events;
- disruptions or cost increases in the supply chain, including shortages in labor, materials or parts, or significant increases in relevant tariffs;
- lack of sufficient capacity to meet actual or forecasted demand or disruptions at power generation facilities owned by third parties;
- emerging technologies that could affect or transform the energy industry;
- instability in capital and credit markets;
- a downgrade of any Registrant’s credit ratings or other failure to satisfy the credit standards in the Registrants’ agreements or regulatory financial requirements;
- significant economic downturns or increases in customer rates;
- impacts of climate change and weather on energy usage and maintenance and capital costs; and

- impairment of long-lived assets, goodwill, and other assets.

New factors emerge from time to time, and it is impossible for us to predict all of such factors, nor can we assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. For more information, see those factors discussed in the 2024 Form 10-K filed by the Registrants, including in Part I, ITEM 1A. Risk Factors, and this Report including in Part II, ITEM 1A. Risk Factors.

Investors are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. 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 Report.

WHERE TO FIND MORE INFORMATION

The SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements, and other information that the Registrants file electronically with the SEC. These documents are also available to the public from commercial document retrieval services and free of charge at the Registrants' website at www.exeloncorp.com. Information contained on the Registrants' website shall not be deemed incorporated into, or to be a part of, this Report.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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Exelon Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income
(Unaudited)

(In millions, except per share data)	Three Months Ended March 31, 2025	2024
Operating revenues		
Electric operating revenues	$ 5,816	$ 5,198
Natural gas operating revenues	1,024	739
Revenues from alternative revenue programs	(126)	106
Total operating revenues	6,714	6,043
Operating expenses		
Purchased power	2,184	2,197
Purchased fuel	338	213
Operating and maintenance	1,347	1,271
Depreciation and amortization	903	879
Taxes other than income taxes	405	371
Total operating expenses	5,177	4,931
(Loss) gain on sale of assets	(1)	2
Operating income	1,536	1,114
Other income and (deductions)		
Interest expense, net	(504)	(462)
Interest expense to affiliates, net	(6)	(6)
Other, net	52	75
Total other income and (deductions)	(458)	(393)

Income before income taxes	1,078	721
Income taxes	170	63
Net income attributable to common shareholders	$ 908	$ 658
Comprehensive income, net of income taxes		
Net income	$ 908	$ 658
Other comprehensive income, net of income taxes		
Pension and non-pension postretirement benefit plans:		
Actuarial losses reclassified to periodic benefit cost	5	5
Pension and non-pension postretirement benefit plans valuation adjustments	5	(24)
Unrealized (loss) gain on cash flow hedges	(8)	33
Other comprehensive income	2	14
Comprehensive income attributable to common shareholders	$ 910	$ 672
Average shares of common stock outstanding:		
Basic	1,008	1,000
Assumed exercise and/or distributions of stock-based awards[(a)]	1	1
Diluted	1,009	1,001
Earnings per average common share		
Basic	$ 0.90	$ 0.66
Diluted	$ 0.90	$ 0.66

(a) The dilutive effects of stock-based compensation awards are calculated using the treasury stock method for all periods presented.

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Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows
(Unaudited)

	Three Months Ended March 31,	
(In millions)	**2025**	**2024**
Cash flows from operating activities		
Net income	$ 908	$ 658
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion	905	880
Loss (gain) on sales of assets	1	(2)
Deferred income taxes and amortization of investment tax credits	121	46
Net fair value changes related to derivatives	1	1
Other non-cash operating activities	344	39
Changes in assets and liabilities:		
Accounts receivable	(402)	(309)
Inventories	17	12
Accounts payable and accrued expenses	(397)	(238)
Collateral received, net	44	7

Income taxes	59	21
Regulatory assets and liabilities, net	86	252
Pension and non-pension postretirement benefit contributions	(292)	(111)
Other assets and liabilities	(195)	(264)
Net cash flows provided by operating activities	1,200	992
Cash flows from investing activities		
Capital expenditures	(1,946)	(1,767)
Proceeds from sales of assets	—	2
Other investing activities	4	(2)
Net cash flows used in investing activities	(1,942)	(1,767)
Cash flows from financing activities		
Changes in short-term borrowings	(775)	(317)
Proceeds from short-term borrowings with maturities greater than 90 days	—	150
Repayments on short-term borrowings with maturities greater than 90 days	—	(150)
Issuance of long-term debt	2,425	2,625
Retirement of long-term debt	—	(901)
Issuance of common stock	173	—
Dividends paid on common stock	(403)	(381)
Proceeds from employee stock plans	—	11
Other financing activities	(35)	(55)
Net cash flows provided by financing activities	1,385	982
Increase in cash, restricted cash, and cash equivalents	643	207
Cash, restricted cash, and cash equivalents at beginning of period	939	1,101
Cash, restricted cash, and cash equivalents at end of period	$ 1,582	$ 1,308
Supplemental cash flow information		
Decrease in capital expenditures not paid	(216)	(117)

See the Combined Notes to Consolidated Financial Statements

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Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents		$ 1,004		$ 357
Restricted cash and cash equivalents		578		541
Accounts receivable				
Customer accounts receivable	3,488		3,144	
Customer allowance for credit losses	(486)		(406)	
Customer accounts receivable, net		3,002		2,738
Other accounts receivable	1,127		1,123	

Other allowance for credit losses	(113)	(107)
Other accounts receivable, net	1,014	1,016
Inventories, net		
Fossil fuel	29	72
Materials and supplies	804	781
Regulatory assets	1,605	1,940
Prepaid renewable energy credits	240	494
Other	523	445
Total current assets	8,799	8,384
Property, plant, and equipment (net of accumulated depreciation and amortization of $18,958 and $18,445 as of March 31, 2025 and December 31, 2024 , respectively)	79,177	78,182
Deferred debits and other assets		
Regulatory assets	8,859	8,710
Goodwill	6,630	6,630
Receivable related to Regulatory Agreement Units	4,110	4,026
Investments	289	290
Other	1,620	1,562
Total deferred debits and other assets	21,508	21,218
Total assets	$ 109,484	$ 107,784

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 1,084	$ 1,859
Long-term debt due within one year	1,454	1,453
Accounts payable	2,693	2,994
Accrued expenses	1,186	1,468

Payables to affiliates	5	5
Customer deposits	465	446
Regulatory liabilities	464	411
Mark-to-market derivative liabilities	25	29
Unamortized energy contract liabilities	5	5
Renewable energy credit obligations	215	429
Other	507	512
Total current liabilities	8,103	9,611
Long-term debt	45,342	42,947
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,081	12,793
Regulatory liabilities	10,289	10,198
Pension obligations	1,475	1,745
Non-pension postretirement benefit obligations	480	472
Asset retirement obligations	305	301
Mark-to-market derivative liabilities	130	103
Unamortized energy contract liabilities	20	21
Other	2,262	2,282
Total deferred credits and other liabilities	28,042	27,915
Total liabilities	81,877	80,863
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 1,009 shares and 1,005 shares outstanding as of March 31, 2025 and December 31, 2024, respectively)	21,517	21,338
Treasury stock, at cost (2 shares as of March 31, 2025 and December 31, 2024)	(123)	(123)
Retained earnings	6,931	6,426
Accumulated other comprehensive loss, net	(718)	(720)
Total shareholders' equity	27,607	26,921
Total liabilities and shareholders' equity	$ 109,484	$ 107,784

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity
(Unaudited)

	Three Months Ended March 31, 2025					
(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Total Shareholders' Equity

Balance at December 31, 2024	1,007,046	$ 21,338	$ (123)	$ 6,426	$ (720)	$ 26,921
Net income	—	—	—	908	—	908
Long-term incentive plan activity	299	4	—	—	—	4
Employee stock purchase plan activity	(8)	2	—	—	—	2
Issuance of Common Stock	4,031	173	—	—	—	173
Common stock dividends ($0.40/common share)	—	—	—	(403)		(403)
Other comprehensive income, net of income taxes	—	—	—	—	2	2
Balance at March 31, 2025	1,011,368	$ 21,517	$ (123)	$ 6,931	$ (718)	$ 27,607

	Three Months Ended March 31, 2024					
(In millions, shares in thousands)	**Issued Shares**	**Common Stock**	**Treasury Stock**	**Retained Earnings**	**Accumulated Other Comprehensive Loss, net**	**Total Shareholders' Equity**
Balance at December 31, 2023	1,001,249	$ 21,114	$ (123)	$ 5,490	$ (726)	$ 25,755
Net income	—	—	—	658	—	658
Long-term incentive plan activity	333	2	—	—	—	2
Employee stock purchase plan activity	276	13	—	—	—	13
Common stock dividends ($0.38/common share)	—	—	—	(381)	—	(381)
Other comprehensive income, net of income taxes	—	—	—	—	14	14
Balance at March 31, 2024	1,001,858	$ 21,129	$ (123)	$ 5,767	$ (712)	$ 26,061

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Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	2024
Operating revenues		
Electric operating revenues	$ 2,142	$ 2,074
Revenues from alternative revenue programs	(85)	19
Operating revenues from affiliates	8	2
Total operating revenues	2,065	2,095
Operating expenses		
Purchased power	689	907
Operating and maintenance	323	318
Operating and maintenance from affiliates	100	100
Depreciation and amortization	380	362
Taxes other than income taxes	99	94
Total operating expenses	1,591	1,781
Operating income	474	314
Other income and (deductions)		
Interest expense, net	(125)	(119)
Interest expense to affiliates, net	(3)	(3)
Other, net	21	20
Total other income and (deductions)	(107)	(102)
Income before income taxes	367	212
Income taxes	65	19
Net income	$ 302	$ 193
Comprehensive income	$ 302	$ 193

See the Combined Notes to Consolidated Financial Statements

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Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	2024
Cash flows from operating activities		
Net income	$ 302	$ 193
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	380	362
Deferred income taxes and amortization of investment tax credits	(8)	(1)
Other non-cash operating activities	141	(6)
Changes in assets and liabilities:		
Accounts receivable	(111)	(133)
Receivables from and payables to affiliates, net	(21)	—
Inventories	3	(11)
Accounts payable and accrued expenses	(189)	(116)
Collateral received, net	5	8
Income taxes	72	21
Regulatory assets and liabilities, net	76	315
Pension and non-pension postretirement benefit contributions	(189)	(5)
Other assets and liabilities	(102)	(67)
Net cash flows provided by operating activities	359	560
Cash flows from investing activities		
Capital expenditures	(590)	(594)
Other investing activities	1	1
Net cash flows used in investing activities	(589)	(593)
Cash flows from financing activities		
Changes in short-term borrowings	311	128
Dividends paid on common stock	(203)	(194)
Contributions from parent	87	39
Other financing activities	—	1
Net cash flows provided by (used in) financing activities	195	(26)
Decrease in cash, restricted cash, and cash equivalents	(35)	(59)
Cash, restricted cash, and cash equivalents at beginning of period	632	686
Cash, restricted cash, and cash equivalents at end of period	$ 597	$ 627
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (25)	$ (74)

See the Combined Notes to Consolidated Financial Statements

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Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	96	$	105
Restricted cash and cash equivalents		501		486
Accounts receivable				
Customer accounts receivable	1,079		994	
Customer allowance for credit losses	(125)		(109)	
Customer accounts receivable, net		954		885
Other accounts receivable	291		290	
Other allowance for credit losses	(34)		(34)	
Other accounts receivable, net		257		256
Receivables from affiliates		8		4
Inventories, net		287		292
Regulatory assets		905		1,159
Other		154		141
Total current assets		3,162		3,328
Property, plant, and equipment (net of accumulated depreciation and amortization of $7,824 and $7,619 as of March 31, 2025 and December 31, 2024, respectively)		30,493		30,211
Deferred debits and other assets				
Regulatory assets		2,662		2,562
Goodwill		2,625		2,625
Receivable related to Regulatory Agreement Units		3,798		3,780
Investments		6		6
Prepaid pension asset		1,335		1,165
Other		1,118		1,073
Total deferred debits and other assets		11,544		11,211
Total assets	$	45,199	$	44,750

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 347	$ 36
Accounts payable	656	748
Accrued expenses	403	463
Payables to affiliates	60	77
Customer deposits	147	134
Regulatory liabilities	181	197
Mark-to-market derivative liabilities	25	29
Other	245	270
Total current liabilities	2,064	1,954
Long-term debt	12,031	12,030
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,646	5,601
Regulatory liabilities	8,490	8,421
Asset retirement obligations	169	167
Non-pension postretirement benefit obligations	158	156
Mark-to-market derivative liabilities	126	103
Other	1,243	1,232
Total deferred credits and other liabilities	15,832	15,680
Total liabilities	30,133	29,870
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	10,715	10,628
Retained earnings	2,763	2,664
Total shareholders' equity	15,066	14,880
Total liabilities and shareholders' equity	$ 45,199	$ 44,750

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity
(Unaudited)

	Three Months Ended March 31, 2025			
(In millions)	Common Stock	Other Paid-In Capital	Retained Earnings	Total Shareholders' Equity
Balance at December 31, 2024	$ 1,588	$ 10,628	$ 2,664	$ 14,880
Net income	—	—	302	302
Common stock dividends	—	—	(203)	(203)
Contributions from parent	—	87	—	87
Balance at March 31, 2025	$ 1,588	$ 10,715	$ 2,763	$ 15,066

	Three Months Ended March 31, 2024			
(In millions)	Common Stock	Other Paid-In Capital	Retained Earnings	Total Shareholders' Equity
Balance at December 31, 2023	$ 1,588	$ 10,401	$ 2,374	$ 14,363
Net income	—	—	193	193
Common stock dividends	—	—	(194)	(194)
Contributions from parent	—	39	—	39
Balance at March 31, 2024	$ 1,588	$ 10,440	$ 2,373	$ 14,401

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	2024
Operating revenues		
Electric operating revenues	$ 963	$ 782
Natural gas operating revenues	376	272
Revenues from alternative revenue programs	(9)	(2)
Operating revenues from affiliates	3	2
Total operating revenues	1,333	1,054
Operating expenses		
Purchased power	361	306
Purchased fuel	141	97
Operating and maintenance	266	235
Operating and maintenance from affiliates	61	58
Depreciation and amortization	109	104
Taxes other than income taxes	60	51
Total operating expenses	998	851
Gain on sales of assets	—	2
Operating income	335	205
Other income and (deductions)		
Interest expense, net	(59)	(52)
Interest expense to affiliates	(4)	(3)
Other, net	8	9
Total other income and (deductions)	(55)	(46)
Income before income taxes	280	159
Income taxes	14	10
Net income	$ 266	$ 149
Comprehensive income	$ 266	$ 149

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PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	2024
Cash flows from operating activities		
Net income	$ 266	$ 149
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	109	104
Gain on sales of assets	—	(2)
Deferred income taxes and amortization of investment tax credits	(18)	(8)
Other non-cash operating activities	54	20
Changes in assets and liabilities:		
Accounts receivable	(148)	(75)
Receivables from and payables to affiliates, net	(4)	4
Inventories	15	19
Accounts payable and accrued expenses	(25)	(63)
Collateral (paid) received, net	12	—
Income taxes	32	19
Regulatory assets and liabilities, net	27	(20)
Pension and non-pension postretirement benefit contributions	(9)	(2)
Other assets and liabilities	(117)	(104)
Net cash flows provided by operating activities	194	41
Cash flows from investing activities		
Capital expenditures	(424)	(361)
Other investing activities	2	2
Net cash flows used in investing activities	(422)	(359)
Cash flows from financing activities		
Changes in short-term borrowings	(192)	(165)
Dividends paid on common stock	(137)	(100)
Contributions from parent	563	580
Net cash flows provided by financing activities	234	315
Increase (decrease) in cash, restricted cash, and cash equivalents	6	(3)
Cash, restricted cash, and cash equivalents at beginning of period	48	51
Cash, restricted cash, and cash equivalents at end of period	$ 54	$ 48
Supplemental cash flow information		
(Decrease) increase in capital expenditures not paid	$ (20)	$ 5

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PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	54	$	48
Accounts receivable				
Customer accounts receivable	788		670	
Customer allowance for credit losses	(160)		(133)	
Customer accounts receivable, net		628		537
Other accounts receivable	170		145	
Other allowance for credit losses	(22)		(18)	
Other accounts receivable, net		148		127
Inventories, net				
Fossil fuel		15		37
Materials and supplies		83		79
Prepaid utility taxes		116		2
Prepaid renewable energy credits		31		51
Regulatory assets		61		65
Other		66		27
Total current assets		1,202		973
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,089 and $4,042 as of March 31, 2025 and December 31, 2024, respectively)		14,691		14,392
Deferred debits and other assets				
Regulatory assets		1,068		1,003
Receivable related to Regulatory Agreement Units		311		247
Investments		39		41
Prepaid pension asset		443		435
Other		35		32
Total deferred debits and other assets		1,896		1,758
Total assets	$	17,789	$	17,123

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PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 192
Long-term debt due within one year	350	350
Accounts payable	631	639
Accrued expenses	169	166
Payables to affiliates	37	41
Customer deposits	84	80
Regulatory liabilities	151	122
Other	120	80
Total current liabilities	1,542	1,670
Long-term debt	5,354	5,354
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,485	2,433
Regulatory liabilities	317	253
Asset retirement obligations	28	27
Non-pension postretirement benefit obligations	288	287
Other	84	100
Total deferred credits and other liabilities	3,202	3,100
Total liabilities	10,282	10,308
Commitments and contingencies		
Shareholder’s equity		
Common stock	5,208	4,645
Retained earnings	2,299	2,170
Total shareholder’s equity	7,507	6,815
Total liabilities and shareholder's equity	$ 17,789	$ 17,123

See the Combined Notes to Consolidated Financial Statements

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PECO Energy Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity
(Unaudited)

	Three Months Ended March 31, 2025		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2024	$ 4,645	$ 2,170	$ 6,815
Net income	—	266	266
Common stock dividends	—	(137)	(137)
Contributions from parent	563	—	563
Balance at March 31, 2025	$ 5,208	$ 2,299	$ 7,507

	Three Months Ended March 31, 2024		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2023	$ 4,050	$ 2,019	$ 6,069
Net income	—	149	149
Common stock dividends	—	(100)	(100)
Contributions from parent	580	—	580
Balance at March 31, 2024	$ 4,630	$ 2,068	$ 6,698

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Statements of Operations and Comprehensive Income
(Unaudited)

	Three Months Ended March 31,	
(In millions)	2025	2024
Operating revenues		
Electric operating revenues	$ 1,021	$ 857
Natural gas operating revenues	560	395
Revenues from alternative revenue programs	(29)	43
Operating revenues from affiliates	2	2
Total operating revenues	1,554	1,297
Operating expenses		
Purchased power	450	377
Purchased fuel	159	87
Operating and maintenance	242	205
Operating and maintenance from affiliates	63	59
Depreciation and amortization	164	150
Taxes other than income taxes	96	89
Total operating expenses	1,174	967
Operating income	380	330
Other income and (deductions)		
Interest expense, net	(58)	(50)
Other, net	9	8
Total other income and (deductions)	(49)	(42)
Income before income taxes	331	288
Income taxes	71	24
Net income	$ 260	$ 264
Comprehensive income	$ 260	$ 264

See the Combined Notes to Consolidated Financial Statements

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Baltimore Gas and Electric Company
Statements of Cash Flows
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	2024
Cash flows from operating activities		
Net income	$ 260	$ 264
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	164	150
Deferred income taxes and amortization of investment tax credits	35	(4)
Other non-cash operating activities	55	(21)
Changes in assets and liabilities:		
Accounts receivable	(153)	(95)
Receivables from and payables to affiliates, net	(10)	2
Inventories	20	14
Accounts payable and accrued expenses	(15)	21
Collateral received, net	1	—
Income taxes	36	29
Regulatory assets and liabilities, net	14	—
Pension and non-pension postretirement benefit contributions	(34)	(25)
Other assets and liabilities	49	(18)
Net cash flows provided by operating activities	422	317
Cash flows from investing activities		
Capital expenditures	(406)	(324)
Other investing activities	3	8
Net cash flows used in investing activities	(403)	(316)
Cash flows from financing activities		
Changes in short-term borrowings	62	70

Dividends paid on common stock	(98)	(92)
Net cash flows used in financing activities	(36)	(22)
Decrease in cash, restricted cash, and cash equivalents	(17)	(21)
Cash, restricted cash, and cash equivalents at beginning of period	34	48
Cash, restricted cash, and cash equivalents at end of period	$ 17	$ 27
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (48)	$ (8)

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Balance Sheets
(Unaudited)

(In millions)	March 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents		$ 14		$ 33
Restricted cash and cash equivalents		3		1
Accounts receivable				
Customer accounts receivable	805		654	
Customer allowance for credit losses	(72)		(56)	
Customer accounts receivable, net		733		598
Other accounts receivable	109		113	
Other allowance for credit losses	(6)		(6)	
Other accounts receivable, net		103		107
Inventories, net				
Fossil fuel		12		29
Materials and supplies		81		84
Prepaid utility taxes		58		115
Regulatory assets		156		207
Prepaid renewable energy credits		52		157
Other		17		17
Total current assets		1,229		1,348
Property, plant, and equipment (net of accumulated depreciation and amortization of $ 5,079 and $ 5,005 as of March 31, 2025 and December 31, 2024 , respectively)		13,358		13,134
Deferred debits and other assets				

Regulatory assets	798	788
Investments	10	10
Prepaid pension asset	231	218
Other	51	44
Total deferred debits and other assets	1,090	1,060
Total assets	$ 15,677	$ 15,542

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Balance Sheets
(Unaudited)

(In millions)	March 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 237	$ 175
Accounts payable	445	515
Accrued expenses	211	176
Payables to affiliates	38	48
Customer deposits	119	118
Regulatory liabilities	34	12
Renewable energy credit obligations	53	160
Other	39	39
Total current liabilities	1,176	1,243
Long-term debt	5,396	5,395
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,161	2,099
Regulatory liabilities	615	636
Asset retirement obligations	36	36
Non-pension postretirement benefit obligations	145	150
Other	100	97
Total deferred credits and other liabilities	3,057	3,018

Total liabilities	9,629	9,656
Commitments and contingencies		
Shareholder's equity		
Common stock	3,483	3,483
Retained earnings	2,565	2,403
Total shareholder's equity	6,048	5,886
Total liabilities and shareholder's equity	$ 15,677	$ 15,542

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Statements of Changes in Shareholder's Equity
(Unaudited)

	Three Months Ended March 31, 2025		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2024	$ 3,483	$ 2,403	$ 5,886
Net income	—	260	260
Common stock dividends	—	(98)	(98)
Balance at March 31, 2025	$ 3,483	$ 2,565	$ 6,048

	Three Months Ended March 31, 2024		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2023	$ 3,246	$ 2,244	$ 5,490
Net income	—	264	264
Common stock dividends	—	(92)	(92)
Balance at March 31, 2024	$ 3,246	$ 2,416	$ 5,662

See the Combined Notes to Consolidated Financial Statements

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Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income
(Unaudited)

	Three Months Ended March 31,	
(In millions)	2025	2024
Operating revenues		
Electric operating revenues	$ 1,691	$ 1,485
Natural gas operating revenues	88	72
Revenues from alternative revenue programs	(3)	46
Operating revenues from affiliates	2	3
Total operating revenues	1,778	1,606
Operating expenses		
Purchased power	684	607
Purchased fuel	38	29
Operating and maintenance	296	274
Operating and maintenance from affiliates	53	51

Depreciation and amortization	234	246
Taxes other than income taxes	140	128
Total operating expenses	1,445	1,335
Loss on sale of assets	(1)	—
Operating income	332	271
Other income and (deductions)		
Interest expense, net	(99)	(90)
Interest expense to affiliates, net	(1)	—
Other, net	19	27
Total other income and (deductions)	(81)	(63)
Income before income taxes	251	208
Income taxes	57	40
Net income	$ 194	$ 168
Comprehensive income	$ 194	$ 168

See the Combined Notes to Consolidated Financial Statements

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Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Cash Flows
(Unaudited)

	Three Months Ended March 31,	
(In millions)	2025	2024
Cash flows from operating activities		
Net income	$ 194	$ 168
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	234	246
Loss on sales of assets	1	—
Deferred income taxes and amortization of investment tax credits	32	16
Other non-cash operating activities	69	9
Changes in assets and liabilities:		

Accounts receivable	6	1
Receivables from and payables to affiliates, net	(9)	—
Inventories	(24)	(11)
Accounts payable and accrued expenses	(84)	(23)
Collateral received, net	27	—
Income taxes	25	24
Regulatory assets and liabilities, net	(14)	(42)
Pension and non-pension postretirement benefit contributions	(42)	(72)
Other assets and liabilities	(13)	(27)
Net cash flows provided by operating activities	402	289
Cash flows from investing activities		
Capital expenditures	(513)	(453)
Net cash flows used in investing activities	(513)	(453)
Cash flows from financing activities		
Changes in short-term borrowings	(530)	(394)
Issuance of long-term debt	425	925
Retirement of long-term debt	—	(400)
Changes in Exelon intercompany money pool	11	8
Distributions to member	(132)	(118)
Contributions from member	352	487
Other financing activities	(8)	(21)
Net cash flows provided by financing activities	118	487
Increase in cash, restricted cash, and cash equivalents	7	323
Cash, restricted cash, and cash equivalents at beginning of period	163	204
Cash, restricted cash, and cash equivalents at end of period	$ 170	$ 527
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (109)	$ (11)

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025	December 31, 2024
ASSETS		
Current assets		
Cash and cash equivalents	$ 127	$ 139
Restricted cash and cash equivalents	43	24
Accounts receivable		
Customer accounts receivable	815	827

Customer allowance for credit losses	(129)	(108)
Customer accounts receivable, net	686	719
Other accounts receivable	281	284
Other allowance for credit losses	(51)	(49)
Other accounts receivable, net	230	235
Receivables from affiliates	8	8
Inventories, net		
Fossil fuel	2	7
Materials and supplies	354	325
Prepaid utility taxes	39	70
Regulatory assets	297	323
Prepaid renewable energy credits	58	194
Other	56	36
Total current assets	1,900	2,080
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,892 and $3,728 as of March 31, 2025 and December 31, 2024, respectively)	20,258	20,053
Deferred debits and other assets		
Regulatory assets	1,577	1,570
Goodwill	4,005	4,005
Investments	152	152
Prepaid pension asset	266	252
Other	191	185
Total deferred debits and other assets	6,191	6,164
Total assets	$ 28,349	$ 28,297

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025	December 31, 2024
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 530

Long-term debt due within one year	292	290
Accounts payable	605	721
Accrued expenses	317	367
Payables to affiliates	57	66
Borrowings from Exelon intercompany money pool	74	63
Customer deposits	116	113
Regulatory liabilities	87	69
Unamortized energy contract liabilities	5	5
Renewable energy credit obligations	86	217
Other	128	124
Total current liabilities	1,767	2,565
Long-term debt	9,249	8,834
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,239	3,190
Regulatory liabilities	778	794
Asset retirement obligations	68	67
Non-pension postretirement benefit obligations	28	31
Unamortized energy contract liabilities	20	21
Other	464	473
Total deferred credits and other liabilities	4,597	4,576
Total liabilities	15,613	15,975
Commitments and contingencies		
Member's equity		
Membership interest	12,914	12,562
Undistributed losses	(178)	(240)
Total member's equity	12,736	12,322
Total liabilities and member's equity	$ 28,349	$ 28,297

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Changes in Member's Equity
(Unaudited)

Three Months Ended March 31, 2025

(In millions)	Membership Interest	Undistributed (Losses)/Gains	Total Member's Equity
Balance at December 31, 2024	$ 12,562	$ (240)	$ 12,322
Net income	—	194	194
Distributions to member	—	(132)	(132)
Contributions from member	352	—	352
Balance at March 31, 2025	$ 12,914	$ (178)	$ 12,736

	Three Months Ended March 31, 2024		
(In millions)	Membership Interest	Undistributed (Losses)/Gains	Total Member's Equity
Balance at December 31, 2023	$ 12,057	$ (275)	$ 11,782
Net income	—	168	168
Distributions to member	—	(118)	(118)
Contributions from member	487	—	487
Balance at March 31, 2024	$ 12,544	$ (225)	$ 12,319

See the Combined Notes to Consolidated Financial Statements

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Potomac Electric Power Company

Statements of Operations and Comprehensive Income
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	2024
Operating revenues		
Electric operating revenues	$ 855	728
Revenues from alternative revenue programs	2	29
Operating revenues from affiliates	2	2
Total operating revenues	859	759
Operating expenses		
Purchased power	318	281
Operating and maintenance	96	86
Operating and maintenance from affiliates	63	64
Depreciation and amortization	105	107
Taxes other than income taxes	113	102
Total operating expenses	695	640
Loss on sale of assets	(1)	—
Operating income	163	119
Other income and (deductions)		
Interest expense, net	(52)	(45)
Other, net	11	15
Total other income and (deductions)	(41)	(30)
Income before income taxes	122	89
Income taxes	25	14
Net income	$ 97	$ 75
Comprehensive income	$ 97	$ 75

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements Of Cash Flows
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024
Cash flows from operating activities		
Net income	$ 97	$ 75
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	105	107
Deferred income taxes and amortization of investment tax credits	10	3
Loss on sales of assets	1	—
Other non-cash operating activities	12	(13)
Changes in assets and liabilities:		
Accounts receivable	(14)	21
Receivables from and payables to affiliates, net	(2)	6
Inventories	(20)	(10)
Accounts payable and accrued expenses	(28)	—
Collateral received (paid), net	10	(1)
Income taxes	15	12
Regulatory assets and liabilities, net	13	6
Pension and non-pension postretirement benefit contributions	(4)	(4)
Other assets and liabilities	(3)	(19)
Net cash flows provided by operating activities	192	183
Cash flows from investing activities		
Capital expenditures	(240)	(229)
Changes in PHI intercompany money pool	—	(134)
Net cash flows used in investing activities	(240)	(363)
Cash flows from financing activities		
Changes in short-term borrowings	(200)	(132)
Issuance of long-term debt	200	675
Retirement of long-term debt	—	(400)
Dividends paid on common stock	(66)	(51)
Contributions from parent	157	251
Other financing activities	(5)	(15)
Net cash flows provided by financing activities	86	328
Increase in cash, restricted cash, and cash equivalents	38	148
Cash, restricted cash, and cash equivalents at beginning of period	51	72
Cash, restricted cash, and cash equivalents at end of period	$ 89	$ 220
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (49)	$ (11)

Potomac Electric Power Company
Balance Sheets
(Unaudited)

(In millions)	March 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	58	$	30
Restricted cash and cash equivalents		31		21
Accounts receivable				
Customer accounts receivable	404		395	
Customer allowance for credit losses	(69)		(59)	
Customer accounts receivable, net		335		336
Other accounts receivable	147		142	
Other allowance for credit losses	(27)		(27)	
Other accounts receivable, net		120		115
Receivables from affiliates		—		1
Inventories, net		189		169
Regulatory assets		136		157
Prepaid renewable energy credits		49		165
Other		37		55
Total current assets		955		1,049
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,593 and $4,522 as of March 31, 2025 and December 31, 2024, respectively)		10,205		10,097
Deferred debits and other assets				
Regulatory assets		442		446
Investments		136		135
Prepaid pension asset		216		222
Other		57		51
Total deferred debits and other assets		851		854
Total assets	$	12,011	$	12,000

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Potomac Electric Power Company
Balance Sheets
(Unaudited)

(In millions)	March 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 200
Long-term debt due within one year	6	6
Accounts payable	303	360
Accrued expenses	192	201
Payables to affiliates	34	37
Customer deposits	57	55
Regulatory liabilities	16	17
Merger related obligation	21	22
Renewable energy credit obligations	50	169
Other	43	51
Total current liabilities	722	1,118
Long-term debt	4,553	4,356
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,530	1,509
Regulatory liabilities	301	310
Asset retirement obligations	50	49
Other	232	223
Total deferred credits and other liabilities	2,113	2,091
Total liabilities	7,388	7,565
Commitments and contingencies		
Shareholder's equity		
Common stock	3,492	3,335
Retained earnings	1,131	1,100
Total shareholder's equity	4,623	4,435
Total liabilities and shareholder's equity	$ 12,011	$ 12,000

See the Combined Notes to Consolidated Financial Statements

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Potomac Electric Power Company
Statements Of Changes In Shareholder's Equity
(Unaudited)

	Three Months Ended March 31, 2025		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2024	$ 3,335	$ 1,100	$ 4,435
Net income	—	97	97
Common stock dividends	—	(66)	(66)
Contributions from parent	157	—	157
Balance at March 31, 2025	$ 3,492	$ 1,131	$ 4,623

	Three Months Ended March 31, 2024		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2023	$ 3,075	$ 1,069	$ 4,144
Net income	—	75	75
Common stock dividends	—	(51)	(51)
Contributions from parent	251	—	251
Balance at March 31, 2024	$ 3,326	$ 1,093	$ 4,419

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Delmarva Power & Light Company
Statements of Operations and Comprehensive Income
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	2024
Operating revenues		
Electric operating revenues	$ 463	$ 413
Natural gas operating revenues	88	72
Revenues from alternative revenue programs	(5)	4
Operating revenues from affiliates	2	2
Total operating revenues	548	491
Operating expenses		
Purchased power	209	186
Purchased fuel	38	29
Operating and maintenance	60	51
Operating and maintenance from affiliates	46	44
Depreciation and amortization	63	61
Taxes other than income taxes	21	20
Total operating expenses	437	391
Operating income	111	100
Other income and (deductions)		
Interest expense, net	(25)	(22)
Other, net	4	5
Total other income and (deductions)	(21)	(17)
Income before income taxes	90	83
Income taxes	21	17
Net income	$ 69	$ 66
Comprehensive income	$ 69	$ 66

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Delmarva Power & Light Company
Statements Of Cash Flows
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	2024
Cash flows from operating activities		
Net income	$ 69	$ 66
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	63	61
Deferred income taxes and amortization of investment tax credits	9	6
Other non-cash operating activities	21	12
Changes in assets and liabilities:		
Accounts receivable	(1)	(7)
Receivables from and payables to affiliates, net	(4)	—
Inventories	(4)	1
Accounts payable and accrued expenses	(9)	16
Collateral received, net	9	—
Income taxes	13	10
Regulatory assets and liabilities, net	2	(1)
Other assets and liabilities	7	6
Net cash flows provided by operating activities	175	170
Cash flows from investing activities		
Capital expenditures	(156)	(134)
Changes in PHI intercompany money pool	(12)	—
Net cash flows used in investing activities	(168)	(134)
Cash flows from financing activities		
Changes in short-term borrowings	(144)	(63)
Issuance of long-term debt	125	175
Dividends paid on common stock	(46)	(45)
Contributions from parent	99	154
Other financing activities	(3)	(3)
Net cash flows provided by financing activities	31	218
Increase in cash, restricted cash, and cash equivalents	38	254
Cash, restricted cash, and cash equivalents at beginning of period	23	16
Cash, restricted cash, and cash equivalents at end of period	$ 61	$ 270
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (47)	$ (6)

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Delmarva Power & Light Company
Balance Sheets
(Unaudited)

(In millions)	March 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	50	$	21
Restricted cash and cash equivalents		11		2
Accounts receivable				
Customer accounts receivable	215		210	
Customer allowance for credit losses	(23)		(17)	
Customer accounts receivable, net		192		193
Other accounts receivable	53		63	
Other allowance for credit losses	(9)		(9)	
Other accounts receivable, net		44		54
Receivables from affiliates		1		—
Receivable from PHI intercompany pool		12		—
Inventories, net				
Fossil fuel		2		6
Materials and supplies		103		95
Prepaid utility taxes		13		26
Regulatory assets		49		60
Prepaid renewable energy credits		9		29
Other		21		16
Total current assets		507		502
Property, plant, and equipment (net of accumulated depreciation and amortization of $2,121 and $ 2,075 as of March 31, 2025 and December 31, 2024 , respectively)		5,595		5,540
Deferred debits and other assets				
Regulatory assets		220		215
Prepaid pension asset		116		120
Other		46		44
Total deferred debits and other assets		382		379
Total assets	$	6,484	$	6,421

Delmarva Power & Light Company
Balance Sheets
(Unaudited)

(In millions)	March 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 144
Long-term debt due within one year	131	130
Accounts payable	131	187
Accrued expenses	65	55
Payables to affiliates	23	26
Customer deposits	34	34
Regulatory liabilities	46	42
Renewable energy credit obligations	37	48
Other	27	22
Total current liabilities	494	688
Long-term debt	2,215	2,090
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	960	946
Regulatory liabilities	323	325
Asset retirement obligations	13	13
Non-pension postretirement benefit obligations	3	3
Other	112	114
Total deferred credits and other liabilities	1,411	1,401
Total liabilities	4,120	4,179
Commitments and contingencies		
Shareholder's equity		
Common stock	1,714	1,615
Retained earnings	650	627
Total shareholder's equity	2,364	2,242
Total liabilities and shareholder's equity	$ 6,484	$ 6,421

See the Combined Notes to Consolidated Financial Statements

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Delmarva Power & Light Company
Statements Of Changes In Shareholder's Equity
(Unaudited)

(In millions)	Three Months Ended March 31, 2025		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2024	$ 1,615	$ 627	$ 2,242
Net income	—	69	69
Common stock dividends	—	(46)	(46)
Contributions from parent	99	—	99
Balance at March 31, 2025	$ 1,714	$ 650	$ 2,364

(In millions)	Three Months Ended March 31, 2024		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2023	$ 1,455	$ 638	$ 2,093
Net income	—	66	66
Common stock dividends	—	(45)	(45)
Contributions from parent	154	—	154
Balance at March 31, 2024	$ 1,609	$ 659	$ 2,268

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Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Operations and Comprehensive Income
(Unaudited)

	Three Months Ended March 31,	
(In millions)	2025	2024
Operating revenues		
Electric operating revenues	$ 372	$ 344
Revenues from alternative revenue programs	—	13
Operating revenues from affiliates	1	1
Total operating revenues	373	358
Operating expenses		
Purchased power	157	140
Operating and maintenance	51	47
Operating and maintenance from affiliates	39	40
Depreciation and amortization	64	74
Taxes other than income taxes	2	2
Total operating expenses	313	303
Operating income	60	55
Other income and (deductions)		
Interest expense, net	(21)	(20)
Other, net	3	5
Total other income and (deductions)	(18)	(15)
Income before income taxes	42	40
Income taxes	11	11
Net income	$ 31	$ 29
Comprehensive income	$ 31	$ 29

See the Combined Notes to Consolidated Financial Statements

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Atlantic City Electric Company and Subsidiary Company
Statements Of Cash Flows
(Unaudited)

(In millions)	Three Months Ended March 31, 2025	2024
Cash flows from operating activities		
Net income	$ 31	$ 29
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	64	74
Deferred income taxes and amortization of investment tax credits	8	7
Other non-cash operating activities	25	2
Changes in assets and liabilities:		
Accounts receivable	21	(12)
Receivables from and payables to affiliates, net	(2)	(5)
Inventories	—	(3)
Accounts payable and accrued expenses	(8)	(1)
Collateral received, net	6	1
Income taxes	3	3
Regulatory assets and liabilities, net	(28)	(47)
Pension and non-pension postretirement benefit contributions	(3)	(7)
Other assets and liabilities	(5)	(13)
Net cash flows provided by operating activities	112	28
Cash flows from investing activities		
Capital expenditures	(105)	(89)
Net cash flows used in investing activities	(105)	(89)
Cash flows from financing activities		
Changes in short-term borrowings	(186)	(199)

Issuance of long-term debt	100	75
Changes in PHI intercompany money pool	12	134
Dividends paid on common stock	(20)	(22)
Contributions from parent	94	81
Other financing activities	(2)	(2)
Net cash flows (used in) provided by financing activities	(2)	67
Increase in cash and cash equivalents	5	6
Cash and cash equivalents at beginning of period	14	21
Cash and cash equivalents at end of period	$ 19	$ 27
Supplemental cash flow information		
(Decrease) increase in capital expenditures not paid	$ (12)	$ 4

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	18	$	14
Restricted cash and cash equivalents		1		—
Accounts receivable				
Customer accounts receivable	196		223	
Customer allowance for credit losses	(37)		(32)	
Customer accounts receivable, net		159		191
Other accounts receivable	81		79	
Other allowance for credit losses	(15)		(13)	
Other accounts receivable, net		66		66
Receivables from affiliates		7		7
Inventories, net		62		62
Regulatory assets		107		101
Other		8		6
Total current assets		428		447
Property, plant, and equipment (net of accumulated depreciation and amortization of $1,839 and $ 1,798 as of March 31, 2025 and December 31, 2024 , respectively)		4,407		4,366
Deferred debits and other assets				
Regulatory assets		515		502

Prepaid pension asset	2	1
Other	35	33
Total deferred debits and other assets	552	536
Total assets	$ 5,387	$ 5,349

See the Combined Notes to Consolidated Financial Statements

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Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets
(Unaudited)

(In millions)	March 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 186
Long-term debt due within one year	154	154
Accounts payable	162	163
Accrued expenses	43	52
Payables to affiliates	20	22
Borrowings from PHI intercompany money pool	12	—
Customer deposits	24	24
Regulatory liabilities	25	10
Other	18	10
Total current liabilities	458	621
Long-term debt	1,879	1,779
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	825	816
Regulatory liabilities	141	146
Other	54	62

Total deferred credits and other liabilities	1,020	1,024
Total liabilities	3,357	3,424
Commitments and contingencies		
Shareholder's equity		
Common stock	2,009	1,915
Retained earnings	21	10
Total shareholder's equity	2,030	1,925
Total liabilities and shareholder's equity	$ 5,387	$ 5,349

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements Of Changes In Shareholder's Equity
(Unaudited)

	Three Months Ended March 31, 2025		
(In millions)	Common Stock	Retained (Deficit) Earnings	Total Shareholder's Equity
Balance at December 31, 2024	$ 1,915	$ 10	$ 1,925
Net income	—	31	31
Common stock dividends	—	(20)	(20)
Contributions from parent	94	—	94
Balance at March 31, 2025	$ 2,009	$ 21	$ 2,030

	Three Months Ended March 31, 2024		
(In millions)	Common Stock	Retained (Deficit) Earnings	Total Shareholder's Equity
Balance at December 31, 2023	$ 1,830	$ (18)	$ 1,812
Net income	—	29	29

Common stock dividends	—	(22)	(22)
Contributions from parent	81	—	81
Balance at March 31, 2024	$ 1,911	$ (11)	$ 1,900

See the Combined Notes to Consolidated Financial Statements

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1. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

Exelon is a utility services holding company engaged in the energy transmission and distribution businesses through ComEd, PECO, BGE, Pepco, DPL, and ACE.

Name of Registrant	Business	Service Territories
Commonwealth Edison Company	Purchase and regulated retail sale of electricity	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)

(Dollars in millions, except per share data, unless otherwise noted)

	Transmission and distribution of electricity and distribution of natural gas to retail customers	
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments Pepco, DPL, and ACE	Service Territories of Pepco, DPL, and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland
	Transmission and distribution of electricity to retail customers	
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	

Basis of Presentation (All Registrants)

This is a combined quarterly report of all Registrants. The Notes to the Consolidated Financial Statements apply to the Registrants as indicated parenthetically next to each corresponding disclosure. When appropriate, the Registrants are named specifically for their related activities and disclosures. Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology, and supply management services. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, finance, engineering, customer operations, transmission and distribution planning, asset management, system operations, and power procurement, to PHI operating Registrants. The costs of BSC and PHISCO are directly charged or allocated to the applicable subsidiaries. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

The accompanying consolidated financial statements as of March 31, 2025 and for the three months ended March 31, 2025 and 2024 are unaudited but, in the opinion of each Registrant's management, the Registrants include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2024 Consolidated Balance Sheets were derived from audited financial statements. The interim financial statements are to be read in conjunction with prior annual financial statements and notes. Additionally, financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2025. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial

statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

New Accounting Standards (All Registrants)

New Accounting Standards Issued and Not Yet Adopted as of March 31, 2025: The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by the Registrants in their consolidated financial statements as of March 31, 2025. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) in their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation that such standards will not significantly impact the Registrants' financial reporting.

(Dollars in millions, except per share data, unless otherwise noted)

Improvement to Income Tax Disclosures (Issued December 2023). Provides additional disclosure requirements related to the effective tax rate reconciliation and income taxes paid. Under the revised guidance for the effective tax reconciliations, entities would be required to disclose: (1) eight specific categories in the effective tax rate reconciliation in both percentages and reporting currency amount, (2) additional information for reconciling items over a certain threshold, (3) explanation of individual reconciling items disclosed, and (4) provide a qualitative description of the state and local jurisdictions that contribute to the majority of the state income tax expense. For each annual period presented, the new standard requires disclosure of the year-to-date amount of income taxes paid (net of refunds received) disaggregated by federal, state, and foreign. It also requires additional disaggregated information on income taxes paid (net of refunds received) to an individual jurisdiction equal to or greater than 5% of total income taxes paid (net of refunds received). The standard is effective for annual periods beginning January 1, 2025, with early adoption permitted.

Disaggregation of Income Statement Expenses (Issued November 2024). Provides additional disclosure requirements related to relevant expense captions of income statement expense line items. The revised guidance requires a new tabular disclosure of disaggregated income statement expenses including a break out of (1) purchases of inventory, (2) employee compensation, (3) depreciation, (4) intangible asset amortization, (5) depreciation, depletion, and amortization recognized as part of oil and gas producing activities included in each relevant expense line item on the income statement. The tabular disaggregation should include certain amounts already required to be disclosed under GAAP elsewhere. Any remaining amounts not separately disaggregated quantitatively should include a qualitative description. Additionally, on an annual basis, the standard requires disclosure of management's definition of selling expenses and the amount of expense. The standard is effective January 1, 2027, with early adoption permitted. The Registrants are currently assessing the impacts of this standard.

2. Regulatory Matters (All Registrants)

As discussed in Note 3 — Regulatory Matters of the 2024 Form 10-K, the Registrants are involved in rate and regulatory proceedings at FERC and their state commissions. The following discusses developments in 2025 and updates to the 2024 Form 10-K.

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Distribution Base Rate Case Proceedings

The following tables show the completed and pending distribution base rate case proceedings in 2025.

Completed Distribution Base Rate Case Proceedings

Registrant/ Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date

ComEd - Illinois	January 17, 2023[(a)]	Electric	$ 1,487	$ 1,045	8.905%	December 19, 2024	January 1, 2024
	April 26, 2024 (amended on September 11, 2024)[(b)]	Electric	$ 624	$ 623	9.89%	October 31, 2024	January 1, 2025
PECO - Pennsylvania	March 28, 2024	Electric[(c)(d)]	$ 464	$ 354	N/A[(e)]	December 12, 2024	January 1, 2025
		Natural Gas[(d)]	$ 111	$ 78			
BGE - Maryland[(f)]	February 17, 2023	Electric	$ 313	$ 179	9.50%	December 14, 2023	January 1, 2024
		Natural Gas	$ 289	$ 229	9.45%		
Pepco - District of Columbia[(g)]	April 13, 2023 (amended February 27, 2024)	Electric	$ 186	$ 123	9.50%	November 26, 2024	January 1, 2025
Pepco - Maryland[(h)]	May 16, 2023 (amended February 23, 2024)	Electric	$ 111	$ 45	9.50%	June 10, 2024	April 1, 2024
DPL - Maryland[(i)]	May 19, 2022	Electric	$ 38	$ 29	9.60%	December 14, 2022	January 1, 2023
DPL - Delaware[(j)]	December 15, 2022 (amended September 29, 2023)	Electric	$ 39	$ 28	9.60%	April 18, 2024	July 15, 2023
ACE - New Jersey[(k)]	February 15, 2023 (amended August 21, 2023)	Electric	$ 92	$ 45	9.60%	November 17, 2023	December 1, 2023

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(a) Reflects a four-year cumulative multi-year rate plan for January 1, 2024 to December 31, 2027. The MRP was originally approved by the ICC on December 14, 2023 and was subsequently amended on January 10, 2024, April 18, 2024 and December 19, 2024. The December 19, 2024 order provided a total revenue requirement increase of $1.045 billion inclusive of rate increases of approximately $752 million in 2024, $80 million in 2025, $102 million in 2026, and $111 million in 2027. On March 20, 2025, ComEd filed its annual revenue balancing reconciliation for 2024. This reconciliation, which is a component of revenue decoupling, reflected a revenue reduction of $55 million, effective January 1, 2026. On April 29, 2025, ComEd filed its 2024 MRP Reconciliation reflecting a revenue increase of $268 million, which includes the tax benefit of NOLCs. While NOLCs were included in the MRP Reconciliation, the impacts of the NOLCs will not be reflected in the financial statements until the PLR is received from the IRS. See Note 6 — Income Taxes for additional information on NOLCs.

(b) On October 31, 2024, the Delivery Reconciliation Amount for 2023 defined in Rider Delivery Service Pricing Reconciliation (Rider DSPR) was approved. Rider DSPR allows for the reconciliation of the revenue requirement in effect in the final years in which formula rates are determined and until such time as new rates are established under ComEd's approved MRP. The 2024 order reconciled the delivery service rates in effect in 2023 with the actual delivery service costs incurred in 2023. The reconciliation revenue requirement provides for a weighted average debt and equity return on distribution rate base of 7.02%, inclusive of an allowed ROE of 9.89%, reflecting the monthly yields on 30-year treasury bonds plus 580 basis points.

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(c) PECO's approved annual electric revenue requirement increase of $354 million is partially offset by a one-time credit of $64 million in January 2025. In addition, the PAPUC approved the recovery of storm damage costs incurred by PECO in 2024, up to $23 million, subject to review for reasonableness and prudency in PECO's next distribution rate case.

(d) On December 12, 2024, the PAPUC issued their Opinions and Orders which approved the non-unanimous partial settlements with limited modifications for both the electric and natural gas base rate cases, and denied the Weather Normalization Adjustment requested in the natural gas base rate case.

(Dollars in millions, except per share data, unless otherwise noted)

(e) The PECO electric and natural gas base rate case proceedings were resolved through settlement agreements, which did not specify an approved ROE.

(f) Reflects a three-year cumulative multi-year plan for January 1, 2024 through December 31, 2026. The MDPSC awarded BGE electric revenue requirement increases of $41 million, $113 million, and $25 million in 2024, 2025, and 2026, respectively, and natural gas revenue requirement increases of $126 million, $62 million, and $41 million in 2024, 2025, and 2026, respectively. Requested revenue requirement increases will be used to recover capital investments designed to increase the resilience of the electric and gas distribution systems and support Maryland's climate and regulatory initiatives. The MDPSC also approved a portion of the requested 2021 and 2022 reconciliation amounts, which will be recovered through separate electric and gas riders between March 2024 through February 2025. As such, the reconciliation amounts are not included in the approved revenue requirement increases. The 2021 reconciliation amounts are $13 million and $7 million for electric and gas, respectively, and the 2022 reconciliation amounts are $39 million and $15 million for electric and gas, respectively. In April 2024, BGE filed with the MDPSC its request for recovery of the 2023 reconciliation amounts of $79 million and $73 million for electric and gas, respectively, with supporting testimony and schedules.

(g) Reflects a two-year cumulative multi-year plan for January 1, 2025, through December 31, 2026. The DCPSC awarded Pepco electric incremental revenue requirement increases of $99 million and $24 million for 2025 and 2026, respectively.

(h) Reflects the amounts requested (before offsets) and awarded for a one-year multi-year plan for April 1, 2024 through March 31, 2025. The MDPSC awarded Pepco an electric incremental revenue requirement increase of $45 million for the 12-month period ending March 31, 2025. The MDPSC did not adopt the requested revenue requirement increases of $80 million (before offsets), $51 million, and $14 million as filed for 2025, 2026, and the 2027 nine-month extension period, respectively. The MDPSC also approved the requested reconciliation amounts for the 12-month periods ending March 31, 2022, and March 31, 2023, which will be recovered through a rider between August 2024 through March 2026. As such, the reconciliation amounts are not included in the approved revenue requirement increases. The reconciliation amounts are $1 million and $7 million, respectively, for the 12-month periods ending March 31, 2022, and March 31, 2023. In July 2024, Pepco filed its request with the MDPSC for recovery of $31 million for the 12-month period ended March 31, 2024, with supporting testimony and schedules.

(i) Reflects a three-year cumulative multi-year plan for January 1, 2023 through December 31, 2025. The MDPSC awarded DPL electric incremental revenue requirement increases of $17 million, $6 million, and $6 million for 2023, 2024, and 2025, respectively.

(j) On April 18, 2024, the DEPSC approved the Significant Storm Expense Rate Rider (Rider SSER) which will allow DPL to recover expenses associated with qualified storms. A qualified storm will be an individual storm for which DPL incurs expenses between $5 million and $15 million. The Rider SSER allows DPL to recover significant storm damage expenses for the previous 12-month period over a future 24-month period. For individual storm events for which DPL incurs expenses of more than $15 million, the future recovery period will be evaluated on a case-by-case basis and the unamortized balance will earn a return at DPL's authorized long-term cost of debt. The Rider SSER will have an annual true-up filing, subject to DEPSC review and approval.

(k) Requested and approved increases are before New Jersey sales and use tax. The NJBPU awarded ACE electric revenue requirement increases of $36 million and $9 million effective December 1, 2023 and February 1, 2024, respectively.

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
DPL - Delaware[(a)]	September 20, 2024 (amended February 28, 2025)	Natural Gas	$ 42	10.65%	First quarter of 2026
ACE - New Jersey[(b)]	November 21, 2024	Electric	109	10.70%	Fourth quarter of 2025

(a) DPL implemented interim rates on April 20, 2025, subject to refund. Interim rates are not to exceed 10% of interstate operating revenues.

(b) Requested increases are before New Jersey sales and use tax. ACE intends to put rates into effect on August 21, 2025, subject to refund.

Transmission Formula Rates

(Dollars in millions, except per share data, unless otherwise noted)

The Utility Registrants' transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15, and PECO is required to file on or before May 31, with the resulting rates effective on June 1 of the same year. The annual update for BGE is based on prior year actual costs and current year projected capital additions, accumulated depreciation, depreciation and amortization expense, and accumulated deferred income taxes. The update for BGE also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2025, the following increase was included in the Utility Registrant's electric transmission formula rate update:

Registrant [(a)]	Initial Revenue Requirement Increase	Annual Reconciliation Increase	Total Revenue Requirement Increase [(b)]	Allowed Return on Rate Base [(c)]	Allowed ROE [(d)]
BGE	$ 21	$ 21	$ 35 (e)	7.53 %	10.50 %

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(a) All rates are effective June 1, 2025 - May 31, 2026, subject to review by interested parties pursuant to review protocols of BGE's tariffs.
(b) While the transmission filing reflects the tax benefit of NOLCs, the impacts of the NOLCs will not be reflected in the financial statements until the PLR is received from the IRS. See Note 6 — Income Taxes for additional information on NOLCs.
(c) Represents the weighted average debt and equity return on transmission rate base.
(d) The rate of return on common equity for BGE includes a 50-basis-point incentive adder for being a member of an RTO.
(e) The increase in BGE's transmission revenue requirement includes a $7 million reduction related to a FERC-approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.

Other State Regulatory Matters

Illinois Regulatory Matters

CEJA (Exelon and ComEd). On September 15, 2021, the Governor of Illinois signed into law CEJA. CEJA includes, among other features, (1) procurement of CMCs from qualifying nuclear-powered generating facilities, (2) a requirement to file a general rate case or a new four-year MRP no later than January 20, 2023 to establish rates effective after ComEd's existing performance-based distribution formula rate sunsets, (3) requirements that ComEd and the ICC initiate and conduct various regulatory proceedings on subjects including ethics, spending, grid investments, and performance metrics.

ComEd Electric Distribution Rates

Beginning in 2024, ComEd recovers from retail customers, subject to certain exceptions, the costs it incurs to provide electric delivery services either through its electric distribution rate or other recovery mechanisms authorized by CEJA. On January 17, 2023, ComEd filed a petition with the ICC seeking approval of a MRP for 2024-2027. The MRP supports a multi-year grid plan (Grid Plan), also filed on January 17, covering planned investments on the electric distribution system within ComEd's service area through 2027. Costs incurred during each year of the MRP are subject to ICC review and the plan's revenue requirement for each year will be reconciled with the actual costs that the ICC determines are prudently and reasonably incurred for that year. The reconciliation is subject to adjustment for certain costs, including a limitation on recovery of costs that are more than 105% of certain costs in the previously approved MRP revenue requirement, absent a modification of the rate plan itself. Thus, for example, the rate adjustments necessary to reconcile 2024 revenues to ComEd's actual 2024 costs incurred would take effect in January 2026 after the ICC's review during 2025.

On December 14, 2023, the ICC issued a final order. The ICC rejected ComEd's Grid Plan as non-compliant with certain requirements of CEJA and required ComEd to file a revised Grid Plan. In the absence of an approved Grid Plan, the ICC set ComEd's forecast revenue requirements for 2024-2027 based on ComEd's approved year-end 2022 rate base. This resulted in a total cumulative revenue requirement increase of $501 million, a $986 million total revenue reduction from the requested cumulative revenue requirement increase but remained subject to annual reconciliation in accordance with CEJA. The final order approved the process and formulas associated with the MRP reconciliation mechanisms. The ICC's December 2023 order also denied ComEd's ability to earn a return on its pension asset.

On December 22, 2023, ComEd filed an application for rehearing on several findings in the final order including the use of the 2022 year-end rate base to establish forecast revenue requirements for 2024-2027, ROE, pension asset return, and capital structure. On January 10, 2024, ComEd's application for rehearing was denied on all issues except for the order's use of the 2022 year-end rate base. On April 18, 2024, the ICC issued its final order on rehearing, which approved the use of the forecasted year-end 2023 rate base that resulted in increased revenue requirements for 2024-2027. These revenue requirements determined during the rehearing process established base revenue requirements until the ICC approved the Refiled Grid Plan on December 19, 2024.

On January 10, 2024, ComEd filed an appeal in the Illinois Appellate Court of the issues on which rehearing was denied, including but not limited to the allowed ROE, 50 % equity ratio, and denial of a return on ComEd's pension asset. There is no deadline by when the appellate court must rule. On March 13, 2024, ComEd filed its Refiled Grid Plan with supporting testimony and schedules with the ICC and subsequently on March 15, 2024, ComEd also filed a petition to adjust its MRP to authorize increased rates consistent with the Refiled Grid Plan. On December 19, 2024, the ICC approved the Refiled Grid Plan and adjusted the approved MRP with rates effective on January 1, 2025. The final approved MRP, as adjusted, which reflects the Refiled Grid Plan, resulted in a total cumulative revenue requirement increase of $1.045 billion over the 2024-2027 plan years and remains subject to annual reconciliations in accordance with CEJA. ComEd filed timely requests for rehearing and an appeal of the MRP order, again limited to the issues on which rehearing of the December 2023 order was denied, including the allowed ROE, 50 % equity ratio, and denial of a return on ComEd's pension asset.

In January 2022, ComEd filed a request with the ICC proposing performance metrics that would be used in determining ROE incentives and penalties in the event ComEd filed a MRP in January 2023. On September 27, 2022, the ICC issued a final order approving seven performance metrics that provide symmetrical performance adjustments of 32 total basis points to ComEd's rate of return on common equity based on the extent to which ComEd achieves the annual performance goals. On November 10, 2022, the ICC granted ComEd's application for rehearing, in part. On April 5, 2023, the ICC issued its final order on rehearing for the performance and tracking metrics proceeding, in which the ICC declined to adopt ComEd's proposed modifications to the reliability and peak load reduction performance metrics.

Carbon Mitigation Credit

CEJA establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. ComEd is required to purchase CMCs from participating nuclear power generating facilities between June 1, 2022 and May 31, 2027. The price to be paid for each CMC was established through a competitive bidding process that included consumer-protection measures that capped the maximum acceptable bid amount and a formula that reduces CMC prices by an energy price index, the base residual auction capacity price in the ComEd zone of PJM, and the monetized value of any federal tax credit or other subsidy if applicable. The seller has not provided notification to ComEd or the IPA that any subsidies or tax credits, such as nuclear production tax credits that became available for electricity generated beginning January 1, 2024, have been monetized and the IPA did not adjust the CMC price paid by ComEd in 2024 . The consumer protection measures contained in CEJA will result in net payments to ComEd ratepayers if the energy index, the capacity price and applicable federal tax credits or subsidy exceed the CMC contract price. Beginning with the June 2022 monthly billing period, ComEd began issuing credits and/or charges to its retail customers under its CMC rider, the Rider Carbon-Free Resource Adjustment (Rider CFRA). A regulatory asset is recorded for the difference between ComEd's costs associated with the procurement of CMCs from participating nuclear power generating facilities and revenues received from customers. The balance as of March 31, 2025 is $17 million .

Energy Efficiency

CEJA extends ComEd's current cumulative annual energy efficiency MWh savings goals through 2040, adds expanded electrification measures to those goals, increases low-income commitments, and adds a new performance adjustment to the energy efficiency formula rate. ComEd expects its annual spend to increase in 2023 through 2040 to achieve these energy efficiency MWh savings goals, which is deferred as a separate regulatory asset that is recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures.

Other Federal Regulatory Matters

(Dollars in millions, except per share data, unless otherwise noted)

FERC Audit (Exelon and ComEd). The Utility Registrants are subject to periodic audits and investigations by FERC. FERC's Division of Audits and Accounting initiated a nonpublic audit of ComEd in April 2021 evaluating ComEd's compliance with (1) approved terms, rates and conditions of its federally regulated service; (2) accounting requirements of the Uniform System of Accounts; (3) reporting requirements of the FERC Form 1; and (4) the requirements for record retention. The audit period extended back to January 1, 2017.

On July 27, 2023, FERC published a final audit report which included, among other things, findings and recommendations related to ComEd's methodology regarding the allocation of certain overhead costs to capitalized construction costs under FERC regulations, including a suggestion that refunds may be due to customers for amounts collected in previous years. ComEd responded to that report and on August 28, 2023, ComEd filed a formal notice of the issues it contested within the audit report. On December 14, 2023, FERC appointed a settlement judge for the contested overhead allocation findings and set the matter for a trial-type hearing. That hearing process was held in abeyance while a formal settlement process, which began in February 2024, took place.

On July 30, 2024, ComEd reached an agreement in principle on the contested overhead allocation finding. As a result of the settlement process, ComEd recorded a charge for the probable disallowance of $70 million of certain currently capitalized construction costs to operating expenses, which are not expected to be recovered in future rates. The existing loss estimate was reflected in Exelon and ComEd's financial statements as of December 31, 2024. ComEd and FERC staff jointly filed the settlement agreement with FERC for approval on February 11, 2025. The settlement was approved by FERC on April 4, 2025.

Regulatory Assets and Liabilities

The Utility Registrants' regulatory assets and liabilities have not changed materially since December 31, 2024, unless noted below. See Note 3 — Regulatory Matters of the 2024 Form 10-K for additional information on the specific regulatory assets and liabilities.

PECO. Regulatory assets increased $61 million primarily due to an increase of $71 million in the Deferred Income Taxes regulatory asset. Regulatory liabilities increased $93 million primarily due to an increase of $64 million in the Decommissioning the Regulatory Agreement Units and an increase of $32 million in the Electric energy and natural gas costs regulatory liabilities.

ACE. Regulatory liabilities increased $10 million primarily due to an increase of $8 million in the Transmission formula rate annual reconciliations regulatory liability.

Capitalized Ratemaking Amounts Not Recognized

The following table presents authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes in the Registrants' Consolidated Balance Sheets. These amounts will be recognized as revenues in the related Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to the Utility Registrants' customers. PECO had no related amounts at March 31, 2025 and December 31, 2024.

	Exelon	ComEd [(a)]	BGE [(b)]	PHI	Pepco [(c)]	DPL [(d)]	ACE [(e)]
March 31, 2025	$ 87	$ 38	$ 9	$ 40	$ 24	$ 1	$ 15
December 31, 2024	117	46	16	55	40	1	14

(a) Reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its electric distribution rates and formula rates regulatory assets.
(b) BGE's amount capitalized for ratemaking purposes primarily relates to earnings on shareholders' investment on AMI programs and investments in rate base included in the multi-year plan reconciliations.
(c) Pepco's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on AMI programs, Energy efficiency and demand response programs, investments in rate base and revenues included in the multi-year plan reconciliations, and a portion of Pepco District of Columbia's revenue decoupling.
(d) DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on AMI programs and Energy efficiency and demand response programs.
(e) ACE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on AMI programs.

(Dollars in millions, except per share data, unless otherwise noted)

3. Revenue from Contracts with Customers (All Registrants)

The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that the entities expect to be entitled to in exchange for those goods or services. The primary sources of revenue include regulated electric and gas tariff sales, distribution, and transmission services.

See Note 4 — Revenue from Contracts with Customers of the 2024 Form 10-K for additional information regarding the primary sources of revenue for the Registrants.

Contract Liabilities

The Registrants record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. The Registrants record contract liabilities in Other current liabilities and Other noncurrent deferred credits and other liabilities in their Consolidated Balance Sheets.

For Pepco, DPL, and ACE these contract liabilities primarily relate to upfront consideration received in the third quarter of 2020 for a collaborative arrangement ("Agreement") with an unrelated owner and manager of communication infrastructure, as well as additional consideration received for the payment option amendment ("Amendment") executed during the fourth quarter of 2023, which is discussed in further detail within Note 4 — Revenue from Contracts with Customers of the 2024 Form 10-K. The contract liability balance attributable to the Agreement and the Amendment is being recognized as Electric operating revenues over a 35 year period and 31 year period, respectively.

The following table provides a rollforward of the contract liabilities reflected in Exelon's, PHI's, Pepco's, DPL's, and ACE's Consolidated Balance Sheets for the three months ended March 31, 2025 and 2024. At March 31, 2025 and December 31, 2024, ComEd's, PECO's, and BGE's contract liabilities were immaterial.

	Exelon [(a)]	PHI [(a)]	Pepco [(a)]	DPL	ACE
Balance at December 31, 2024	$ 127	$ 127	$ 101	$ 13	$ 13
Revenues recognized	(1)	(1)	(1)	—	—
Balance at March 31, 2025	$ 126	$ 126	$ 100	$ 13	$ 13

	Exelon [(a)]	PHI [(a)]	Pepco [(a)]	DPL	ACE
Balance at December 31, 2023	$ 133	$ 133	$ 107	$ 13	$ 13
Revenues recognized	(2)	(2)	(2)	—	—
Balance at March 31, 2024	$ 131	$ 131	$ 105	$ 13	$ 13

(a) Revenues recognized in the three months ended March 31, 2025 and 2024, were included in the contract liabilities at December 31, 2024 and 2023, respectively.

Transaction Price Allocated to Remaining Performance Obligations

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of March 31, 2025. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years.

This disclosure excludes the Utility Registrants' gas and electric tariff sales contracts and transmission revenue contracts as they generally have an original expected duration of one year or less and, therefore, do not contain any future, unsatisfied performance obligations to be included in this disclosure.

(Dollars in millions, except per share data, unless otherwise noted)

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Year	Exelon	PHI	Pepco	DPL	ACE
2025	$ 4	$ 4	$ 4	$ —	$ —
2026	6	6	5	1	—
2027	5	5	5	—	—
2028	5	5	5	—	—
2029 and thereafter	106	106	81	12	13
Total	$ 126	$ 126	$ 100	$ 13	$ 13

Revenue Disaggregation

The Registrants disaggregate revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 4 — Segment Information for the presentation of the Registrants' revenue disaggregation.

4. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the CODMs in deciding how to evaluate performance and allocate resources at each of the Registrants. The Chief Executive Officer is the CODM for Exelon. For PHI and each of the Utility Registrants, CODM responsibilities are shared by Exelon's Chief Operating Officer and the Utility Registrant's Chief Executive Officer.

Exelon has six reportable segments, which include ComEd, PECO, BGE, and PHI's three reportable segments consisting of Pepco, DPL, and ACE. ComEd, PECO, BGE, Pepco, DPL, and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE's CODMs rely on a variety of business considerations, including net income, in evaluating segment performance, determining reinvestment of profits, and establishing the amounts of dividend distributions.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three months ended March 31, 2025 and 2024 is as follows:

	ComEd	PECO	BGE	PHI	Other [a]	Intersegment Eliminations	Exelon
Operating revenues [b]:							
2025							
Electric revenues	$ 2,065	$ 956	$ 1,012	$ 1,687	$ —	$ (11)	$ 5,709
Natural gas revenues	—	377	542	88	—	(2)	1,005
Shared service and other revenues	—	—	—	3	466	(469)	—
Total operating revenues	$ 2,065	$ 1,333	$ 1,554	$ 1,778	$ 466	$ (482)	$ 6,714
2024							
Electric revenues	$ 2,095	$ 782	$ 881	$ 1,532	$ —	$ (6)	$ 5,284
Natural gas revenues	—	272	416	72	—	(1)	759
Shared service and other revenues	—	—	—	2	459	(461)	—
Total operating revenues	$ 2,095	$ 1,054	$ 1,297	$ 1,606	$ 459	$ (468)	$ 6,043
Less:							
Purchased power							
2025	$ 689	$ 361	$ 450	$ 684	$ —	$ —	$ 2,184
2024	907	306	377	607	—	—	2,197
Purchased fuel							
2025	$ —	$ 141	$ 159	$ 38	$ —	$ —	$ 338

(Dollars in millions, except per share data, unless otherwise noted)

2024	—	97	87	29	—	—	213

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	ComEd	PECO	BGE	PHI	Other [a]	Intersegment Eliminations	Exelon
Operating and maintenance							
2025	$ 323	$ 266	$ 242	$ 296	$ 429	$ (209)	$ 1,347
2024	318	235	205	274	438	(199)	1,271
Operating and maintenance from affiliates							
2025	$ 100	$ 61	$ 63	$ 53	$ 11	$ (288)	$ —
2024	100	58	59	51	9	(277)	—
Depreciation and amortization							
2025	$ 380	$ 109	$ 164	$ 234	$ 16	$ —	$ 903
2024	362	104	150	246	17	—	879
Taxes other than income taxes							
2025	$ 99	$ 60	$ 96	$ 140	$ 10	$ —	$ 405
2024	94	51	89	128	9	—	371
(Gain) loss on sale of assets							
2025	$ —	$ —	$ —	$ 1	$ —	$ —	$ 1
2024	—	(2)	—	—	—	—	(2)
Interest expense, net[c]							
2025	$ 125	$ 59	$ 58	$ 99	$ 163	$ —	$ 504
2024	119	52	50	90	151	—	462
Interest expense from affiliates, net[c]							
2025	$ 3	$ 4	$ —	$ 1	$ (1)	$ (1)	$ 6
2024	3	3	—	—	—	—	6
Other, net							
2025	$ (21)	$ (8)	$ (9)	$ (19)	$ (11)	$ 16	$ (52)
2024	(20)	(9)	(8)	(27)	(19)	8	(75)
Income taxes							
2025	$ 65	$ 14	$ 71	$ 57	$ (37)	$ —	$ 170
2024	19	10	24	40	(30)	—	63
Net income (loss) attributable to common shareholders							
2025	$ 302	$ 266	$ 260	$ 194	$ (114)	$ —	$ 908
2024	193	149	264	168	(116)	—	658
Supplemental segment information							
Intersegment revenues[d]							
2025	$ 8	$ 3	$ 2	$ 2	$ 463	$ (478)	$ —
2024	2	2	2	3	457	(466)	—
Capital expenditures							
2025	$ 590	$ 424	$ 406	$ 513	$ 13	$ —	$ 1,946
2024	594	361	324	453	35	—	1,767
Total assets							
March 31, 2025	$45,199	$17,789	$15,677	$28,349	$ 6,530	$ (4,060)	$109,484
December 31, 2024	44,750	17,123	15,542	28,297	6,012	(3,940)	107,784

(Dollars in millions, except per share data, unless otherwise noted)

(a) Other primarily includes Exelon's corporate operations, shared service entities, and other financing and investment activities
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in Taxes other than income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 14 — Supplemental Financial Information for additional information on total utility taxes.

(c) Interest expense, net and Interest expense to affiliates, net are primarily inclusive of Interest expense, which is partially offset by an immaterial amount of Interest income.
(d) See Note 15 — Related Party Transactions for additional information on intersegment revenues.

PHI:

	Pepco	DPL	ACE	Other [(a)]	Intersegment Eliminations	PHI
Operating revenues [(b)]:						
2025						
Electric revenues	$ 859	$ 460	$ 373	$ —	$ (5)	$ 1,687
Natural gas revenues	—	88	—	—	—	88
Shared service and other revenues	—	—	—	106	(103)	3
Total operating revenues	$ 859	$ 548	$ 373	$ 106	$ (108)	$ 1,778
2024						
Electric revenues	$ 759	$ 419	$ 358	$ —	$ (4)	$ 1,532
Natural gas revenues	—	72	—	—	—	72
Shared service and other revenues	—	—	—	109	(107)	2
Total operating revenues	$ 759	$ 491	$ 358	$ 109	$ (111)	$ 1,606
Less:						
Purchased power						
2025	$ 318	$ 209	$ 157	$ —	$ —	$ 684
2024	281	186	140	—	—	607
Purchased fuel						
2025	$ —	$ 38	$ —	$ —	$ —	$ 38
2024	—	29	—	—	—	29
Operating and maintenance						
2025	$ 96	$ 60	$ 51	$ 89	$ —	$ 296
2024	86	51	47	90	—	274
Operating and maintenance from affiliates						
2025	$ 63	$ 46	$ 39	$ 13	$ (108)	$ 53
2024	64	44	40	14	(111)	51
Depreciation and amortization						
2025	$ 105	$ 63	$ 64	$ 2	$ —	$ 234
2024	107	61	74	4	—	246
Taxes other than income taxes						
2025	$ 113	$ 21	$ 2	$ 4	$ —	$ 140
2024	102	20	2	4	—	128
Loss on sale of assets						
2025	$ 1	$ —	$ —	$ —	$ —	$ 1
2024	—	—	—	—	—	—
Interest expense, net[(c)]						
2025	$ 52	$ 25	$ 21	$ 1	$ —	$ 99

(Dollars in millions, except per share data, unless otherwise noted)

2024	45	22	20	3	—	90
Interest expense to affiliates, net[c]						
2025	$ —	$ —	$ —	$ 1	$ —	$ 1
2024	—	—	—	—	—	—
Other, net						
2025	$ (11)	$ (4)	$ (3)	$ (1)	$ —	$ (19)
2024	(15)	(5)	(5)	(2)	—	(27)

Income taxes						
2025	$ 25	$ 21	$ 11	$ —	$ —	$ 57
2024	14	17	11	(2)	—	40
Net income (loss) attributable to common shareholders						
2025	$ 97	$ 69	$ 31	$ (3)	$ —	$ 194
2024	75	66	29	(2)	—	168
Supplemental segment information						
Intersegment revenues[d]						
2025	$ 2	$ 2	$ 1	$ 106	$ (109)	$ 2
2024	2	2	1	109	(111)	3
Capital expenditures						
2025	$ 240	$ 156	$ 105	$ 12	$ —	$ 513
2024	229	134	89	1	—	453
Total assets						
March 31, 2025	$ 12,011	$ 6,484	$ 5,387	$ 4,521	$ (54)	$ 28,349
December 31, 2024	12,000	6,421	5,349	4,567	(40)	28,297

(a) Other primarily includes PHI's corporate operations, shared service entities, and other financing and investment activities.
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in Taxes other than income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 14 — Supplemental Financial Information for additional information on total utility taxes.
(c) Interest expense, net and interest expense to affiliates, net are primarily inclusive of Interest expense, which is partially offset by an immaterial amount of Interest income.
(d) Includes intersegment revenues with ComEd, PECO, and BGE, which are eliminated at Exelon.

Electric and Gas Revenue by Customer Class (Utility Registrants):

The following tables disaggregate the Registrants' revenues recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of electric sales and natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with the Utility Registrants, but exclude any intercompany revenues.

(Dollars in millions, except per share data, unless otherwise noted)

	Three Months Ended March 31, 2025						
Revenues from contracts with customers	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Electric revenues							
Residential	$ 993	$ 631	$ 648	$ 918	$ 424	$ 298	$ 196
Small commercial & industrial	600	162	109	169	51	64	54
Large commercial & industrial	296	84	144	367	289	28	50
Public authorities & electric railroads	17	8	8	17	8	4	5
Other[(a)]	236	76	113	223	86	71	68
Total electric revenues[(b)]	$ 2,142	$ 961	$ 1,022	$ 1,694	$ 858	$ 465	$ 373
Natural gas revenues							
Residential	$ —	$ 267	$ 378	$ 56	$ —	$ 56	$ —
Small commercial & industrial	—	86	63	21	—	21	—
Large commercial & industrial	—	—	96	3	—	3	—
Transportation	—	13	—	5	—	5	—
Other[(c)]	—	10	24	3	—	3	—
Total natural gas revenues[(d)]	$ —	$ 376	$ 561	$ 88	$ —	$ 88	$ —
Total revenues from contracts with customers	$ 2,142	$ 1,337	$ 1,583	$ 1,782	$ 858	$ 553	$ 373
Other revenues							
Revenues from alternative revenue programs	$ (85)	$ (9)	$ (29)	$ (3)	$ 2	$ (5)	$ —
Other electric revenues[(e)]	8	4	—	(1)	(1)	—	—
Other natural gas revenues[(e)]	—	1	—	—	—	—	—
Total other revenues	$ (77)	$ (4)	$ (29)	$ (4)	$ 1	$ (5)	$ —
Total revenues for reportable segments	$ 2,065	$ 1,333	$ 1,554	$ 1,778	$ 859	$ 548	$ 373

(Dollars in millions, except per share data, unless otherwise noted)

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	Three Months Ended March 31, 2024						
Revenues from contracts with customers	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Electric revenues							
Residential	$ 918	$ 520	$ 534	$ 775	$ 345	$ 256	$ 174
Small commercial & industrial	594	126	90	158	46	62	50
Large commercial & industrial	320	57	132	340	262	29	49
Public authorities & electric railroads	17	7	7	20	11	4	5
Other[(a)]	227	74	93	192	64	63	67
Total electric revenues[(b)]	$ 2,076	$ 784	$ 856	$ 1,485	$ 728	$ 414	$ 345
Natural gas revenues							
Residential	$ —	$ 193	$ 271	$ 46	$ —	$ 46	$ —
Small commercial & industrial	—	64	47	17	—	17	—
Large commercial & industrial	—	—	72	2	—	2	—
Transportation	—	8	—	5	—	5	—
Other[(c)]	—	7	5	2	—	2	—
Total natural gas revenues[(d)]	$ —	$ 272	$ 395	$ 72	$ —	$ 72	$ —
Total revenues from contracts with customers	$ 2,076	$ 1,056	$ 1,251	$ 1,557	$ 728	$ 486	$ 345
Other revenues							
Revenues from alternative revenue programs	$ 19	$ (2)	$ 43	$ 46	$ 29	$ 4	$ 13
Other electric revenues[(e)]	—	—	2	3	2	1	—
Other natural gas revenues[(e)]	—	—	1	—	—	—	—
Total other revenues	$ 19	$ (2)	$ 46	$ 49	$ 31	$ 5	$ 13
Total revenues for reportable segments	$ 2,095	$ 1,054	$ 1,297	$ 1,606	$ 759	$ 491	$ 358

(a) Includes transmission revenue from PJM, wholesale electric revenue, and mutual assistance revenue.
(b) Includes operating revenues from affiliates in 2025 and 2024 respectively of:
- $8 million, $2 million at ComEd
- $2 million, $2 million at PECO
- $1 million, $1 million at BGE
- $2 million, $3 million at PHI
- $2 million, $2 million at Pepco

(Dollars in millions, except per share data, unless otherwise noted)

- $2 million, $2 million at DPL
- $1 million, $1 million at ACE

(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates in 2025 and 2024 respectively of:
- $1 million, less than $1 million at PECO
- $1 million, $1 million at BGE

(e) Includes late payment charge revenues.

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5. Accounts Receivable (All Registrants)

Allowance for Credit Losses on Accounts Receivable

The following tables present the rollforward of Allowance for Credit Losses on Customer Accounts Receivable.

	Three Months Ended March 31, 2025							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2024	$ 406	$ 109	$ 133	$ 56	$ 108	$ 59	$ 17	$ 32
Plus: Current period provision for expected credit losses[(a)]	133	33	41	23	36	17	10	9
Less: Write-offs[(b)], net of recoveries[(c)]	53	17	14	7	15	7	4	4
Balance at March 31, 2025	$ 486	$ 125	$ 160	$ 72	$ 129	$ 69	$ 23	$ 37

	Three Months Ended March 31, 2024							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2023	$ 317	$ 69	$ 95	$ 46	$ 107	$ 52	$ 19	$ 36
Plus: Current period provision for expected credit losses	79	22	23	15	19	12	3	4
Less: Write-offs, net of recoveries	50	9	11	9	21	12	5	4
Balance at March 31, 2024	$ 346	$ 82	$ 107	$ 52	$ 105	$ 52	$ 17	$ 36

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(a) For ComEd, PECO, BGE, Pepco, DPL, and ACE, the increase is primarily a result of increased receivable balances.
(b) For Pepco, the decrease is primarily attributable to favorable customer payment behavior.
(c) Recoveries were not material to the Registrants.

The following tables present the rollforward of Allowance for Credit Losses on Other Accounts Receivable.

	Three Months Ended March 31, 2025							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2024	$ 107	$ 34	$ 18	$ 6	$ 49	$ 27	$ 9	$ 13
Plus: Current period provision for								

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
expected credit losses[a]	15	2	9	1	3	—	—	3
Less: Write-offs[b], net of recoveries[c]	9	2	5	1	1	—	—	1
Balance at March 31, 2025	$ 113	$ 34	$ 22	$ 6	$ 51	$ 27	$ 9	$ 15

	Three Months Ended March 31, 2024							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2023	$ 82	$ 17	$ 8	$ 7	$ 50	$ 28	$ 8	$ 14
Plus: Current period provision for expected credit losses	18	3	5	2	8	7	—	1
Less: Write-offs, net of recoveries	4	1	—	2	1	—	—	1
Balance at March 31, 2024	$ 96	$ 19	$ 13	$ 7	$ 57	$ 35	$ 8	$ 14

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(a) For Pepco, the decrease is primarily a result of changes in customer risk profile.
(b) For PECO, the increase is primarily a result of increased terminations.
(c) Recoveries were not material to the Registrants.

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Unbilled Customer Revenue

The following table provides additional information about unbilled customer revenues recorded in the Registrants' Consolidated Balance Sheets as of March 31, 2025 and December 31, 2024.

	Unbilled customer revenues[a]							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
March 31, 2025	$ 961	$ 366	$ 235	$ 171	$ 189	$ 95	$ 51	$ 43
December 31, 2024	1,114	335	254	257	268	121	76	71

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(a) Unbilled customer revenues are classified in Customer accounts receivable, net in the Registrants' Consolidated Balance Sheets.

Other Purchases of Customer and Other Accounts Receivables

For the three months ended March 31, 2025 and 2024, the Utility Registrants were required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia, Delaware, and New Jersey, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participated in the utilities' consolidated billing. The following table presents the total receivables purchased.

	Total receivables purchased							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three months ended March 31, 2025	$1,138	$ 253	$ 334	$ 225	$ 326	$ 201	$ 68	$ 57
Three months ended March 31, 2024	1,060	235	297	219	309	194	60	55

(Dollars in millions, except per share data, unless otherwise noted)

6. Income Taxes (All Registrants)

Rate Reconciliation

The effective income tax rate from continuing operations varies from the U.S. federal statutory rate principally due to the following:

	Three Months Ended March 31, 2025 [a]							
	Exelon	ComEd [b]	PECO [c]	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State income taxes, net of federal income tax benefit	5.1	7.6	(3.5)	6.2	6.5	6.4	6.4	7.0
Plant basis differences	(3.8)	(1.0)	(11.1)	(1.5)	(0.7)	(1.0)	(0.5)	(0.3)
Excess deferred tax amortization	(6.5)	(9.4)	(1.6)	(4.1)	(3.9)	(5.3)	(3.3)	(1.4)
Amortization of investment tax credit, including deferred taxes on basis difference	—	(0.1)	—	—	—	—	(0.1)	(0.1)
Tax credits	(0.5)	(0.7)	—	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Other	0.5	0.3	0.2	0.2	0.1	(0.3)	0.1	0.3
Effective income tax rate	15.8 %	17.7 %	5.0 %	21.5 %	22.7 %	20.5 %	23.3 %	26.2 %

	Three Months Ended March 31, 2024 [a]							
	Exelon	ComEd [d]	PECO [c]	BGE [d]	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %

(Dollars in millions, except per share data, unless otherwise noted)

Increase (decrease) due to:								
State income taxes, net of federal income tax benefit	6.4	7.8	(0.6)	6.3	6.4	6.2	6.2	7.1
Plant basis differences	(3.8)	(0.9)	(12.2)	(1.2)	(0.9)	(1.3)	(1.1)	0.1
Excess deferred tax amortization	(14.7)	(18.9)	(2.3)	(17.5)	(6.8)	(9.9)	(5.4)	(1.3)
Amortization of investment tax credit, including deferred taxes on basis difference	(0.1)	(0.1)	—	—	(0.1)	—	(0.1)	(0.1)
Tax credits	(0.4)	(0.3)	—	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)
Other	0.3	0.4	0.4	0.1	(0.1)	—	0.2	1.0
Effective income tax rate	8.7 %	9.0 %	6.3 %	8.3 %	19.2 %	15.7 %	20.5 %	27.5 %

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(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
(b) For ComEd, the lower effective tax rate is primarily due to CEJA which resulted in the acceleration of certain income tax benefits.
(c) For PECO, the lower effective tax rate is primarily related to plant basis differences attributable to tax repair deductions.
(d) For ComEd, the lower effective tax rate is primarily due to CEJA which resulted in the acceleration of certain income tax benefits. For BGE, the lower effective tax rate is primarily due to the Maryland multi-year plan which resulted in the acceleration of certain income tax benefits.

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Unrecognized Tax Benefits

Exelon, PHI and DPL have the following unrecognized tax benefits at March 31, 2025 and December 31, 2024. ComEd's, PECO's, BGE's, Pepco's, and ACE's amounts are not material.

	Exelon [(a)]	PHI	DPL
March 31, 2025	$ 100	$ 51	$ 15
December 31, 2024	96	48	12

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(a) At March 31, 2025 and December 31, 2024, Exelon's unrecognized tax benefits is inclusive of $31 million related to Constellation's share of unrecognized tax benefits for periods prior to the separation. Exelon reflected an offsetting receivable of $31 million in Other deferred debits and other assets in the Consolidated Balance Sheet for these amounts.

Other Tax Matters

Tax Matters Agreement (Exelon)

In connection with the separation, Exelon entered into a TMA with Constellation. The TMA governs the respective rights, responsibilities, and obligations between Exelon and Constellation after the separation with respect to tax liabilities, refunds and attributes for open tax years that Constellation was part of Exelon’s consolidated group for U.S. federal, state, and local tax purposes.

Indemnification for Taxes. As a former subsidiary of Exelon, Constellation has joint and several liability with Exelon to the IRS and certain state jurisdictions relating to the taxable periods prior to the separation. The TMA specifies that Constellation is liable for their share of taxes required to be paid by Exelon with respect to taxable periods prior to the separation to the extent Constellation would have been responsible for such taxes under the existing Exelon tax sharing agreement. At March 31, 2025, there is no balance due to or from Constellation.

Tax Refunds. The TMA specifies that Constellation is entitled to their share of any future tax refunds claimed by Exelon with respect to taxable periods prior to the separation to the extent that Constellation would have received such tax refunds under the existing Exelon tax sharing agreement. At March 31, 2025, there is no balance due to or from Constellation.

Tax Attributes. At the date of separation certain tax attributes, primarily pre-closing tax credit carryforwards, that were generated by Constellation were required by law to be allocated to Exelon. The TMA also provides that Exelon will reimburse Constellation when those allocated tax attribute carryforwards are utilized. At March 31, 2025, Exelon recorded a payable of $141 million and $198 million in Other current liabilities and Other deferred credits and other liabilities, respectively, in the Consolidated Balance Sheet for tax attribute carryforwards that are expected to be utilized and reimbursed to Constellation.

Corporate Alternative Minimum Tax (All Registrants)

On August 16, 2022, the IRA was signed into law and implements a new corporate alternative minimum tax (CAMT) that imposes a 15.0% tax on modified GAAP net income. Corporations are entitled to a tax credit (minimum tax credit) to the extent the CAMT liability exceeds the regular tax liability. This amount can be carried forward indefinitely and used in future years when regular tax exceeds the CAMT.

Beginning in 2023, based on the existing statute, Exelon and each of the Utility Registrants will be subject to and will report the CAMT on a separate Registrant basis in the Consolidated Statements of Operations and Comprehensive Income and the Consolidated Balance Sheets. The deferred tax asset related to the minimum tax credit carryforward will be realized to the extent Exelon's consolidated deferred tax liabilities exceed the minimum tax credit carryforward. Exelon's deferred tax liabilities are expected to exceed the minimum tax credit carryforward for the foreseeable future and thus no valuation allowance is required.

On September 12, 2024, the U.S. Treasury issued proposed regulations providing further guidance addressing the implementation of CAMT. The proposed regulations are consistent with Exelon's prior interpretation and therefore there are no financial statement impacts. Exelon will continue to monitor and assess the potential financial statement impacts of final regulations or other guidance when issued.

Allocation of Income Taxes to Regulated Utilities (All Registrants)

In Q2 2024, the IRS issued a series of PLRs, to another taxpayer, providing guidance with respect to the application of the tax normalization rules to the allocation of consolidated tax benefits among the members of a consolidated group associated with NOLC for ratemaking purposes. The rulings provide that for ratemaking purposes the tax benefit of NOLC should be reflected on a separate company basis not taking into consideration the utilization of losses by other affiliates. A PLR issued to another taxpayer may not be relied on as precedent.

For the Utility Registrants, except for PECO, the methodology prescribed by the IRS in these PLRs could result in a material reduction of the regulatory liability established for EDITs arising from the TCJA corporate tax rate change that are being amortized and flowed through to customers as well as a reduction in the accumulated deferred income taxes included in rate base for ratemaking purposes. The Utility Registrants, except for PECO, filed PLR requests with the IRS confirming the treatment of the NOLC for ratemaking purposes. The Utility Registrants will record the impact, if any, upon receiving the PLR from the IRS.

7. Retirement Benefits (All Registrants)

Defined Benefit Pension and OPEB

(Dollars in millions, except per share data, unless otherwise noted)

The majority of the 2025 pension benefit cost for the Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 5.68%. The majority of the 2025 OPEB cost is calculated using an expected long-term rate of return on plan assets of 6.50% for funded plans and a discount rate of 5.64%.

During the first quarter of 2025, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2025. This valuation resulted in an increase to the pension obligation of $1 million and an increase to the OPEB obligation and asset of $6 million and $2 million, respectively. Additionally, AOCI decreased by $5 million (after-tax) and regulatory assets increased by $8 million and liabilities decreased by $3 million.

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to capitalization, for the three months ended March 31, 2025 and 2024.

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2025	2024	2025	2024
Components of net periodic benefit cost				
Service cost	$ 38	$ 42	$ 6	$ 7
Interest cost	146	141	25	24
Expected return on assets	(178)	(184)	(21)	(21)
Amortization of:				
Prior service cost (credit)	1	1	(2)	(2)
Actuarial loss	53	53	—	—
Net periodic benefit cost	$ 60	$ 53	$ 8	$ 8

The amounts below represent the Registrants' allocated pension and OPEB costs. For Exelon, the service cost component is included in Operating and maintenance expense and Property, plant, and equipment, net while the non-service cost components are included in Other, net and Regulatory assets. For PHI and each of the Utility Registrants, which apply multi-employer accounting, the service cost and non-service cost components are included in Operating and maintenance expense and Property, plant, and equipment, net in their consolidated financial statements.

	Three Months Ended March 31,	
Pension and OPEB Costs	2025	2024
Exelon	$ 68	$ 61
ComEd	21	17
PECO	2	—
BGE	16	15
PHI	25	23
Pepco	8	9
DPL	4	4
ACE	3	3

Defined Contribution Savings Plan

The Registrants participate in a 401(k) defined contribution savings plan that is sponsored by Exelon. The plan is qualified under applicable sections of the IRC and allows employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the employer contributions and employer matching contributions to the savings plan for the three months ended March 31, 2025 and 2024.

(Dollars in millions, except per share data, unless otherwise noted)

Savings Plan Employer Contributions	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024
Exelon	$ 26	$ 22
ComEd	10	10
PECO	4	3
BGE	3	3
PHI	5	2
Pepco	1	1
DPL	1	1
ACE	1	—

8. Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations. The Registrants do not execute derivatives for speculative or proprietary trading purposes.

Authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include NPNS, cash flow hedges, and fair value hedges. At ComEd, derivative economic hedges related to commodities are recorded at fair value and offset by a corresponding regulatory asset or liability. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivatives settle and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed. At Exelon, derivative hedges that qualify and are designated as cash flow hedges are recorded at fair value and offsets are recorded to AOCI.

Commodity Price Risk

The Utility Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, which are either determined to be non-derivative or classified as economic hedges. The Utility Registrants procure electric and natural gas supply through a competitive procurement process approved by each of the respective state utility commissions. The Utility Registrants' hedging programs are intended to reduce exposure to energy and natural gas price volatility and have no direct earnings impact as the costs are fully recovered from customers through

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regulatory-approved recovery mechanisms. The following table provides a summary of the Utility Registrants' primary derivative hedging instruments, listed by commodity and accounting treatment.

Registrant	Commodity	Accounting Treatment	Hedging Instrument
ComEd	Electricity	NPNS	Fixed price contracts based on all requirements in the IPA procurement plans.
	Electricity	Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability[(a)]	20-year floating-to-fixed energy swap contracts beginning June 2012 based on the renewable energy resource procurement requirements in the Illinois Settlement Legislation of approximately 1.3 million MWhs per year.
PECO	Electricity	NPNS	Fixed price contracts for default supply requirements through full requirements contracts.

	Gas	NPNS	Fixed price contracts to cover about 10% of planned natural gas purchases in support of projected firm sales.
BGE	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed price purchases associated with forecasted gas supply requirements.
Pepco	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
DPL	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed and index priced contracts through full requirements contracts.
	Gas	Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability[(b)]	Exchange traded future contracts for up to 50% of estimated monthly purchase requirements each month, including purchases for storage injections.
ACE	Electricity	NPNS	Fixed price contracts for all BGS requirements through full requirements contracts.

(a) See Note 3 — Regulatory Matters of the 2024 Form 10-K for additional information.
(b) The fair value of the DPL economic hedge is not material at March 31, 2025 and December 31, 2024

The fair value of derivative economic hedges is presented in Other current assets and current and noncurrent Mark-to-market derivative liabilities in Exelon's and ComEd's Consolidated Balance Sheets.

Interest Rate Risk (Exelon)

Exelon Corporate uses a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Exelon Corporate may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. A hypothetical 50 basis point change in the interest rates associated with Exelon's interest rate swaps as of March 31, 2025 would result in an immaterial impact to Exelon's Consolidated Net Income.

Below is a summary of the interest rate hedge balances at March 31, 2025 and December 31, 2024.

	Derivatives Designated as Hedging Instruments	
	March 31, 2025	December 31, 2024
Other current assets	$ —	$ 14
Other deferred debits (noncurrent assets)	4	12

(Dollars in millions, except per share data, unless otherwise noted)

Total derivative assets	4	26
Mark-to-market derivative liabilities (current liabilities)	—	(1)
Mark-to-market derivative liabilities (noncurrent liabilities)	(4)	—
Total mark-to-market derivative liabilities	(4)	(1)
Total mark-to-market derivative net assets	$ —	$ 25

Cash Flow Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as cash flow hedges, the changes in fair value each period are initially recorded in AOCI and reclassified into earnings when the underlying transaction affects earnings.

In February 2025, Exelon terminated the previously issued floating-to-fixed swaps with a total notional of $765 million upon issuance of $1 billion of debt. See Note 9 – Debt and Credit Agreements for additional information on the debt issuance. The settlements resulted in a cash receipt of $16 million. The accumulated AOCI gain of $13 million (net of tax) is being amortized into Interest expense in Exelon's Consolidated Statement of Operations and Comprehensive Income over the 5-year and 10-year terms of the swaps. The following table provides the notional amounts outstanding held by Exelon at March 31, 2025 and December 31, 2024.

	March 31, 2025	December 31, 2024
5-year maturity floating-to-fixed swaps	$ 275	$ 657
10-year maturity floating-to-fixed swaps	275	658
Total	$ 550	$ 1,315

The related AOCI derivative loss for the three months ended March 31, 2025 was $9 million (net of tax). The related AOCI derivative gain for the three months ended March 31, 2024 was immaterial. See Note 13 – Changes in Accumulated Other Comprehensive Income (Loss) for additional information.

Credit Risk

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. The Utility Registrants have contracts to procure electric and natural gas supply that provide suppliers with a certain amount of unsecured credit. If the exposure on the supply contract exceeds the amount of unsecured credit, the suppliers may be required to post collateral. The net credit exposure is mitigated primarily by the ability to recover procurement costs through customer rates. The amount of cash collateral received from external counterparties remained relatively consistent as of March 31, 2025. Cash collateral held by ComEd, PECO, BGE, Pepco, DPL, and ACE must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meets certain qualifications. The following table reflects the Registrants' cash collateral held from external counterparties, which is recorded in Other current liabilities on their respective Consolidated Balance Sheets, as of March 31, 2025 and December 31, 2024:

	March 31, 2025	December 31, 2024
Exelon	$ 225	$ 181
ComEd	181	176

(Dollars in millions, except per share data, unless otherwise noted)

PECO[(a)]	12	—
BGE	1	1
PHI	31	4
Pepco	11	1
DPL	11	2
ACE[(a)]	6	—

(a) PECO and ACE had less than one million in cash collateral held from external parties at December 31, 2024

The Utility Registrants' electric supply procurement contracts do not contain provisions that would require them to post collateral. PECO's, BGE's, and DPL's natural gas procurement contracts contain provisions that could require PECO, BGE, and DPL to post collateral in the form of cash or credit support, which vary by contract and counterparty. As of March 31, 2025, PECO, BGE, and DPL were not required to post collateral for any of these agreements. If PECO, BGE, or DPL lost their investment grade credit rating as of March 31, 2025, they could have been required to post collateral to their counterparties of $45 million, $51 million, and $15 million, respectively.

9. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

Exelon Corporate, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. PECO meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. Pepco, DPL, and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the PHI intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and borrowings from the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements at March 31, 2025 and December 31, 2024.

	Outstanding Commercial Paper at		Average Interest Rate on Commercial Paper Borrowings at	
Commercial Paper Issuer	**March 31, 2025**	**December 31, 2024**	**March 31, 2025**	**December 31, 2024**
Exelon[(a)]	$ 584	$ 1,359	4.62 %	4.66 %
ComEd	$ 347	$ 36	4.61 %	4.55 %
PECO	$ —	$ 192	— %	4.65 %
BGE	$ 237	$ 175	4.63 %	4.61 %
PHI[(b)]	$ —	$ 530	— %	4.70 %
Pepco	$ —	$ 200	— %	4.69 %
DPL	$ —	$ 144	— %	4.74 %
ACE	$ —	$ 186	— %	4.67 %

(a) Exelon Corporate had no outstanding commercial paper borrowings at March 31, 2025 and $426 million in outstanding commercial paper borrowings at December 31, 2024.

(b) Represents the consolidated amounts of Pepco, DPL, and ACE.

Revolving Credit Agreements

On August 29, 2024, Exelon Corporate and each of the Utility Registrants amended and restated their respective syndicated revolving credit facility, extending the maturity date to August 29, 2029. The following table reflects the credit agreements:

Borrower	Aggregate Bank Commitment		Interest Rate
Exelon Corporate	$	900	SOFR plus 1.075%
ComEd	$	1,000	SOFR plus 1.000%
PECO	$	600	SOFR plus 0.900%
BGE	$	600	SOFR plus 0.900%
Pepco	$	300	SOFR plus 1.000%
DPL	$	300	SOFR plus 1.000%
ACE	$	300	SOFR plus 1.000%

Exelon Corporate and the Utility Registrants had no outstanding amounts on the revolving credit facilities as of March 31, 2025.

The Utility Registrants have credit facility agreements, arranged at community banks, which may be utilized to issue letters of credit. The facility agreements have aggregate commitments of $40 million, $40 million, $15 million, $15 million, $15 million, and $15 million, at ComEd, PECO, BGE, Pepco, DPL, and ACE, respectively. These facilities expire on October 3, 2025.

See Note 16 — Debt and Credit Agreements of the 2024 Form 10-K for additional information on the Registrants' credit facilities.

Short-Term Loan Agreements

On March 14, 2024, Exelon Corporate amended and bifurcated the $500 million term loan agreement into two tranches of $350 million and $150 million. The loan agreements were renewed in the first quarter of 2025, extending the expiration date to March 13, 2026. Pursuant to the loan agreements, loans made thereunder bear interest at a variable rate equal to SOFR plus 1.00% and all indebtedness thereunder is unsecured. The loan agreements are reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

(Dollars in millions, except per share data, unless otherwise noted)

Long-Term Debt

Issuance of Long-Term Debt

During the three months ended March 31, 2025, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes[(a)]	6.50%	March 15, 2055	$1,000	Repay outstanding commercial paper obligations, and for general corporate purposes.
Exelon	Notes	5.125%	March 15, 2031	$500	Repay outstanding commercial paper obligations, and for general corporate purposes.
Exelon	Notes	5.875%	March 15, 2055	$500	Repay outstanding commercial paper obligations, and for general corporate purposes.
Pepco[(b)]	First Mortgage Bonds	5.48%	March 26, 2040	$200	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.28%	March 26, 2035	$125	Repay existing indebtedness and for general corporate purposes.
ACE[(c)]	First Mortgage Bonds	5.28%	March 26, 2035	$100	Repay existing indebtedness and for general corporate purposes.

(a) The Junior Subordinated Notes bear interest at 6.50% per annum, commencing February 19, 2025 to, but excluding March 15, 2035. Thereafter, the interest rate resets every five years on March 15 and will be set at a rate per annum equal to the Five-year U.S. Treasury Rate plus a spread of 1.975%.

(b) On March 26, 2025, Pepco entered into a purchase agreement of First Mortgage Bonds of $75 million at 5.78% due on September 17, 2055. The closing date of the issuance is expected to occur in September 2025.

(c) On March 26, 2025, ACE entered into a purchase agreement of First Mortgage Bonds of $75 million and $75 million at 5.54% and 5.81% due on November 19, 2040 and November 19, 2055, respectively. The closing date of the issuance is expected to occur in November 2025.

Debt Covenants

As of March 31, 2025, the Registrants are in compliance with debt covenants.

10. Fair Value of Financial Assets and Liabilities (All Registrants)

Exelon measures and classifies fair value measurements in accordance with the hierarchy as defined by GAAP. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Exelon's valuation techniques used to measure the fair value of the assets and liabilities shown in the tables below are in accordance with the policies discussed in Note 17 — Fair Value of Financial Assets and Liabilities of the 2024 Form 10-K.

(Dollars in millions, except per share data, unless otherwise noted)

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of March 31, 2025 and December 31, 2024. The Registrants have no financial liabilities measured using the NAV practical expedient.

The carrying amounts of the Registrants' short-term liabilities as presented in their Consolidated Balance Sheets are representative of their fair value (Level 2) because of the short-term nature of these instruments.

	March 31, 2025					December 31, 2024				
	Carrying Amount	Fair Value				Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total		Level 1	Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year[(a)]										
Exelon	$46,796	$ —	$37,601	$ 4,159	$41,760	$44,400	$ —	$35,337	$ 3,720	$39,057
ComEd	12,031	—	10,330	—	10,330	12,030	—	10,260	—	10,260
PECO	5,704	—	4,827	—	4,827	5,704	—	4,816	—	4,816
BGE	5,396	—	4,726	—	4,726	5,395	—	4,702	—	4,702
PHI	9,541	—	4,145	4,159	8,304	9,124	—	4,093	3,720	7,813
Pepco	4,559	—	2,499	1,750	4,249	4,362	—	2,475	1,544	4,019
DPL	2,346	—	641	1,378	2,019	2,220	—	623	1,250	1,873
ACE	2,033	—	793	1,031	1,824	1,933	—	787	925	1,712
Long-Term Debt to Financing Trusts										
Exelon	$ 390	$ —	$ —	$ 393	$ 393	$ 390	$ —	$ —	$ 396	$ 396
ComEd	206	—	—	206	206	206	—	—	208	208
PECO	184	—	—	187	187	184	—	—	188	188

(a) Includes unamortized debt issuance costs, unamortized debt discount and premium, net, purchase accounting fair value adjustments, and finance lease liabilities which are not fair valued. Refer to Note 16 — Debt and Credit Agreements of the 2024 Form 10-K for unamortized debt issuance costs, unamortized debt discount and premium, net, and purchase accounting fair value adjustments and Note 10 — Leases of the 2024 Form 10-K for finance lease liabilities.

(Dollars in millions, except per share data, unless otherwise noted)

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Recurring Fair Value Measurements

The following tables present assets and liabilities measured and recorded at fair value in the Registrants' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at March 31, 2025 and December 31, 2024. Exelon and the Utility Registrants have immaterial and no financial assets or liabilities measured using the NAV practical expedient, respectively:

Exelon

	At March 31, 2025				At December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[a]	$ 1,190	$ —	$ —	$ 1,190	$ 544	$ —	$ —	$ 544
Rabbi trust investments								
Cash equivalents	95	—	—	95	94	—	—	94
Mutual funds	63	—	—	63	65	—	—	65
Fixed income	—	6	—	6	—	6	—	6
Life insurance contracts	—	72	22	94	—	73	22	95
Rabbi trust investments subtotal	158	78	22	258	159	79	22	260
Interest rate derivative assets								
Derivatives designated as hedging instruments	—	4	—	4	—	26	—	26
Economic hedges	—	—	—	—	—	—	—	—
Interest rate derivative assets subtotal	—	4	—	4	—	26	—	26
Total assets	1,348	82	22	1,452	703	105	22	830
Liabilities								
Commodity derivative liabilities	—	—	(151)	(151)	—	—	(132)	(132)
Interest rate derivative liabilities								
Derivatives designated as hedging instruments	—	(4)	—	(4)	—	(1)	—	(1)
Economic hedges	—	—	—	—	—	—	—	—
Interest rate derivative liabilities subtotal	—	(4)	—	(4)	—	(1)	—	(1)
Deferred compensation obligation	—	(69)	—	(69)	—	(74)	—	(74)
Total liabilities	—	(73)	(151)	(224)	—	(75)	(132)	(207)
Total net assets (liabilities)	$ 1,348	$ 9	$ (129)	$ 1,228	$ 703	$ 30	$ (110)	$ 623

(a) Exelon excludes cash of $210 million and $219 million at March 31, 2025 and December 31, 2024, respectively, and includes restricted cash of $182 million and $176 million at March 31, 2025 and December 31, 2024, respectively, and long-term restricted cash of zero and $41 million at March 31, 2025 and December 31, 2024, respectively, which is reported in Other deferred debits and other assets in the Consolidated Balance Sheets.

(Dollars in millions, except per share data, unless otherwise noted)

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ComEd, PECO, and BGE

	ComEd				PECO				BGE			
At March 31, 2025	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$345	$ —	$ —	$345	$ 2	$ —	$ —	$ 2	$ 3	$ —	$ —	$ 3
Rabbi trust investments												
Mutual funds	—	—	—	—	11	—	—	11	10	—	—	10
Life insurance contracts	—	—	—	—	—	21	—	21	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	11	21	—	32	10	—	—	10
Total assets	345	—	—	345	13	21	—	34	13	—	—	13
Liabilities												
Commodity derivative liabilities[(b)]	—	—	(151)	(151)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(7)	—	(7)	—	(4)	—	(4)
Total liabilities	—	(8)	(151)	(159)	—	(7)	—	(7)	—	(4)	—	(4)
Total net assets (liabilities)	$345	$ (8)	$(151)	$186	$ 13	$ 14	$ —	$ 27	$ 13	$ (4)	$ —	$ 9

	ComEd				PECO				BGE			
At December 31, 2024	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$390	$ —	$ —	$390	$ 29	$ —	$ —	$ 29	$ 1	$ —	$ —	$ 1
Rabbi trust investments												
Mutual funds	—	—	—	—	12	—	—	12	10	—	—	10
Life insurance contracts	—	—	—	—	—	22	—	22	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	12	22	—	34	10	—	—	10
Total assets	390	—	—	390	41	22	—	63	11	—	—	11
Liabilities												
Commodity derivative liabilities[(b)]	—	—	(132)	(132)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(7)	—	(7)	—	(4)	—	(4)
Total liabilities	—	(8)	(132)	(140)	—	(7)	—	(7)	—	(4)	—	(4)
Total net assets (liabilities)	$390	$ (8)	$(132)	$250	$ 41	$ 15	$ —	$ 56	$ 11	$ (4)	$ —	$ 7

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(a) ComEd excludes cash of $71 million and $66 million at March 31, 2025 and December 31, 2024, respectively, and restricted cash of $181 million and $176 million at March 31, 2025 and December 31, 2024, respectively. Additionally, ComEd includes long-term restricted cash of zero and $41 million at March 31, 2025 and December 31, 2024, respectively, which is reported in Other deferred debits and other assets in the Consolidated Balance Sheets. PECO

excludes cash of $52 million and $19 million at March 31, 2025 and December 31, 2024, respectively. BGE excludes cash of $14 million and $33 million at March 31, 2025 and December 31, 2024, respectively.

(b) The Level 3 balance consists of the current and noncurrent liability of $25 million and $126 million, respectively, at March 31, 2025 and $29 million and $103 million, respectively, at December 31, 2024 related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(Dollars in millions, except per share data, unless otherwise noted)

PHI, Pepco, DPL, and ACE

PHI	At March 31, 2025 Level 1	Level 2	Level 3	Total	At December 31, 2024 Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[(a)]	$ 118	$ —	$ —	$ 118	$ 93	$ —	$ —	$ 93
Rabbi trust investments								
Cash equivalents	93	—	—	93	92	—	—	92
Mutual funds	9	—	—	9	9	—	—	9
Fixed income	—	6	—	6	—	6	—	6
Life insurance contracts	—	23	21	44	—	23	21	44
Rabbi trust investments subtotal	102	29	21	152	101	29	21	151
Total assets	220	29	21	270	194	29	21	244
Liabilities								
Deferred compensation obligation	—	(10)	—	(10)	—	(12)	—	(12)
Total liabilities	—	(10)	—	(10)	—	(12)	—	(12)
Total net assets	$ 220	$ 19	$ 21	$ 260	$ 194	$ 17	$ 21	$ 232

At March 31, 2025	Pepco Level 1	Level 2	Level 3	Total	DPL Level 1	Level 2	Level 3	Total	ACE Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[(a)]	$ 69	$ —	$ —	$ 69	$ 49	$ —	$ —	$ 49	$ —	$ —	$ —	$ —
Rabbi trust investments												
Cash equivalents	92	—	—	92	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	21	44	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	92	23	21	136	—	—	—	—	—	—	—	—
Total assets	161	23	21	205	49	—	—	49	—	—	—	—
Liabilities												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total liabilities	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total net assets	$161	$ 22	$ 21	$204	$ 49	$ —	$ —	$ 49	$ —	$ —	$ —	$ —

(Dollars in millions, except per share data, unless otherwise noted)

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	Pepco				DPL				ACE			
At December 31, 2024	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 21	$ —	$ —	$ 21	$ 3	$ —	$ —	$ 3	$ —	$ —	$ —	$ —
Rabbi trust investments												
Cash equivalents	91	—	—	91	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	21	44	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	91	23	21	135	—	—	—	—	—	—	—	—
Total assets	112	23	21	156	3	—	—	3	—	—	—	—
Liabilities												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total liabilities	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total net assets	$112	$ 22	$ 21	$155	$ 3	$ —	$ —	$ 3	$ —	$ —	$ —	$ —

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(a) PHI excludes cash of $51 million and $70 million at March 31, 2025 and December 31, 2024, respectively, and restricted cash of $1 million and zero at March 31, 2025 and December 31, 2024. Pepco excludes cash of $20 million and $30 million at March 31, 2025 and December 31, 2024, respectively. DPL excludes cash of $12 million and $20 million at March 31, 2025 and December 31, 2024, respectively. ACE excludes cash of $19 million and $14 million at March 31, 2025 and December 31, 2024, respectively and restricted cash of $1 million and zero at March 31, 2025 and December 31, 2024, respectively.

(Dollars in millions, except per share data, unless otherwise noted)

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2025 and 2024:

	Exelon	ComEd		PHI and Pepco
Three Months Ended March 31, 2025	**Total**	**Commodity Derivatives**		**Life Insurance Contracts**
Balance at December 31, 2024	$ (110)	$ (132)		$ 21
Total realized / unrealized gains (losses)				
Included in net income[a]	—	—		—
Included in regulatory assets/liabilities	(19)	(19)	(b)	—
Purchases, sales, and settlements				
Balance at March 31, 2025	$ (129)	$ (151)	(c)	$ 21
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities at March 31, 2025	$ —	$ —		$ —

	Exelon	ComEd		PHI and Pepco
Three Months Ended March 31, 2024	**Total**	**Commodity Derivatives**		**Life Insurance Contracts**
Balance at December 31, 2023	$ (90)	$ (133)		$ 41
Total realized / unrealized gains (losses)				
Included in net income[a]	—	—		—
Included in regulatory assets/liabilities	25	25	(b)	—
Balance at March 31, 2024	$ (65)	$ (108)		$ 41
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities at March 31, 2024	$ —	$ —		$ —

(a) Classified in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income

(b) Includes $30 million of decreases in fair value and an increase for realized gains due to settlements of $11 million recorded in Purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2025. Includes $13 million of increases in fair value and an increase for realized gains due to settlements of $12 million recorded in Purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2024.

(c) The balance of the current and noncurrent asset was effectively zero as of March 31, 2025. The balance consists of a current and noncurrent liability of $25 million and $126 million, respectively, as of March 31, 2025.

Commodity Derivatives (Exelon and ComEd)

(Dollars in millions, except per share data, unless otherwise noted)

The table below discloses the significant unobservable inputs to the forward curve used to value mark-to-market derivatives
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Type of trade	Fair Value at March 31, 2025	Fair Value at December 31, 2024	Valuation Technique	Unobservable Input	2025 Range & Arithmetic Average			2024 Range & Arithmetic Average		
Commodity derivatives	$ (151)	$ (132)	Discounted Cash Flow	Forward power price[(a)]	$28.45 -	$62.87	$38.62	$30.31 -	$59.88	$42.08

(a) An increase to the forward power price would increase the fair value.

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11. Commitments and Contingencies (All Registrants)

The following is an update to the current status of commitments and contingencies set forth in Note 18 — Commitments and Contingencies of the 2024 Form 10-K.

Commitments

PHI Merger Commitments (Exelon, PHI, Pepco, DPL, and ACE). Approval of the PHI Merger in Delaware, New Jersey, Maryland, and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments. The following amounts represent total commitment costs that have been recorded since the acquisition date and the total remaining obligations for Exelon, PHI, Pepco, DPL, and ACE at March 31, 2025:

Description	Exelon	PHI	Pepco	DPL	ACE
Total commitments	$ 513	$ 320	$ 120	$ 89	$ 111
Remaining commitments[(a)]	26	23	22	1	—

(a) Remaining commitments extend through 2026 and include escrow funds, charitable contributions, and rate credits.

(Dollars in millions, except per share data, unless otherwise noted)

Commercial Commitments (All Registrants). The Registrants' commercial commitments at March 31, 2025, representing commitments potentially triggered by future events were as follows:

		Expiration within					
	Total	2025	2026	2027	2028	2029	2030 and beyond
Exelon							
Letters of credit[a]	$ 55	$ 47	$ 8	$ —	$ —	$ —	$ —
Surety bonds[b]	275	182	13	2	78	—	—
Financing trust guarantees[c]	378	—	—	—	78	—	300
Guaranteed lease residual values[d]	24	—	3	4	6	4	7
Total commercial commitments	$ 732	$ 229	$ 24	$ 6	$ 162	$ 4	$ 307
ComEd							
Letters of credit[a]	$ 18	$ 15	$ 3	$ —	$ —	$ —	$ —
Surety bonds[b]	37	32	3	2	—	—	—
Financing trust guarantees[c]	200	—	—	—	—	—	200
Total commercial commitments	$ 255	$ 47	$ 6	$ 2	$ —	$ —	$ 200
PECO							
Letters of credit[a]	$ 4	$ 1	$ 3	$ —	$ —	$ —	$ —
Surety bonds[b]	3	2	1	—	—	—	—
Financing trust guarantees[c]	178	—	—	—	78	—	100
Total commercial commitments	$ 185	$ 3	$ 4	$ —	$ 78	$ —	$ 100
BGE							
Letters of credit[a]	$ 27	$ 27	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	3	2	1	—	—	—	—
Total commercial commitments	$ 30	$ 29	$ 1	$ —	$ —	$ —	$ —
PHI							
Letters of credit[a]	$ 3	$ 3	$ —	$ —	$ —	$ —	$ —

(Dollars in millions, except per share data, unless otherwise noted)

Surety bonds[b]	173	91	4	—	78	—	—
Guaranteed lease residual values[d]	24	—	3	4	6	4	7
Total commercial commitments	$ 200	$ 94	$ 7	$ 4	$ 84	$ 4	$ 7
Pepco							
Letters of credit[a]	$ 2	$ 2	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	162	84	—	—	78	—	—
Guaranteed lease residual values[d]	8	—	1	1	2	1	3
Total commercial commitments	$ 172	$ 86	$ 1	$ 1	$ 80	$ 1	$ 3
DPL							
Letters of credit[a]	$ 1	$ 1	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	6	3	3	—	—	—	—
Guaranteed lease residual values[d]	9	—	1	2	2	2	2
Total commercial commitments	$ 16	$ 4	$ 4	$ 2	$ 2	$ 2	$ 2
ACE							
Surety bonds[b]	$ 5	$ 4	$ 1	$ —	$ —	$ —	$ —
Guaranteed lease residual values[d]	7	—	1	1	2	1	2
Total commercial commitments	$ 12	$ 4	$ 2	$ 1	$ 2	$ 1	$ 2

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(a) Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.

(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds. Historically, payments under the guarantees have not been made and the likelihood of payments being required is remote.

(c) Reflects guarantee of ComEd and PECO securities held by ComEd Financing III, PECO Trust III, and PECO Trust IV.

(d) Represents the maximum potential obligation in the event the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The lease term associated with these assets ranges from 1 to 9 years. The maximum potential obligation at the end of the minimum lease term would be $55 million guaranteed by Exelon and PHI, of which $18 million, $21 million, and $16 million is guaranteed by Pepco, DPL, and ACE, respectively. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Environmental Remediation Matters

General (All Registrants). The Registrants’ operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, the Registrants cannot reasonably estimate whether they will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies, or others, or whether such costs will be recoverable from third parties, including customers. Additional costs could have a material, unfavorable impact on the Registrants' financial statements.

MGP Sites (All Registrants). ComEd, PECO, BGE, and DPL have identified sites where former MGP or gas purification activities have or may have resulted in actual site contamination. For some sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

(Dollars in millions, except per share data, unless otherwise noted)

- ComEd has 16 sites currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2031.
- PECO has 6 sites currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2028.
- BGE has 4 sites currently requiring some level of remediation and/or ongoing activity. BGE expects the majority of the remediation at these sites to continue through at least 2026.
- DPL has 1 site currently under study and the required cost at the site is not expected to be material.

The historical nature of the MGP and gas purification sites, and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to performing any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

ComEd, pursuant to an ICC order, and PECO, pursuant to a PAPUC order, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. While BGE and DPL do not have riders for MGP clean-up costs, they have historically received recovery of actual clean-up costs in distribution rates.

At March 31, 2025 and December 31, 2024, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Accrued expenses, Other current liabilities, and Other deferred credits and other liabilities in their respective Consolidated Balance Sheets:

	March 31, 2025		December 31, 2024	
	Total Environmental Investigation and Remediation Liabilities	Portion of Total Related to MGP Investigation and Remediation	Total Environmental Investigation and Remediation Liabilities	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 396	$ 319	$ 403	$ 322
ComEd	282	282	285	284
PECO	29	27	29	28
BGE	14	10	13	10
PHI	70	—	75	—
Pepco	68	—	73	—
DPL	1	—	1	—
ACE	1	—	1	—

***Benning Road Site (Exelon, PHI, and Pepco)*.** In September 2010, PHI received a letter from the EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site, which is owned by Pepco, was formerly the location of an electric generating facility owned by Pepco subsidiary, Pepco Energy Services (PES), which became a part of Generation following the 2016 merger between PHI and Exelon. This generating facility was deactivated in June 2012. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services (hereinafter "Pepco Entities") with the DOEE, which requires the Pepco Entities to conduct a Remedial Investigation and Feasibility Study (RI/FS) for the Benning

Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River. The purpose of this RI/FS is to define the nature and extent of contamination from the Benning Road site and to evaluate remedial alternatives.

Pursuant to an internal agreement between the Pepco Entities, since 2013, Pepco has performed the work required by the Consent Decree and has been reimbursed for that work by an agreed upon allocation of costs between the Pepco Entities. In September 2019, the Pepco Entities issued a draft “final” RI report which the DOEE approved on February 3, 2020. In October 2022, the DOEE approved dividing the work to complete the landside portion of the FS from the waterside portion to expedite the overall schedule for completion of the project. The landside FS was approved by the DOEE on March 15th, 2024, and the waterside FS was approved by the DOEE on December 16, 2024. On October 3, 2023, the DOEE and Pepco entered into an addendum to the Benning Consent Decree pursuant to which Pepco has agreed to fund or perform the remedial actions to be selected by the DOEE for the landside and waterside areas. This addendum to the Benning Consent Decree was entered by the Court on February 27, 2024 and became effective on that date. Pepco drafted a proposed plan for the landside area, which was approved and issued by the DOEE for public comment on December 16, 2024. The landside area public comment period closed on April 18, 2025. Pepco will submit a matrix of proposed responses to the public comments and a proposed Record of Decision (ROD) to the DOEE for the landside area before August 18, 2025. Pepco also submitted a draft proposed plan to the DOEE for the waterside area on April 15, 2025. The DOEE will review Pepco’s draft and issue a final proposed plan for public comment. After the waterside area public comment period closes, Pepco will submit a matrix of proposed responses to the public comments and a proposed ROD to the DOEE for the waterside area. The DOEE will issue ROD(s) identifying the remedial actions determined to be necessary for the landside and waterside areas.

As part of the separation between Exelon and Constellation in February 2022, the internal agreement between the Pepco Entities for completion and payment for the remaining Consent Decree work was memorialized in a formal agreement for post-separation activities. A second post-separation assumption agreement between Exelon and Constellation transferred any of the potential remaining remediation liability, if any, of PES/Generation to a non-utility subsidiary of Exelon which going forward will be responsible for those liabilities. Exelon, PHI, and Pepco have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

***Anacostia River Tidal Reach (Exelon, PHI, and Pepco)*.** Contemporaneous with the Benning Road site RI/FS being performed by the Pepco Entities, the DOEE and NPS have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-District of Columbia boundary line to the confluence of the Anacostia and Potomac Rivers. The riverwide RI incorporated the results of the river sampling performed by the Pepco Entities as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by the DOEE’s contractor.

On September 30, 2020, the DOEE released its Interim ROD for the Anacostia River sediments. The Interim ROD reflects an adaptive management approach which will require several identified “hot spots” in the river to be addressed first while continuing to conduct studies and to monitor the river to evaluate improvements and determine potential future remediation plans. The adaptive management process chosen by the DOEE is less intrusive, provides more long-term environmental certainty, is less costly, and allows for site specific remediation plans already underway, including the plan for the Benning Road site to proceed to conclusion.

On July 15, 2022, Pepco received a letter from the District of Columbia's Office of the Attorney General (D.C. OAG) on behalf of the DOEE conveying a settlement offer to resolve all PRPs' liability to the District of Columbia (District) for their past costs and their anticipated future costs to complete the work for the Interim ROD. Pepco responded on July 27, 2022 agreeing to enter into settlement discussions. On October 3, 2023, Pepco and the District entered into another consent decree (the “Anacostia River Consent Decree”) pursuant to which Pepco agreed to pay $47 million to resolve its liability to the District for all past costs to perform the riverwide RI/FS and all future costs to complete the work required by the Interim ROD. This amount was agreed to be paid in four equal annual installments beginning a year after the effective date of the Anacostia River Consent Decree. Pepco paid the first installment of $12 million on April 9, 2025. The funds were deposited into the DOEE’s Clean Land

Fund for the District's costs of the Interim ROD work. The Anacostia River Consent Decree caps Pepco's liability for these costs and provides Pepco with the right to seek contributions from other PRPs. The Anacostia River Consent Decree was signed by the judge for the U.S. District Court for the District of Columbia and became effective on April 11, 2024. Exelon, PHI, and Pepco have accrued a liability for Pepco's payment obligations under the Anacostia Consent Decree and management's best estimate of its share of any other future Anacostia River response costs. Pepco has concluded that incremental exposure remains reasonably possible, but management cannot reasonably estimate a range of loss beyond the amounts recorded, which are included in the table above.

In addition to the activities associated with the remedial process outlined above, CERCLA separately requires federal and state (here including Washington, D.C.) Natural Resource Trustees (federal or state agencies designated by the President or the relevant state, respectively, or Indian tribes) to conduct an assessment of any damages to natural resources within their jurisdiction as a result of the contamination that is being remediated. The Trustees can seek compensation from responsible parties for such damages, including restoration costs. During the second quarter of 2018, Pepco became aware that the Trustees are in the beginning stages of a NRD assessment, a process that often takes many years beyond the remedial decision to complete. Pepco has concluded that a loss associated with the eventual NRD assessment is reasonably possible. Due to the early stage of the NRD process, Pepco cannot reasonably estimate the final range of loss potentially resulting from this process. Pepco has become aware, however, that the District is pursuing claims against other parties. Specifically, in January 2025, D.C. OAG filed a lawsuit against the United States seeking to declare the United States liable under CERCLA and the District of Columbia's Brownfield Revitalization Act of 2000 and to recover the District's response costs associated with its investigation and remediation of the river and for future NRDs. This lawsuit is in the early stages. Pepco is monitoring this lawsuit and considering its legal options.

As noted in the Benning Road Site disclosure above, as part of the separation of Exelon and Constellation in February 2022, an assumption agreement was executed transferring any potential future remediation liabilities associated with the Benning Site remediation to a non-utility subsidiary of Exelon. Similarly, any potential future liability associated with the Anacostia River Sediment Project was also assumed by this entity.

Buzzard Point Site (Exelon, PHI, and Pepco). On December 8, 2022, Pepco received a letter from the D.C. OAG, alleging wholly past violations of the District's stormwater discharge and waste disposal requirements related to operations at the Buzzard Point facility, a 9-acre parcel of waterfront property in Washington, D.C. occupied by an active substation and former steam plant building. The letter also alleged wholly past violations by Pepco of stormwater discharge requirements related to its district-wide system of underground vaults. On October 3, 2023, Pepco entered into a Consent Order with the District of Columbia to resolve the alleged

violations without any admission of liability. The Consent Order requires Pepco to pay a civil penalty of $10 million. In addition, Pepco has agreed to assess the environmental conditions at its Buzzard Point facility and conduct any remedial actions deemed necessary as a result of the assessment, and also to assess potential environmental impacts associated with the operation of its underground vaults. The court signed and entered the Consent Order, and it became effective on February 2, 2024. Exelon, PHI, and Pepco have accrued a liability for the projected costs for the required environmental assessments and remediation. In January 2025, Pepco paid the last installment of the civil penalty. Pepco has concluded that incremental exposure remains reasonably possible, but management cannot reasonably estimate a range of loss beyond the amounts recorded, which are included in the table above.

Litigation and Regulatory Matters

DPA and Related Matters (Exelon and ComEd). Exelon and ComEd received a grand jury subpoena in the second quarter of 2019 from the U.S. Attorney's Office for the Northern District of Illinois (USAO) requiring production of information concerning their lobbying activities in the State of Illinois. On October 4, 2019, Exelon and ComEd received a second grand jury subpoena from the USAO requiring production of records of any communications with certain individuals and entities. The Companies cooperated fully with the USAO and any government requests or inquiries. On July 17, 2020, ComEd entered into a DPA with the USAO to resolve the USAO investigation into its historical state legislative lobbying and related practices in Illinois. The agreement resolved the Department of Justice investigation into both ComEd and Exelon, which included a payment to the

U.S. Treasury of $200 million, which was paid in November 2020. The three-year term of the DPA ended on July 17, 2023, and on that same date the court granted the USAO's motion to dismiss the pending charge against ComEd that had been deferred by the DPA.

Subsequent to Exelon announcing the receipt of the USAO subpoenas, various lawsuits were filed related to the subject of the subpoenas and the conduct described in the DPA. Several putative class actions were brought in federal and state court by ComEd customers. These actions were dismissed prior to discovery or trial and those dismissals were affirmed on appeal.

In addition, subsequent to Exelon announcing the receipt of the USAO subpoenas, several shareholders sent letters to the Exelon Board of Directors demanding, among other things, that the Exelon Board of Directors investigate and address alleged breaches of fiduciary duties and other alleged violations by Exelon and ComEd officers and directors related to the conduct described in the DPA. In the first quarter of 2021, the Exelon Board of Directors appointed a Special Litigation Committee (SLC) consisting of disinterested and independent parties to investigate and address these shareholders' allegations and make recommendations to the Exelon Board of Directors based on the outcome of the SLC's investigation. In July 2021, one of the demand letter shareholders filed a derivative action against current and former Exelon and ComEd officers and directors, and against Exelon, as nominal defendant, asserting the same claims made in its demand letter. Since that date, multiple parties have filed separate derivative lawsuits that were subsequently consolidated. On October 12, 2021, the parties filed an agreed motion to stay the litigation for 120 days in order to allow the SLC to continue its investigation, which the court granted. The stay was extended several times. Through mediation efforts, a settlement of the derivative claims was reached by the SLC, the Independent Review Committee of the Board (which had been formed in the third quarter of 2022, to ensure the Board's consideration of any SLC recommendations would be independent and objective), the Board, and certain of the derivative shareholders. On June 16, 2023, the SLC filed a motion for preliminary approval of the settlement, attaching the Stipulation and Agreement of Settlement (Stipulation), which contained the terms of the proposed settlement. The proposed settlement terms include but are not limited to: a payment of $40 million to Exelon by Exelon's insurers of which $10 million constitutes the attorneys' fee award to be paid to the Settling Shareholders' counsel; various compliance and disclosure-related reforms; and certain changes in Board and Committee composition. The non-settling shareholders objected to the settlement and opposed preliminary approval. On September 20, 2024, the court denied without prejudice the SLC's motion for preliminary approval. The court's order provided that if the SLC can substantiate or otherwise revise the attorneys' fees aspect of the settlement, then the SLC could renew its motion for preliminary approval by October 21, 2024. On October 21, 2024, the SLC filed its second renewed motion for preliminary approval, and the Settling Shareholders filed a brief in support of the SLC's second renewed motion for preliminary approval. On November 20, 2024, the non-settling plaintiffs filed an opposition to the renewed motion for preliminary approval. On December 18, 2024, the SLC and Settling Shareholders filed replies in support of the renewed motion for preliminary approval.

Maryland Sales and Use Tax Refund Claim (Exelon, BGE, PHI, Pepco, and DPL). Maryland imposes a 6% sales and use tax on the purchase of most goods and services. BGE, Pepco, and DPL have filed or plan to file protective refund claims, totaling an estimated $100 million, treating electric transmission and distribution machinery and equipment as nontaxable pursuant to the manufacturing exemption available under the Maryland sales and use tax law. The Maryland Comptroller has initially denied the refund claim and litigation is pending.

On November 22, 2024, the Appellate Court of Maryland, in a case involving a regulated electric utility operating in Maryland, ruled the purchase of certain transmission and distribution equipment qualify for the sales tax manufacturing exemption. On December 20, 2024, the Maryland Attorney General, on behalf of the Maryland Comptroller, filed a motion for reconsideration with the Appellate Court of Maryland of its ruling. The motion for reconsideration was denied on February 3, 2025.

On February 18, 2025, the Maryland Attorney General, on behalf of the Maryland Comptroller, filed a petition with the Maryland Supreme Court requesting review of the Appellate Court of Maryland's ruling.

In the event transmission and distribution equipment is determined to be exempt, Exelon, BGE, PHI, Pepco, and

(Dollars in millions, except per share data, unless otherwise noted)

DPL will record estimated receivables of $100 million, $65 million, $35 million, $25 million, and $10 million, respectively. The sales tax payments were primarily capitalized; therefore, the refund would be recorded as a reduction to property, plant, and equipment included in rate base.

General (All Registrants). The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The Registrants are also from time to time subject to audits and investigations by the FERC and other regulators. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

12. Shareholders' Equity (Exelon)

At-the-Market Program

On August 4, 2022, Exelon executed an equity distribution agreement (“Equity Distribution Agreement”), with certain sales agents and forward sellers and certain forward purchasers, establishing an ATM equity distribution program under which it may offer and sell shares of its Common stock, having an aggregate gross sales price of up to $1 billion. Exelon has no obligation to offer or sell any shares of Common stock under the Equity Distribution Agreement and may, at any time, suspend or terminate offers and sales under the Equity Distribution Agreement.

During the first quarter 2025, Exelon issued approximately 4.0 million shares of Common stock at an average gross price of $43.42 per share. The net proceeds from the issuance were $173 million, which were used for general corporate purposes.

In the first quarter of 2025, Exelon entered into two separate forward sale agreements for 1.7 million shares and 4.0 million shares of Common stock, with an initial forward price of $42.81 and $43.42 per share, respectively. The forward sale agreements require Exelon to, at its election prior to December 15, 2025, either (i) physically settle the transactions by issuing shares of its Common stock to the forward counterparties in exchange for net proceeds at the then-applicable forward sale price specified by the agreements or (ii) net settle the transactions in whole or in part through the delivery to the forward counterparties or receipt from the forward counterparties of cash or shares in accordance with the provisions of the agreements. No amounts have been or will be recorded on Exelon's balance sheet with respect to the equity offerings until the equity forward sale agreements have been settled. Each initial forward sale price is subject to adjustment on a daily basis based on a floating interest rate factor and will decrease by other fixed amounts specified in the agreements. Until settlement of the equity forward, earnings per share dilution resulting from the agreement, if any, will be determined under the treasury stock method. For the three months ended March 31, 2025, approximately 5.6 million shares under the forward sale agreements were not included in the calculation of diluted earnings per share because their effect would have been antidilutive.

Inclusive of the impact of the forward sale agreements, $283 million of Common stock remained available for sale pursuant to the ATM program as of March 31, 2025.

13. Changes in Accumulated Other Comprehensive Income (Loss) (Exelon)

The following table presents changes in Exelon's AOCI, net of tax, by component:

Three Months Ended March 31, 2025	Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items [(a)]	Total
Balance at December 31, 2024	$ 45	$ (765)	$ (720)
OCI before reclassifications	(6)	5	(1)

(Dollars in millions, except per share data, unless otherwise noted)

Amounts reclassified from AOCI	(2)	5	3
Net current-period OCI	(8)	10	2
Balance at March 31, 2025	$ 37	$ (755)	$ (718)

Three Months Ended March 31, 2024	Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items (a)	Total
Balance at December 31, 2023	$ (3)	$ (723)	$ (726)
OCI before reclassifications	34	(24)	10
Amounts reclassified from AOCI	(1)	5	4
Net current-period OCI	33	(19)	14
Balance at March 31, 2024	$ 30	$ (742)	$ (712)

(a) This AOCI component is included in the computation of net periodic pension and OPEB cost. See Note 14 — Retirement Benefits and Note 7 — Retirement Benefits of the 2024 Form 10-K for additional information. See Exelon's Statements of Operations and Comprehensive Income for individual components of AOCI.

The following table presents Income tax benefit (expense) allocated to each component of Exelon's Other comprehensive income (loss):

	Three Months Ended March 31,	
	2025	2024
Pension and non-pension postretirement benefit plans:		
Actuarial losses reclassified to periodic benefit cost	$ (2)	$ (2)
Pension and non-pension postretirement benefit plans valuation adjustments	(2)	8
Unrealized gains on cash flow hedges	3	(10)

14. Supplemental Financial Information (All Registrants)

Supplemental Statement of Operations Information

The following tables provide additional information about material items recorded in the Registrants' Consolidated Statements of Operations and Comprehensive Income:

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	Taxes other than income taxes							
Three Months Ended March 31, 2025	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes[a]	$ 258	$ 81	$ 50	$ 34	$ 93	$ 84	$ 8	$ 1
Property	111	9	5	57	40	28	12	—
Payroll	33	8	5	5	7	1	1	1

(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended March 31, 2024								
Utility taxes[a]	$ 229	$ 75	$ 41	$ 31	$ 82	$ 74	$ 8	$ —
Property	105	9	4	53	38	26	11	1
Payroll	34	9	5	5	7	2	1	1

(a) The Registrants' utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

	Other, net							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2025								
AFUDC — Equity	$ 39	$ 12	$ 7	$ 9	$ 11	$ 8	$ 2	$ 1
Non-service net periodic benefit cost	(13)	—	—	—	—	—	—	—
Three Months Ended March 31, 2024								
AFUDC — Equity	$ 40	$ 10	$ 8	$ 7	$ 15	$ 12	$ 3	$ —
Non-service net periodic benefit cost	(7)	—	—	—	—	—	—	—

Supplemental Cash Flow Information

The following tables provide additional information about material items recorded in the Registrants' Consolidated Statements of Cash Flows.

	Depreciation, amortization, and accretion							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2025								
Property, plant, and equipment[a]	$ 750	$ 302	$ 108	$ 124	$ 201	$ 88	$ 57	$ 55

(Dollars in millions, except per share data, unless otherwise noted)

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Amortization of regulatory assets and liabilities, net[(a)]	152	78	1	40	33	17	6	9
Amortization of intangible assets, net[(a)]	2	—	—	—	—	—	—	—
ARO accretion[(b)]	1	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$ 905	$ 380	$ 109	$ 164	$ 234	$ 105	$ 63	$ 64
Three Months Ended March 31, 2024								
Property, plant, and equipment[(a)]	$ 711	$ 284	$ 101	$ 122	$ 190	$ 81	$ 52	$ 53
Amortization of regulatory assets and liabilities, net[(a)]	166	78	3	28	56	26	9	21
Amortization of intangible assets, net[(a)]	2	—	—	—	—	—	—	—
ARO accretion[(b)]	1	—	—	—	—	—	—	—
Total depreciation and amortization	$ 880	$ 362	$ 104	$ 150	$ 246	$ 107	$ 61	$ 74

(a) Included in Depreciation and amortization expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

(b) Included in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

	Other non-cash operating activities							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Three Months Ended March 31, 2025								
Pension and OPEB costs	$ 68	$ 21	$ 2	$ 16	$ 25	$ 8	$ 4	$ 3
Allowance for credit losses	97	11	43	14	29	10	9	10
True-up adjustments to decoupling mechanisms and formula rates[(a)]	136	85	9	29	13	(2)	5	10
Amortization of operating ROU asset	9	—	—	2	6	1	2	2
AFUDC — Equity	(39)	(12)	(7)	(9)	(11)	(8)	(2)	(1)
Three Months Ended March 31, 2024								
Pension and OPEB costs	$ 61	$ 17	$ —	$ 15	$ 23	$ 9	$ 4	$ 3
Allowance for credit losses	63	2	27	12	22	16	3	3
True-up adjustments to decoupling mechanisms and formula rates[(a)]	(91)	(19)	2	(43)	(31)	(29)	4	(6)
Amortization of operating ROU asset	9	—	—	2	6	1	2	1
AFUDC — Equity	(40)	(10)	(8)	(7)	(15)	(12)	(3)	—

(a) For ComEd, reflects the true-up adjustments in Regulatory assets and liabilities associated with its distribution MRP and distribution, energy efficiency, distributed generation, and transmission formula rates. For PECO, reflects the change in Regulatory assets and liabilities associated with its transmission formula rates. For BGE, Pepco, DPL, and ACE, reflects the change in Regulatory assets and liabilities associated with their decoupling mechanisms and transmission formula rates. See Note 3 — Regulatory Matters of the 2024 Form 10-K for additional information.

The following tables provide a reconciliation of cash, cash equivalents, and restricted cash reported within the

(Dollars in millions, except per share data, unless otherwise noted)

Registrants' Consolidated Balance Sheets that sum to the total of the same amounts in their Consolidated Statements of Cash Flows.

	Cash, cash equivalents, and restricted cash							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at March 31, 2025								
Cash and cash equivalents	$ 1,004	$ 96	$ 54	$ 14	$ 127	$ 58	$ 50	$ 18
Restricted cash and cash equivalents	578	501	—	3	43	31	11	1
Restricted cash included in Other deferred debits and other assets	—	—	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,582	$ 597	$ 54	$ 17	$ 170	$ 89	$ 61	$ 19
Balance at December 31, 2024								
Cash and cash equivalents	$ 357	$ 105	$ 48	$ 33	$ 139	$ 30	$ 21	$ 14
Restricted cash and cash equivalents	541	486	—	1	24	21	2	—
Restricted cash included in Other deferred debits and other assets	41	41	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 939	$ 632	$ 48	$ 34	$ 163	$ 51	$ 23	$ 14
Balance at March 31, 2024								
Cash and cash equivalents	$ 720	$ 100	$ 39	$ 27	$ 504	$ 198	$ 269	$ 27
Restricted cash and cash equivalents	489	428	9	—	23	22	1	—
Restricted cash included in Other deferred debits and other assets	99	99	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,308	$ 627	$ 48	$ 27	$ 527	$ 220	$ 270	$ 27

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the 2024 Form 10-K.

Supplemental Balance Sheet Information

The following table provides additional information about material items recorded in the Registrants' Consolidated Balance Sheets.

	Accrued expenses							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at March 31, 2025								
Compensation-related accruals[a]	$ 377	$ 115	$ 53	$ 51	$ 64	$ 19	$ 13	$ 9
Taxes accrued	222	148	31	81	138	116	21	12
Interest accrued	440	89	56	77	83	37	27	17
Balance at December 31, 2024								
Compensation-related accruals[a]	$ 679	$ 197	$ 87	$ 88	$ 132	$ 38	$ 26	$ 18
Taxes accrued	217	96	13	34	110	92	11	11
Interest accrued	468	150	60	50	83	44	16	18

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.

15. Related Party Transactions (All Registrants)

Service Company Costs for Corporate Support

The Registrants receive a variety of corporate support services from BSC. Pepco, DPL, and ACE also receive corporate support services from PHISCO. See Note 1 — Significant Accounting Policies for additional information regarding BSC and PHISCO.

The following table presents the service company costs allocated to the Registrants:

	Operating and maintenance from affiliates		Capitalized costs	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2025	2024	2025	2024
Exelon				
BSC			$ 160	$ 158
PHISCO			25	29
ComEd				
BSC	$ 100	$ 100	62	71
PECO				
BSC	59	58	27	29
BGE				
BSC	63	59	33	24
PHI				
BSC	52	50	39	34
PHISCO	—	—	25	29
Pepco				
BSC	32	31	17	17
PHISCO	31	33	10	12
DPL				
BSC	20	19	12	12
PHISCO	25	25	8	9
ACE				
BSC	16	16	8	5
PHISCO	23	23	7	8

(Dollars in millions, except per share data, unless otherwise noted)

Current Receivables from/Payables to Affiliates

The following tables present current Receivables from affiliates and current Payables to affiliates:

March 31, 2025

	Receivables from affiliates:									
Payables to affiliates:	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**BSC**	**PHISCO**	**Other**	**Total**
ComEd		$ —	$ —	$ —	$ —	$ —	$ 58	$ —	$ 2	$ 60
PECO	$ 1		—	—	—	—	30	—	6	37
BGE	1	—		—	—	—	36	—	1	38
PHI	1	—	—	—	—	—	7	—	11	19
Pepco	—	—	—		—	—	17	16	1	34
DPL	1	—	—	—		—	11	12	(1)	23
ACE	—	—	—	—	—		10	11	(1)	20
Other	4	—	—	—	1	7	—	—		12
Total	$ 8	$ —	$ —	$ —	$ 1	$ 7	$ 169	$ 39	$ 19	$ 243

December 31, 2024

	Receivables from affiliates:									
Payables to affiliates:	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**BSC**	**PHISCO**	**Other**	**Total**
ComEd		$ —	$ —	$ —	$ —	$ —	$ 67	$ —	$ 10	$ 77
PECO	$ —		—	—	—	—	37	—	4	41
BGE	—	—		—	—	—	47	—	1	48
PHI	—	—	—	—	—	—	7	1	10	18
Pepco	—	—	—		—	—	21	15	1	37
DPL	—	—	—	—		—	14	11	1	26
ACE	—	—	—	—	—		11	10	1	22
Other	4	—	—	1	—	7	—	—		12
Total	$ 4	$ —	$ —	$ 1	$ —	$ 7	$ 204	$ 37	$ 28	$ 281

Borrowings from Exelon/PHI intercompany money pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing both Exelon and PHI operate an intercompany money pool. PECO and PHI Corporate participate in the Exelon intercompany money pool. Pepco, DPL, and ACE participate in the PHI intercompany money pool.

Long-term debt to financing trusts

The following table presents Long-term debt to financing trusts:

	March 31, 2025			December 31, 2024		
	Exelon	**ComEd**	**PECO**	**Exelon**	**ComEd**	**PECO**
ComEd Financing III	$ 206	$ 206	$ —	$ 206	$ 206	$ —
PECO Trust III	81	—	81	81	—	81
PECO Trust IV	103	—	103	103	—	103
Total	$ 390	$ 206	$ 184	$ 390	$ 206	$ 184

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Dollars in millions except per share data, unless otherwise noted)

Exelon

Executive Overview

Exelon is a utility services holding company engaged in the energy transmission and distribution businesses through it's six reportable segments: ComEd, PECO, BGE, Pepco, DPL, and ACE. See Note 1 — Significant Accounting Policies and Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's principal subsidiaries and reportable segments.

Exelon’s consolidated financial information includes the results of its seven separate operating subsidiary registrants, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management’s Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth Exelon's GAAP consolidated Net income attributable to common shareholders by Registrant for the three months ended March 31, 2025 compared to the same period in 2024. For additional information regarding the financial results for the three months ended March 31, 2025 and 2024, see the discussions of Results of Operations by Registrant.

	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024	Favorable (Unfavorable) Variance
Exelon	$ 908	$ 658	$ 250
ComEd	302	193	109
PECO	266	149	117
BGE	260	264	(4)
PHI	194	168	26
Pepco	97	75	22
DPL	69	66	3
ACE	31	29	2
Other[a]	(114)	(116)	2

(a) Other primarily includes eliminating and consolidating adjustments, Exelon’s corporate operations, shared service entities, and other financing and investment activities.

***Three Months Ended March 31, 2025 Compared to Three Months Ended March 31, 2024*. Net income attributable to common shareholders** increased by $250 million and diluted earnings per average common share increased to $0.90 in 2025 from 0.66 in 2024 primarily due to:

- Timing of distribution earnings at ComEd;
- Favorable impacts of rate increases at ComEd, PECO, BGE and PHI;
- Normal weather at PECO compared to unfavorable weather in the prior period;
- Timing of income tax expense at PECO; and
- Higher return on regulatory assets at ComEd.

The increases were partially offset by:

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- Higher interest expense at PECO, BGE and PHI; and
- Lower transmission peak load due to lower energy demand at ComEd.

Adjusted (non-GAAP) operating earnings. In addition to Net income, Exelon evaluates its operating performance using the measure of Adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses, and other specified items. This information is intended to enhance an investor's overall understanding of year-over-year operating results and provide an indication of Exelon's baseline operating performance excluding items not considered by management to be 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. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between GAAP Net income attributable to common shareholders and Adjusted (non-GAAP) operating earnings for the three months ended March 31, 2025 compared to the same period in 2024:

	Three Months Ended March 31,			
	2025		2024	
(In millions, except per share data)		Earnings per Diluted Share		Earnings per Diluted Share
Net income attributable to common shareholders	**$ 908**	**$ 0.90**	**$ 658**	**$ 0.66**
Regulatory matters (net of taxes of $7)[(a)]	22	0.02	—	—
Change in FERC audit liability (net of taxes of $1 and $9, respectively)	2	—	27	0.03
Cost management charge (net of taxes of $0)[(b)]	(1)	—	—	—
Adjusted (non-GAAP) operating earnings	**$ 932**	**$ 0.92**	**$ 685**	**$ 0.68**

Note:
Amounts may not sum due to rounding.
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net income attributable to common shareholders and Adjusted (non-GAAP) operating earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. The marginal statutory income tax rates for 2025 and 2024 ranged from 24.0% to 29.0%.

(a) Represents the probable disallowance of certain capitalized costs.
(b) Primarily represents severance and reorganization costs related to cost management.

Significant 2025 Transactions and Developments

Distribution Base Rate Case Proceedings

The Utility Registrants file base rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants' current and future financial statements.

The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2025. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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Completed Distribution Base Rate Case Proceedings

Registrant/ Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois	January 17, 2023	Electric	$ 1,487	$ 1,045	8.905%	December 19, 2024	January 1, 2024
	April 26, 2024 (amended on September 11, 2024)	Electric	$ 624	$ 623	9.89%	October 31, 2024	January 1, 2025
PECO - Pennsylvania	March 28, 2024	Electric	$ 464	$ 354	N/A[(e)]	December 12, 2024	January 1, 2025
		Natural Gas	$ 111	$ 78			
BGE - Maryland	February 17, 2023	Electric	$ 313	$ 179	9.50 %	December 14, 2023	January 1, 2024
		Natural Gas	$ 289	$ 229	9.45 %		
Pepco - District of Columbia	April 13, 2023 (amended February 27, 2024)	Electric	$ 186	$ 123	9.50%	November 26, 2024	January 1, 2025
Pepco - Maryland	May 16, 2023 (amended February 23, 2024)	Electric	$ 111	$ 45	9.50 %	June 10, 2024	April 1, 2024
DPL - Maryland	May 19, 2022	Electric	$ 38	$ 29	9.60 %	December 14, 2022	January 1, 2023
DPL - Delaware	December 15, 2022 (amended September 29, 2023)	Electric	$ 39	$ 28	9.60 %	April 18, 2024	July 15, 2023
ACE - New Jersey	February 15, 2023 (amended August 21, 2023)	Electric	$ 92	$ 45	9.60 %	November 17, 2023	December 1, 2023

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Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
DPL - Delaware	September 20, 2024 (amended February 28, 2025)	Natural Gas	$ 42	10.65 %	First quarter of 2026
ACE - New Jersey	November 21, 2024	Electric	109	10.70%	Fourth quarter of 2025

Transmission Formula Rates

For 2025, the following total increase was included in the Utility Registrant's electric transmission formula rate update. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Registrant	Initial Revenue Requirement Increase	Annual Reconciliation Increase	Total Revenue Requirement Increase	Allowed Return on Rate Base	Allowed ROE
BGE	$ 21	$ 21	$ 35	7.53 %	10.50 %

ComEd's FERC Audit

The Utility Registrants are subject to periodic audits and investigations by FERC. FERC’s Division of Audits and Accounting initiated a nonpublic audit of ComEd in April 2021 evaluating ComEd’s compliance with (1) approved terms, rates and conditions of its federally regulated service; (2) accounting requirements of the Uniform System of Accounts; (3) reporting requirements of the FERC Form 1; and (4) the requirements for record retention. The audit period extended back to January 1, 2017.

On July 27, 2023, FERC published a final audit report which included, among other things, findings and recommendations related to ComEd's methodology regarding the allocation of certain overhead costs to capitalized construction costs under FERC regulations, including a suggestion that refunds may be due to customers for amounts collected in previous years. ComEd responded to that report and on August 28, 2023, ComEd filed a formal notice of the issues it contested within the audit report. On December 14, 2023, FERC appointed a settlement judge for the contested overhead allocation findings and set the matter for a trial-type hearing. That hearing process was held in abeyance while a formal settlement process, which began in February 2024, took place.

On July 30, 2024, ComEd reached an agreement in principle on the contested overhead allocation finding. As a result of the settlement process, ComEd recorded a charge for the probable disallowance of $70 million of certain currently capitalized construction costs to operating expenses, which are not expected to be recovered in future rates. The existing loss estimate was reflected in Exelon and ComEd's financial statements as of December 31, 2024. ComEd and FERC staff jointly filed the settlement agreement with FERC for approval on February 11, 2025. The settlement was approved by FERC on April 4, 2025.

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Other Key Business Drivers and Management Strategies

The following discussion of other key business drivers and management strategies includes current developments of previously disclosed matters and new issues arising during the period that may impact future financial statements. This section should be read in conjunction with ITEM 1. Business in the 2024 Form 10-K, ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Key Business Drivers and Management Strategies in the 2024 Form 10-K, and Note 11 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in this report for additional information on various environmental matters.

Allocation of Income Taxes to Regulated Utilities (All Registrants)

In Q2 2024, the IRS issued a series of PLRs, to another taxpayer, providing guidance with respect to the application of the tax normalization rules to the allocation of consolidated tax benefits among the members of a consolidated group associated with NOLC for ratemaking purposes. The rulings provide that for ratemaking purposes the tax benefit of NOLC should be reflected on a separate company basis not taking into consideration the utilization of losses by other affiliates. A PLR issued to another taxpayer may not be relied on as precedent.

For the Registrants, except for PECO, the methodology prescribed by the IRS in these PLRs could result in a reduction of the regulatory liability established for EDITs arising from the TCJA corporate tax rate change that is being amortized and flowed through to customers as well as a reduction in the accumulated deferred income taxes included in rate base for ratemaking purposes of approximately $1.2 billion - $1.7 billion.

The Utility Registrants, except for PECO, filed PLR requests with the IRS confirming the treatment of the NOLC for ratemaking purpose. The Utility Registrants will record the impact, if any, upon receiving the PLR from the IRS.

Legislative and Regulatory Developments

Infrastructure Investment and Jobs Act

On November 15, 2021, President Biden signed the $1.2 trillion IIJA into law. IIJA provides for approximately $550 billion in new federal spending. Categories of funding include funding for a variety of infrastructure needs, including but not limited to: (1) power and grid reliability and resilience, (2) resilience for cybersecurity to address critical infrastructure needs, and (3) electric vehicle charging infrastructure for alternative fuel corridors. The Registrants continue to evaluate programs under the legislation and consider possible opportunities to apply for funding, either directly or in potential collaborations with state and/or local agencies and key stakeholders. The Registrants cannot predict the ultimate timing and success of securing funding from programs under IIJA.

The Trump Administration has issued numerous Executive Orders (EOs), including the Unleashing American Energy Order on January 20, 2025, which requires an immediate pause in the disbursement of funds appropriated through the IRA and IIJA during a 90-day review period, which is still in effect. Exelon is currently evaluating this EO and others to determine what, if any, impact they might have on awards selected or received from the Department of Energy in 2024.

Next Generation Energy Act

On April 7, 2025, the Maryland General Assembly, passed legislation that addresses several matters pertaining to electric and gas utilities, including affirming that the MDPSC may approve the use of multi-year rate plans that are proven to be beneficial to customers, among other things. It also prohibits utilities from filing after January 1, 2025, for the reconciliation of actuals costs and revenues to amounts approved within the multi-year plans. As of March 31, 2025, BGE has a regulatory asset of $10 million and a regulatory liability of $10 million for multi-year plan reconciliations yet to be filed. DPL has a regulatory liability of $7 million for multi-year reconciliations yet to be filed. Multi-year plan reconciliations filed prior to January 1, 2025, remain lawful and will be resolved in their respective proceedings. The legislation is pending the signature of the Governor. Exelon, BGE, Pepco, and DPL are in the process of assessing the potential impacts of the pending legislation.

Critical Accounting Policies and Estimates

Management of each of the Registrants makes a number of significant estimates, assumptions, and judgments in the preparation of its financial statements. As of March 31, 2025, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2024. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in the 2024 Form 10-K for further information.

Results of Operations by Registrant

Results of Operations — ComEd

	Three Months Ended March 31,		(Unfavorable) Favorable Variance
	2025	2024	
Operating revenues	$ 2,065	$ 2,095	$ (30)
Operating expenses			
Purchased power	689	907	218
Operating and maintenance	423	418	(5)
Depreciation and amortization	380	362	(18)
Taxes other than income taxes	99	94	(5)
Total operating expenses	1,591	1,781	190
Operating income	474	314	160
Other income and (deductions)			
Interest expense, net	(128)	(122)	(6)
Other, net	21	20	1
Total other income and (deductions)	(107)	(102)	(5)
Income before income taxes	367	212	155
Income taxes	65	19	(46)
Net income	$ 302	$ 193	$ 109

***Three Months Ended March 31, 2025 Compared to Three Months Ended March 31, 2024*. Net income** increased by $109 million as compared to the same period in 2024, primarily due to timing of distribution earnings, higher distribution and transmission rate base, and higher return on regulatory assets primarily due to an increase in asset balances. These were partially offset by lower transmission peak load.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2025
	Increase (Decrease)
Distribution	$ 129
Transmission	22
Energy efficiency	10

Other	9
	170
Regulatory required programs	(200)
Total decrease	$ (30)

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. Operating revenues are not impacted by abnormal weather, usage per customer, or number of customers as a result of revenue decoupling mechanisms.

Distribution Revenue. Starting in 2024, distribution revenues are under a MRP. The MRP requires an annual reconciliation of the revenue requirement in effect to the actual costs the ICC determines are prudently and reasonably incurred. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, (e.g., severe weather and storm restoration), investments being recovered, and allowed ROE. Electric distribution revenues increased for the three months ended March 31, 2025 as compared to the same period in 2024, primarily due to differences in the timing of distribution earnings and higher rate base.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, and the highest daily peak load, which is updated annually in January based on the prior calendar year. Transmission revenues increased

for the three months ended March 31, 2025 as compared to the same period in 2024, primarily due to higher fully recoverable costs and the impacts of higher rate base, partially offset by lower transmission peak load.

Energy Efficiency Revenue. Energy efficiency revenues are under a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs the ICC determines are prudently and reasonably incurred in a given year. Energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. Energy efficiency revenues increased for the three months ended March 31, 2025 as compared to the same periods in 2024, primarily due to increased regulatory asset amortization, which is fully recoverable.

Other Revenue primarily includes assistance provided to other utilities through mutual assistance programs. Other revenues increased for the three months ended March 31, 2025 as compared to the same periods in 2024, which primarily reflects increased mutual assistance revenues associated with storm restoration efforts.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as recoveries under the credit loss expense tariff, environmental costs associated with MGP sites, ETAC, and costs related to electricity, ZEC, CMC, and REC procurement. ETAC is a retail customer surcharge collected and remitted to an Illinois state agency for programs to support clean energy jobs and training. The riders are designed to provide full and current cost recovery. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries as ComEd remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, ComEd either acts as the billing agent or the competitive supplier separately bills its own customers, and therefore does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from ComEd, ComEd is permitted to recover the electricity, ZEC, CMC, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power expense related to the electricity, ZECs, CMCs, and RECs.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The $218 million decrease in **Purchased power expense** for the three months ended March 31, 2025 compared to the same periods in 202 is offset in Operating revenues as part of regulatory required

4 programs.

The changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended March 31, 2025
	(Decrease) Increase
Labor, other benefits, contracting, and materials	$ (27)
Storm-related costs	(6)
Pension and non-pension postretirement benefits expense	2
Other	40
	9
Regulatory required programs	(4)
Total increase	$ 5

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2025
	Increase
Depreciation and amortization[a]	$ 18
Total increase	$ 18

(a) Reflects ongoing capital expenditures.

Effective income tax rates were 17.7% and 9.0% for the three months ended March 31, 2025 and 2024, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations — PECO

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2025	2024	
Operating revenues	$ 1,333	$ 1,054	$ 279
Operating expenses			
Purchased power and fuel	502	403	(99)
Operating and maintenance	327	293	(34)
Depreciation and amortization	109	104	(5)
Taxes other than income taxes	60	51	(9)
Total operating expenses	998	851	(147)
Gain on sales of assets	—	2	(2)
Operating income	335	205	130
Other income and (deductions)			
Interest expense, net	(63)	(55)	(8)
Other, net	8	9	(1)
Total other income and (deductions)	(55)	(46)	(9)
Income before income taxes	280	159	121
Income taxes	14	10	(4)
Net income	$ 266	$ 149	$ 117

Three Months Ended March 31, 2025 Compared to Three Months Ended March 31, 2024**. Net income** increased by $117 million, due to an increase in revenue as a result of an increase in electric and gas distribution rates coupled with relatively normal weather compared to unfavorable weather in the same period last year and a decrease in income tax expense due to timing of tax repairs deduction, partially offset by an increase in credit loss expense and interest expense.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2025		
	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 23	$ 21	$ 44
Volume	9	2	11
Pricing	73	38	111
Transmission	(6)	—	(6)
Other	5	3	8
	104	64	168
Regulatory required programs	71	40	111
Total increase	$ 175	$ 104	$ 279

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended March 31, 2025 compared to the same period in 2024, Operating revenues related to weather increased due to relatively normal weather compared to unfavorable weather conditions in PECO's service territory.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in PECO's service territory. The changes in heating and cooling degree-days in

PECO’s service territory for the three months ended March 31, 2025 compared to the same period in 2024 and normal weather consisted of the following:

PECO Service Territory	Three Months Ended March 31, 2025	2024	Normal	% Change 2025 vs. 2024	2025 vs. Normal
Heating Degree-Days	2,351	2,089	2,388	12.5 %	(1.5)%
Cooling Degree-Days	1	—	1	N/A	— %

Volume. Electric volume, exclusive of the effects of weather, for the three months ended March 31, 2025 compared to the same period in 2024, remained relatively consistent. Natural gas volume for the three months ended March 31, 2025 compared to the same period in 2024, remained relatively consistent.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31, 2025	2024	% Change	Weather - Normal % Change [(b)]
Residential	3,859	3,455	11.7 %	3.3 %
Small commercial & industrial	1,946	1,891	2.9 %	(1.0)%
Large commercial & industrial	3,425	3,355	2.1 %	(0.4)%
Public authorities & electric railroads	189	179	5.6 %	5.6 %
Total electric retail deliveries[(a)]	9,419	8,880	6.1 %	1.1 %

Number of Electric Customers	At March 31, 2025	At March 31, 2024
Residential	1,540,453	1,540,491
Small commercial & industrial	155,131	156,475
Large commercial & industrial	3,151	3,160
Public authorities & electric railroads	10,703	10,713
Total	1,709,438	1,710,839

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(a) Reflects delivery volumes from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Natural Gas Deliveries to Customers (in mmcf)	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024	% Change	Weather - Normal % Change [b]
Residential	21,834	18,895	15.6 %	(0.3)%
Small commercial & industrial	10,405	9,488	9.7 %	(2.2)%
Large commercial & industrial	12	16	(25.0)%	— %
Transportation	7,242	6,899	5.0 %	1.0 %
Total natural gas retail deliveries[a]	39,493	35,298	11.9 %	(0.6)%

Number of Natural Gas Customers	At March 31, 2025	At March 31, 2024
Residential	509,773	508,429
Small commercial & industrial	44,869	45,038
Large commercial & industrial	7	7
Transportation	623	646
Total	555,272	554,120

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(a) Reflects delivery volumes from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Pricing for the three months ended March 31, 2025 compared to the same period in 2024 increased primarily due to an increase in electric and gas distribution rates charged to customers.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue decreased for the three months ended March 31, 2025 compared to the same period in 2024 primarily due to decreases in underlying costs and capital investments.

Other revenue primarily includes revenue related to late payment charges. Other revenue for the three months ended March 31, 2025 compared to the same period in 2024 remained relatively consistent.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency, PGC, TSC, and the GSA. The riders are designed to provide full and current cost recovery, and in some cases, a return. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries as PECO remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, PECO either acts as the billing agent or the competitive supplier separately bills its own customers and therefore PECO does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from PECO, PECO is permitted to recover the electricity, natural gas, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power and fuel expense related to the electricity, natural gas, and RECs.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The increase of $99 million for the three months ended March 31, 2025 compared to the same period in 2024 in **Purchased power and fuel expense** is offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended March 31, 2025 Increase (Decrease)
Credit loss expense	$ 17
Labor, other benefits, contracting and materials	9
BSC costs	1
Pension and non-pension postretirement benefit expense	1
Storm-related costs	(4)
Other	(1)
	23
Regulatory required programs	11
Total increase	$ 34

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2025
	Increase (Decrease)
Depreciation and amortization[(a)]	$ 7
Regulatory asset amortization	(2)
Total increase	$ 5

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Taxes other than income taxes increased by $9 million for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to higher Pennsylvania gross receipts tax.

Interest expense, net increased $8 million for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to an increase in interest rates and higher outstanding debt.

Effective income tax rates were 5.0% and 6.3% for the three months ended March 31, 2025 and 2024, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations — BGE

	Three Months Ended March 31, 2025	2024	Favorable (Unfavorable) Variance
Operating revenues	$ 1,554	$ 1,297	$ 257
Operating expenses			
Purchased power and fuel	609	464	(145)
Operating and maintenance	305	264	(41)
Depreciation and amortization	164	150	(14)
Taxes other than income taxes	96	89	(7)

Total operating expenses	1,174	967	(207)
Operating income	380	330	50
Other income and (deductions)			
Interest expense, net	(58)	(50)	(8)
Other, net	9	8	1
Total other income and (deductions)	(49)	(42)	(7)
Income before income taxes	331	288	43
Income taxes	71	24	(47)
Net income	$ 260	$ 264	$ (4)

Three Months Ended March 31, 2025 Compared to Three Months Ended March 31, 2024**. Net Income** decreased $4 million primarily due to an increase in various operating expenses and an increase in interest expense, partially offset by favorable distribution rates.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2025		
	Increase (Decrease)		
	Electric	Gas	Total
Distribution	$ 33	$ 44	$ 77
Transmission	7	—	7
Other	2	(1)	1
	42	43	85
Regulatory required programs	88	84	172
Total increase	$ 130	$ 127	$ 257

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and customer usage. However, Operating revenues are not impacted by abnormal weather or usage per customer as a result of a monthly rate adjustment that provides for fixed distribution revenue per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

	At March 31,	
Number of Electric Customers	2025	2024
Residential	1,220,769	1,213,063
Small commercial & industrial	115,359	115,406
Large commercial & industrial	13,302	13,110
Public authorities & electric railroads	258	261
Total	1,349,688	1,341,840

	At March 31,	
Number of Natural Gas Customers	2025	2024
Residential	661,195	658,818
Small commercial & industrial	37,945	37,982
Large commercial & industrial	6,380	6,336
Total	705,520	703,136

Distribution Revenue increased for the three months ended March 31, 2025, compared to the same period in 2024, due to favorable impacts of the multi-year plans.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue increased for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to increases in underlying costs and capital investments.

Other Revenue includes revenue related to late payment charges, mutual assistance, off-system sales, and service application fees. Other Revenue remained relatively consistent for the three months ended March 31, 2025 compared to the same period in 2024.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as conservation, demand response, and the POLR mechanism. The riders are designed to provide full and current cost recovery, as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries as BGE remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, BGE acts as the billing agent and therefore does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from BGE, BGE is permitted to recover the electricity and natural gas procurement costs from customers and therefore records the amounts related to the electricity and/or natural gas in Operating revenues and Purchased power and fuel expense. BGE recovers electricity and natural gas procurement costs from customers with a slight mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

The increase of $145 million for the three months ended March 31, 2025 compared to the same period in 2024, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended March 31, 2025
	Increase (Decrease)

Labor, other benefits, contracting, and materials	12
BSC costs	3
Credit loss expense	2
Pension and non-pension postretirement benefits expense	1
Storm-related costs	(5)
Other	5
	18
Regulatory required programs[a]	23
Total increase	$ 41

(a) Increase due to the cost recovery associated with EmPOWER Maryland. Please refer to 2024 10-K Note 3 — Regulatory Matters for additional information.

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2025
	Increase
Depreciation and amortization	$ 2
Regulatory required programs[a]	6
Regulatory asset amortization	6
Total increase	$ 14

(a) Increase due to the cost recovery associated with EmPOWER Maryland. Please refer to 2024 10-K Note 3 — Regulatory Matters for additional information.

Interest expense, net increased by $8 million for the three months ended March 31, 2025 compared to the same period in 2024, primarily due to the issuance of debt in the second quarter of 2024.

Taxes other than income taxes increased by $7 million for the three months ended March 31, 2025 compared to the same period in 2024, primarily due to increased property taxes.

Effective income tax rates were 21.5% and 8.3% for the three months ended March 31, 2025 and 2024, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations — PHI

PHI's Results of Operations include the results of its three reportable segments, Pepco, DPL, and ACE. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services, and the costs are directly charged or allocated to the applicable subsidiaries. Additionally, the results of PHI's corporate operations include interest costs from various financing activities. All material intercompany accounts and transactions have been eliminated in consolidation. The following table sets forth PHI's GAAP consolidated Net income, by Registrant, for the three months ended March 31, 2025 compared to the same period in 2024. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024	Favorable (Unfavorable) Variance
PHI	$ 194	$ 168	$ 26
Pepco	97	75	22
DPL	69	66	3
ACE	31	29	2
Other[a]	(3)	(2)	(1)

(a) Primarily includes eliminating and consolidating adjustments, PHI's corporate operations, shared service entities, and other financing and investing activities.

***Three Months Ended March 31, 2025* *Compared to* *Three Months Ended March 31, 2024*. Net Income** increased by $26 million primarily due to favorable impacts from the Maryland and District of Columbia multi-year plans, higher DPL Delaware electric and gas DISC rates, higher transmission rates at Pepco and DPL, favorable weather conditions at DPL, partially offset by an increase in interest and depreciation expense at Pepco and DPL.

Results of Operations — Pepco

	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024	Favorable (Unfavorable) Variance
Operating revenues	$ 859	$ 759	$ 100
Operating expenses			
Purchased power	318	281	(37)
Operating and maintenance	159	150	(9)
Depreciation and amortization	105	107	2
Taxes other than income taxes	113	102	(11)
Total operating expenses	695	640	(55)
Gain on sales of assets	(1)	—	(1)
Operating income	163	119	44
Other income and (deductions)			
Interest expense, net	(52)	(45)	(7)
Other, net	11	15	(4)
Total other income and (deductions)	(41)	(30)	(11)
Income before income taxes	122	89	33
Income taxes	25	14	(11)
Net income	$ 97	$ 75	$ 22

***Three Months Ended March 31, 2025 Compared to Three Months Ended March 31, 2024*. Net Income** increased by $22 million primarily due to favorable impacts from the Maryland and District of Columbia multi-year plans and higher transmission rates, partially offset by an increase in interest and depreciation expense.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2025 Increase (Decrease)
Distribution	$ 45
Transmission	6
Other	(3)
	48
Regulatory required programs	52
Total increase	$ 100

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in both Maryland and the District of Columbia are not intended to be impacted by abnormal weather or usage per customer as a result of a BSA that provides for a fixed distribution charge per customer class in the District of Columbia and per customer by customer class in Maryland. Therefore, changes in the number of customers only impacts Operating revenues in Maryland.

Number of Electric Customers in Maryland	At March 31, 2025	At March 31, 2024
Residential	557,672	552,215
Small commercial & industrial	30,555	30,760
Large commercial & industrial	18,986	18,944
Public authorities & electric railroads	177	179
Total	607,390	602,098

Distribution Revenue increased for the three months ended March 31, 2025 compared to the same period in 2024 primarily due to favorable impacts of the Maryland and District of Columbia multi-year plans and customer growth in Maryland.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue increased for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to increases in underlying costs and capital investments.

Other Revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DC PLUG, and SOS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, as Pepco remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, Pepco acts as the billing agent and therefore, Pepco does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from Pepco, Pepco is permitted to recover the electricity and REC procurement costs from customers and therefore records the amounts related to the electricity and RECs in Operating revenues and Purchased power expense. Pepco recovers electricity and REC procurement costs from customers with a slight mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

The increase of $37 million for the three months ended March 31, 2025, compared to the same period in 2024, in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended March 31, 2025
	(Decrease) Increase
Labor, other benefits, contracting and materials	$ (6)
Credit loss expense	(5)
BSC and PHISCO costs	(2)
Other	5
	(8)
Regulatory required programs[a]	17
Total increase	$ 9

(a) Increase primarily due to the cost recovery associated with EmPOWER Maryland. Please refer to 2024 10-K Note 3 — Regulatory Matters for additional information.

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2025
	Increase (Decrease)
Depreciation and amortization[(a)]	$ 7
Regulatory asset amortization	1
Regulatory required programs[(b)]	(10)
Total decrease	$ (2)

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.
(b) Decrease includes the cost recovery associated with EmPOWER Maryland. Please refer to 2024 10-K Note 3 — Regulatory Matters additional information.

Taxes other than income taxes increased $11 million for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to increases in utility taxes, which are offset in revenues, and property taxes.

Effective income tax rates were 20.5% and 15.7% for the three months ended March 31, 2025 and 2024. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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Results of Operations — DPL

	Three Months Ended March 31, 2025	Three Months Ended March 31, 2024	Favorable (Unfavorable) Variance
Operating revenues	$ 548	$ 491	$ 57
Operating expenses			
Purchased power and fuel	247	215	(32)
Operating and maintenance	106	95	(11)
Depreciation and amortization	63	61	(2)
Taxes other than income taxes	21	20	(1)
Total operating expenses	437	391	(46)
Operating income	111	100	11
Other income and (deductions)			
Interest expense, net	(25)	(22)	(3)
Other, net	4	5	(1)
Total other income and (deductions)	(21)	(17)	(4)
Income before income taxes	90	83	7
Income taxes	21	17	(4)
Net income	$ 69	$ 66	$ 3

***Three Months Ended March 31, 2025 Compared to Three Months Ended March 31, 2024*. Net income** increased $3 million primarily due to favorable weather conditions at Delaware electric and natural gas service territories, higher Delaware electric and gas DSIC rates, and higher transmission rates, partially offset by an increase in depreciation and interest expense.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2025 Increase Electric	Gas	Total
Weather	$ 4	$ 2	$ 6
Volume	—	3	3
Distribution	5	1	6
Transmission	3	—	3
	12	6	18
Regulatory required programs	30	9	39
Total increase	$ 42	$ 15	$ 57

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in Maryland are not impacted by abnormal weather or usage per customer as a result of a BSA that provides for a fixed distribution charge per customer by customer class. While Operating revenues from electric distribution customers in Maryland are not intended to be impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

Weather. The demand for electricity and natural gas in Delaware is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended March 31, 2025 compared to the same period in 2024, Operating revenues related to weather increased due to favorable weather conditions in DPL's Delaware electric and natural gas service territories.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL's Delaware electric service territory and a 30-year period in DPL's Delaware natural gas service territory. The changes in heating and cooling degree days in DPL's Delaware service territory for the three months ended March 31, 2025, compared to same period in 2024 and normal weather consisted of the following:

	Three Months Ended March 31,			% Change	
Delaware Electric Service Territory	2025	2024	Normal	2025 vs. 2024	2025 vs. Normal
Heating Degree-Days	2,399	2,204	2,420	8.8 %	(0.9)%
Cooling Degree-Days	9	—	1	— %	800.0 %

	Three Months Ended March 31,			% Change	
Delaware Natural Gas Service Territory	2025	2024	Normal	2025 vs. 2024	2025 vs. Normal
Heating Degree-Days	2,399	2,204	2,454	8.8 %	(2.2)%

Volume, exclusive of the effects of weather, increased for the three months ended March 31, 2025 compared to the same period in 2024, primarily due to an increase in customer usage and customer growth.

Electric Retail Deliveries to Delaware Customers (in GWhs)	Three Months Ended March 31, 2025	2024	% Change	Weather - Normal % Change [(b)]
Residential	930	857	8.5 %	1.9 %
Small commercial & industrial	354	339	4.4 %	2.0 %
Large commercial & industrial	690	718	(3.9)%	(4.7)%
Public authorities & electric railroads	7	7	— %	1.9 %
Total electric retail deliveries[(a)]	1,981	1,921	3.1 %	(0.5)%

Number of Total Electric Customers (Maryland and Delaware)	At March 31, 2025	2024
Residential	491,907	486,950
Small commercial & industrial	64,999	64,338
Large commercial & industrial	1,251	1,260
Public authorities & electric railroads	617	593
Total	558,774	553,141

(a) Reflects delivery volumes from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 20-year average.

Natural Gas Retail Deliveries to Delaware Customers (in mmcf)	Three Months Ended March 31, 2025	2024	% Change	Weather - Normal % Change [(b)]
Residential	4,590	3,913	17.3 %	8.7 %
Small commercial & industrial	1,970	1,717	14.7 %	5.1 %
Large commercial & industrial	428	428	— %	— %
Transportation	2,106	1,960	7.4 %	2.9 %

Total natural gas deliveries[(a)]	9,094	8,018	13.4 %	6.1 %

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Number of Delaware Natural Gas Customers	At March 31, 2025	2024
Residential	131,716	130,427
Small commercial & industrial	10,254	10,182
Large commercial & industrial	15	16
Transportation	161	163
Total	142,146	140,788

(a) Reflects delivery volumes from customers purchasing natural gas directly from DPL and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Distribution Revenue increased for the three months ended March 31, 2025 compared to the same period in 2024 primarily due to higher electric and natural gas DSIC rates in Delaware that became effective January 2025.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. During the three months ended March 31, 2025 compared to the same period in 2024, transmission revenue increased due to increases in underlying costs and capital investments.

Other Revenue includes rental revenue, service connection fees, and mutual assistance revenues.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DE Renewable Portfolio Standards, SOS procurement and administrative costs, and GCR costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. All customers have the choice to purchase electricity from competitive electric generation suppliers; however, only certain commercial and industrial customers have the choice to purchase natural gas from competitive natural gas suppliers. Customer choice programs do not impact the volume of deliveries as DPL remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, DPL either acts as the billing agent or the competitive supplier separately bills its own customers, and therefore does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from DPL, DPL is permitted to recover the electricity, natural gas, and REC procurement costs from customers and therefore records the amounts related to the electricity, natural gas, and RECs in Operating revenues and Purchased power and fuel expense. DPL recovers electricity and REC procurement costs from customers with a slight mark-up, and natural gas costs without mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

The increase of $32 million for the three months ended March 31, 2025, compared to the same period in 2024, respectively, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended March 31, 2025
	Increase (Decrease)
Credit loss expense	$ 4
BSC and PHISCO costs	1
Storm-related costs	(3)
Labor and contracting	(3)
Other	1
	—
Regulatory required programs[(a)]	11
Total increase	$ 11

(a) Increase primarily due to the cost recovery associated with EmPOWER Maryland. Please refer to 2024 10-K Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2025
	Increase (Decrease)
Depreciation and amortization[(a)]	$ 4
Regulatory asset amortization	—
Regulatory required programs[(b)]	(2)
Total increase	$ 2

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.
(b) Decrease includes the cost recovery associated with EmPOWER Maryland. Please refer to 2024 10-K Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information

Effective income tax rates were 23.3% and 20.5% for the three months ended March 31, 2025 and 2024, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations — ACE

	Three Months Ended March 31, 2025	2024	Favorable (Unfavorable) Variance
Operating revenues	$ 373	$ 358	$ 15
Operating expenses			
Purchased power	157	140	(17)
Operating and maintenance	90	87	(3)
Depreciation and amortization	64	74	10
Taxes other than income taxes	2	2	—
Total operating expenses	313	303	(10)
Operating income	60	55	5
Other income and (deductions)			
Interest expense, net	(21)	(20)	(1)
Other, net	3	5	(2)
Total other income and (deductions)	(18)	(15)	(3)
Income before income taxes	42	40	2
Income taxes	11	11	—
Net income	$ 31	$ 29	$ 2

Three Months Ended March 31, 2025 Compared to Three Months Ended March 31, 2024**. Net income** remained relatively consistent.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2025 Increase (Decrease)
Distribution	$ 2
Transmission	(2)
	—
Regulatory required programs	15
Total increase	$ 15

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in New Jersey are not intended to be impacted by abnormal weather or usage per customer as a result of the CIP which became effective, prospectively, in the third quarter of 2021. The CIP compares current distribution revenues by customer class to approved target revenues established in ACE’s most recent distribution base rate case. The CIP is calculated annually, and recovery is subject to certain conditions, including an earnings test and ceilings on customer rate increases. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

	At March 31,	
Number of Electric Customers	**2025**	**2024**
Residential	508,354	505,793
Small commercial & industrial	62,861	62,704
Large commercial & industrial	2,824	2,893
Public authorities & electric railroads	723	728
Total	574,762	572,118

Distribution Revenue remained relatively consistent for the three months ended March 31, 2025 compared to the same period in 2024.

Transmission Revenues Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue remained relatively consistent for the three months ended March 31, 2025 compared to the same period in 2024.

Other Revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, Societal Benefits Charge, Transition Bonds, and BGS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, as ACE remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, ACE acts as the billing agent and therefore, ACE does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from ACE, ACE is permitted to recover the electricity, ZEC, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power expense related to the electricity, ZECs, and RECs.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

The increase of $17 million for the three months ended March 31, 2025 , respectively, compared to the same period in 2024 in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

The changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended March 31, 2025
	Increase (Decrease)
Storm-related costs	$ 1
Credit Loss Expense	1
BSC and PHISCO costs	(1)
Labor and contracting	(2)
Other	(3)
	(4)
Regulatory required programs	7
Total increase	$ 3

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2025
	Increase (Decrease)
Depreciation and amortization[a]	$ 2
Regulatory asset amortization	(3)
Regulatory required programs	(9)
Total decrease	$ (10)

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Effective income tax rates were 26.2% and 27.5% for the three months ended March 31, 2025 and 202, respectively. See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Liquidity and Capital Resources (All Registrants)

All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations, as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each of the Registrants annually evaluates its financing plan, dividend practices, and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, including construction expenditures, retire debt, pay dividends, and fund pension and OPEB obligations. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, the Utility Registrants operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to credit facilities with aggregate bank commitments of $4.0 billion. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings, and to issue letters of credit. See the "Credit Matters and Cash Requirements" section below for additional information. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

The Utility Registrants' cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE, and DPL, gas distribution services. The Utility Registrants' distribution services are provided to an established and diverse base of retail customers. The Utility Registrants' future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, and their ability to achieve operating cost reductions. Additionally, ComEd is required to purchase CMCs from participating nuclear-powered generating facilities for a five-year period that began in June 2022, and all of its costs of doing so will be recovered through a rider. The price to be paid for each CMC is established through a competitive bidding process. ComEd will provide net payments to, or collect net payments from, customers for the difference between customer credits issued and the credit to be received from the participating nuclear-powered generating facilities. ComEd's cash flows are affected by the establishment of CMC prices and the timing of recovering costs through the CMC regulatory asset.

See Note 3 — Regulatory Matters of the 2024 Form 10-K and Notes 2 — Regulatory Matters and 11 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the change in cash flows from operating activities for the three months ended March 31, 2025 and 2024 by Registrant:

Increase (decrease) in cash flows from operating activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income (loss)	$ 250	$ 109	$ 117	$ (4)	$ 26	$ 22	$ 3	$ 2
Adjustments to reconcile net income to cash:								
Non-cash operating activities	408	158	31	129	65	31	14	14
Collateral received, net	37	(3)	12	1	27	11	9	5
Income taxes	38	51	13	7	1	3	3	—
Pension and non-pension postretirement benefit contributions	(181)	(184)	(7)	(9)	30	—	—	4
Regulatory assets and liabilities, net	(166)	(239)	47	14	28	7	3	19
Changes in working capital and other assets and liabilities	(178)	(93)	(60)	(33)	(64)	(65)	(27)	40
Increase (decrease) in cash flows from operating activities	$ 208	$ (201)	$ 153	$ 105	$ 113	$ 9	$ 5	$ 84

Changes in the Registrants' cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. Significant operating cash flow impacts for the Registrants for the three months ended March 31, 2025 and 2024 were as follows:

- See Note 14 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statements of Cash Flows for additional information on **non-cash operating activities**.

- Changes in **collateral** depended upon whether the Registrant was in a net mark-to-market liability or asset position, and collateral may have been required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differed depending on whether the transactions were on an exchange or in the over-the-counter markets. Changes in collateral for the Registrants are dependent upon the credit exposure of procurement contracts that may require suppliers to post collateral. The amount of cash collateral received from external counterparties remained relatively consistent comparing the three months ended March 31, 2025 to the three months ended March 31, 2024. See Note 8 — Derivative Financial Instruments for additional information.
- See Note 6 — Income Taxes of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statements of Cash Flows for additional information on **income taxes**.
- Changes in **Pension and non-pension postretirement benefit contributions** relates to Exelon's increased contributions to the Qualified Plans during the three months ended March 31, 2025. See Note 14 — Retirement Benefits of the 2024 Form 10-K for additional information.
- Changes in **regulatory assets and liabilities, net,** are due to the timing of cash payments for costs recoverable, or cash receipts for costs recovered, under our regulatory mechanisms differing from the recovery period of those costs. Included within the changes is energy efficiency spend for ComEd of $84 million and $80 million for the three months ended March 31, 2025 and 2024, respectively. Also included within the changes is energy efficiency and demand response programs spend for BGE, Pepco, DPL and ACE of $22 million, $6 million, $3 million, and $5 million for the three months ended March 31, 2025 and $28 million, $10 million, $4 million, and $8 million for the three months ended March 31, 2024, respectively. PECO had no energy efficiency and demand response programs spend recorded to the regulatory asset for the three months ended March 31, 2025 and 2024. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

- **Changes in working capital and other assets and liabilities** for the Utility Registrants and Exelon Corporate totaled $(238) million and $(178) million, respectively. The change in working capital and other noncurrent assets and liabilities for Exelon Corporate and the Utility Registrants is dependent upon the normal course of operations for all Registrants. For ComEd, it is also dependent upon whether the participating nuclear-powered generating facilities are owed money from ComEd as a result of the established pricing for CMCs. For the three months ended March 31, 2025, the established pricing resulted in both a receivable from, and payable to, nuclear-powered generating facilities. The change in receivable from nuclear-powered generating facilities, and the change in payable to nuclear-powered generating facilities, are reflected as a change in accounts receivable and a change in accounts payable and accrued expenses, respectively, within the cash flows from operations.

Cash Flows from Investing Activities

The following table provides a summary of the change in cash flows from investing activities for the three months ended March 31, 2025 and 2024 by Registrant:

(Decrease) increase in cash flows from investing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	$ (179)	$ 4	$ (63)	$ (82)	$ (60)	$ (11)	$ (22)	$ (16)
Proceeds from sales of assets	(2)	—	—	—	—	—	—	—
Changes in intercompany money pool	—	—	—	—	—	134	(12)	—
Other investing activities	6	—	—	(5)	—	—	—	—

(Decrease) increase in cash flows from investing activities	$ (175)	$ 4	$ (63)	$ (87)	$ (60)	$ 123	$ (34)	$ (16)

Significant investing cash flow impacts for the Registrants for three months ended March 31, 2025 and 2024 were as follows:

- Changes in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. See the "Credit Matters and Cash Requirements" section below for additional information on projected capital expenditure spending for the Utility Registrants.
- Changes in **intercompany money pool** are driven by short-term borrowing needs. Refer to more information regarding the intercompany money pool below.

Cash Flows from Financing Activities

The following table provides a summary of the change in cash flows from financing activities for the three months ended March 31, 2025 and 2024 by Registrant:

Increase (decrease) in cash flows from financing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	$ (458)	$ 183	$ (27)	$ (8)	$ (136)	$ (68)	$ (81)	$ 13
Long-term debt, net	701	—	—	—	(100)	(75)	(50)	25
Changes in intercompany money pool	—	—	—	—	3	—	—	(122)
Issuance of common stock	173	—	—	—	—	—	—	—
Dividends paid on common stock	(22)	(9)	(37)	(6)	—	(15)	(1)	2
Distributions to member	—	—	—	—	(14)	—	—	—
Contributions from parent/member	—	48	(17)	—	(135)	(94)	(55)	13
Other financing activities	9	(1)	—	—	13	10	—	—
Increase (decrease) in cash flows from financing activities	$ 403	$ 221	$ (81)	$ (14)	$ (369)	$ (242)	$ (187)	$ (69)

Significant financing cash flow impacts for the Registrants for the three months ended March 31, 2025 and 2024 were as follows:

- **Changes in short-term borrowings, net**, is driven by repayments on and issuances of notes due in less than 365 days. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on short-term borrowings for the Registrants.
- **Long-term debt, net**, varies due to debt issuances and redemptions each year. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on debt issuances. Refer to the "Debt" section below for additional information.
- **Changes in intercompany money pool** are driven by short-term borrowing needs. Refer below for more information regarding the intercompany money pool.
- **Issuance of common stock** relates to issuances of Exelon common stock during the first quarter of 2025. See Note 12 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.
- Exelon's ability to pay **dividends** on its common stock depends on the receipt of dividends paid by

its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. See Note 18 — Commitments and Contingencies of the 2024 Form 10-K for additional information on dividend restrictions. See below for quarterly dividends declared.

Debt

See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt issuances.

During the three months ended March 31, 2025, no long-term debt was retired and/or redeemed.

Dividends

Quarterly dividends declared by the Exelon Board of Directors during the three months ended March 31, 2025 and for the second quarter of 2025 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share [(a)]
First Quarter 2025	February 12, 2025	February 24, 2025	March 14, 2025	$ 0.4000
Second Quarter 2025	April 29, 2025	May 12, 2025	June 13, 2025	$ 0.4000

(a) Exelon's Board of Directors approved an updated dividend policy for 2025. The 2025 quarterly dividend will be $0.40 per share.

Credit Matters and Cash Requirements

The Registrants fund liquidity needs for capital investment, working capital, energy hedging, and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets, and large, diversified credit facilities. The credit facilities include $4.0 billion in aggregate total commitments of which $3.4 billion was available to support additional commercial paper as of March 31, 2025, and of which no financial institution has more than 6.2% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper markets and had availability under their revolving credit facilities during the three months ended March 31, 2025 to fund their short-term liquidity needs, when necessary. Exelon Corporate and the Utility Registrants each have a 5-year revolving credit facility. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. The Registrants

have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising, and merger activity. See PART I. ITEM 1A. RISK FACTORS of the 2024 Form 10-K for additional information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flows from operating activities, access to credit markets, and their credit facilities provide sufficient liquidity to support the estimated future cash requirements.

On August 4, 2022, Exelon executed an equity distribution agreement ("Equity Distribution Agreement"), with certain sales agents and forward sellers and certain forward purchasers, establishing an ATM equity distribution program under which it may offer and sell shares of its Common stock, having an aggregate gross sales price of up to $1.0 billion. Exelon has no obligation to offer or sell any shares of Common stock under the Equity Distribution Agreement and may, at any time, suspend or terminate offers and sales under the Equity Distribution Agreement.

During the first quarter 2025, Exelon issued approximately 4.0 million shares of Common stock at an average gross price of $43.42 per share. The net proceeds from the issuance were $173 million, which were used for general corporate purposes.

In the first quarter of 2025, Exelon entered into two separate forward sale agreements for 1.7 million shares and 4.0 million shares of Common stock, with an initial forward price of $42.81 and $43.42 per share, respectively. The forward sale agreements require Exelon to, at its election prior to December 15, 2025, either (i) physically settle the transactions by issuing shares of its Common stock to the forward counterparties in exchange for net proceeds at the then-applicable forward sale price specified by the agreements or (ii) net settle the transactions in whole or in part through the delivery to the forward counterparties or receipt from the forward counterparties of cash or shares in accordance with the provisions of the agreements. No amounts have been or will be recorded on Exelon's balance sheet with respect to the equity offerings until the equity forward sale agreements have been settled. Each initial forward sale price is subject to adjustment on a daily basis based on a floating interest rate factor and will decrease by other fixed amounts specified in the agreements. Until settlement of the equity forward, earnings per share dilution resulting from the agreement, if any, will be determined under the treasury stock method. For the three months ended March 31, 2025, approximately 5.6 million shares under the forward sale agreements were not included in the calculation of diluted earnings per share because their effect would have been antidilutive.

Inclusive of the impact of the forward sale agreements, $283 million of Common stock remained available for sale pursuant to the ATM program as of March 31, 2025.

The following table presents the incremental collateral that each Utility Registrant would have been required to provide in the event each Utility Registrant lost its investment grade credit rating at March 31, 2025 and available credit facility capacity prior to any incremental collateral at March 31, 2025:

	PJM Credit Policy Collateral	Other Incremental Collateral Required [(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 13	$ —	$ 638
PECO	—	45	596
BGE	—	51	338
Pepco	—	—	298
DPL	—	15	300
ACE	—	—	300

(a) Represents incremental collateral related to natural gas procurement contracts.

Capital Expenditure Spending

As of March 31, 2025, the most recent estimates of capital expenditures for plant additions and improvements for 2025 are as follows:

(In millions)	Transmission	Distribution	Gas	Total [(a)]
Exelon	N/A	N/A	N/A	$ 8,900
ComEd	950	2,250	N/A	3,200
PECO	200	1,300	375	1,875
BGE	700	625	525	1,850
PHI	650	1,400	100	2,150
Pepco	250	700	N/A	950
DPL	175	300	75	550
ACE	200	250	N/A	450

(a) Numbers rounded to the nearest $25M and may not sum due to rounding.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Retirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation, and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions reflect a funding strategy to make annual contributions with the objective of achieving 100% funded status on an ABO basis over time. This funding strategy helps minimize volatility of future period required pension contributions. Exelon's estimated annual qualified pension contributions will be $275 million in 2025. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While OPEB plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its OPEB plans, including liabilities management, levels of benefit claims paid, and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery).

To the extent interest rates decline significantly or the pension and OPEB plans earn less than the expected asset returns, annual pension contribution requirements in future years could increase. Conversely, to the extent interest rates increase significantly or the pension and OPEB plans earn greater than the expected asset returns, annual pension and OPEB contribution requirements in future years could decrease. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

See Note 14 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements of the 2024 Form 10-K for additional information on pension and OPEB contributions.

Credit Facilities

Exelon Corporate, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. PECO meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. Pepco, DPL, and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the PHI intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' credit facilities and short term borrowing activity.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that

Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 8 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

The credit ratings for ComEd, BGE, PHI, Pepco, DPL, and ACE did not change for the three months ended March 31, 2025. On January 17, 2025, Fitch Ratings affirmed and withdrew the long-term and short-term issuer default ratings along with individual securities ratings of the Registrants for commercial reasons. On February 7, 2025, S&P raised its long-term issuer credit rating for Exelon and PECO from 'BBB+' to 'A-', and raised its rating on Exelon's senior unsecured debt from 'BBB' to 'BBB+'. S&P also affirmed its short-term issuer and commercial paper rating for Exelon and PECO of 'A-2'.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of March 31, 2025 are presented in the following table:

Exelon Intercompany Money Pool	During the Three Months Ended March 31, 2025 Maximum Contributed	During the Three Months Ended March 31, 2025 Maximum Borrowed	At March 31, 2025 Contributed (Borrowed)
Exelon Corporate	$ 578	$ —	$ 295
PECO	—	(253)	—
BSC	—	(378)	(281)
PHI Corporate	—	(85)	(74)
PCI	60	—	60

PHI Intercompany Money Pool	During the Three Months Ended March 31, 2025 Maximum Contributed	During the Three Months Ended March 31, 2025 Maximum Borrowed	At March 31, 2025 Contributed (Borrowed)
Pepco	$ 1	$ —	$ —
DPL	12	(1)	12
ACE	—	(12)	(12)

Shelf Registration Statements

On February 21, 2024, PECO and BGE, as co-registrants, filed with the SEC a standalone automatically effective shelf registration statement, unlimited in amount, which can be used to issue PECO and BGE debt securities through the expiration date of February 20, 2027. On February 13, 2025, as most recently amended on March 27, 2025, Exelon Corporation and ComEd, as co-registrants filed a shelf registration statement with the SEC ("Exelon and ComEd Shelf Registration") for authorization of up to $12,575 million in additional security registration, to be used to issue Exelon Corporate debt securities and equity securities, as well as ComEd debt securities. The Exelon and ComEd Shelf Registration was declared effective by the SEC on April 8, 2025, and is

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effective through April 8, 2028. The ability of Exelon Corporation, ComEd, PECO and BGE to sell securities off their corresponding registration Statements, or to access the private placement markets, will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Pepco, DPL and ACE periodically issue securities through the private placement markets. Pepco, DPL and ACE's ability to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, current financial condition, securities ratings and market conditions.

Regulatory Authorizations

The Utility Registrants are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	At March 31, 2025					
	Short-term Financing Authority			Remaining Long-term Financing Authority		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd	FERC	December 31, 2025	$ 2,500	ICC	January 1, 2027 & May 1, 2027	$ 2,318
PECO	FERC	December 31, 2025	1,500	PAPUC	December 31, 2027	2,900
BGE[(b)]	FERC	December 31, 2025	700	MDPSC	N/A	2,500
Pepco[(a)]	FERC	December 31, 2025	500	MDPSC / DCPSC	December 31, 2025	175
DPL[(a)]	FERC	December 31, 2025	500	MDPSC / DEPSC	December 31, 2025	250
ACE	NJBPU	December 31, 2025	350	NJBPU	December 31, 2026	775

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(a) The financing authority filed with MDPSC does not have an expiration date, while the financing authority filed with DCPSC and DEPSC have an expiration date of December 31, 2025.

(b) On February 20, 2025, BGE received approval from the MDPSC for $2.2 billion in additional long-term financing authority. The additional financing authority has an effective date of February 20, 2025.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

The Registrants hold commodity and financial instruments that are exposed to the following market risks:

- Commodity price risk, which is discussed further below.
- Counterparty credit risk associated with non-performance by counterparties on executed derivative instruments and participation in all, or some of the established, wholesale spot energy markets that are administered by PJM. The credit policies of PJM may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants. See Note 8 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of counterparty credit risk related to derivative instruments.
- Equity price and interest rate risk associated with Exelon's pension and OPEB plan trusts. See Note 7 — Retirement Benefits of the 2024 Form 10-K for additional information.
- Interest rate risk associated with changes in interest rates for the Registrants' outstanding long-term debt. This risk is significantly reduced as substantially all of the Registrants' outstanding debt has fixed interest rates. There is inherent interest rate risk related to refinancing maturing debt by issuing new long-term debt. The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. See Note 9 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. In addition, Exelon may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. See Note 8 – Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants operate primarily under cost-based rate regulation limiting exposure to the effects of market risk. Hedging programs are utilized to reduce exposure to energy and natural gas price volatility and have no direct earnings impacts as the costs are fully recovered through regulatory-approved recovery mechanisms.

Exelon manages these risks through risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. Risk management issues are reported to Exelon's Executive Committee, the Risk Management Committees of each Utility Registrant, and the Audit and Risk Committee of Exelon's Board of Directors.

Commodity Price Risk

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the total amount of energy Exelon purchases differs from the amount of energy it has contracted to sell, Exelon is exposed to market fluctuations in commodity prices. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity and natural gas.

ComEd entered into 20-year floating-to-fixed renewable energy swap contracts beginning in June 2012, which are considered an economic hedge and have changes in fair value recorded to an offsetting regulatory asset or liability. ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which are considered derivatives and qualify for NPNS, and as a result are accounted for on an accrual basis of accounting. PECO, BGE, Pepco, DPL, and ACE have contracts to procure electric supply that are executed through a competitive procurement process. PECO, BGE, Pepco, DPL, and ACE have certain full requirements contracts, which are considered derivatives and qualify for NPNS, and as a result are accounted for on an accrual basis of accounting. Other full requirements contracts are not derivatives.

PECO, BGE, and DPL also have executed derivative natural gas contracts, which qualify for NPNS, to hedge their long-term price risk in the natural gas market. The hedging programs for natural gas procurement have no direct impact on their financial statements.

For additional information on these contracts, see Note 8 — Derivative Financial Instruments and Note 10 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements.

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The following table presents the maturity and source of fair value for Exelon's and ComEd's mark-to-market commodity contract net liabilities. These net liabilities are associated with ComEd's floating-to-fixed energy swap contracts with unaffiliated suppliers. The table provides two fundamental pieces of information. First, the table provides the source of fair value used in determining the carrying amount of Exelon's and ComEd's total mark-to-market net liabilities. Second, the table shows the maturity, by year, of Exelon's and ComEd's commodity contract net liabilities giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 10 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

	Maturities Within						
Commodity derivative contracts [(a)]:	**2025**	**2026**	**2027**	**2028**	**2029**	**2030 and Beyond**	**Total Fair Value**
Prices based on model or other valuation methods (Level 3)	$ (17)	$ (18)	$ (21)	$ (22)	$ (21)	$ (52)	$ (151)

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(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

ITEM 4. CONTROLS AND PROCEDURES

During the first quarter of 2025, each of the Registrants' management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing, and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by the Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to that Registrant's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated, and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of March 31, 2025, the principal executive officer and principal financial officer of each of the Registrants concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. There were no changes in internal control over financial reporting during the first quarter of 2025 that materially affected, or are reasonably likely to materially affect, any of the Registrants' internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of the 2024 Form 10-K, (b) Notes 3 — Regulatory Matters and 18 — Commitments and Contingencies of the 2024 Form 10-K, and (c) Notes 2 — Regulatory Matters and 11 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

ITEM 1A. RISK FACTORS

Risks Related to All Registrants

At March 31, 2025, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2024 Form 10-K in ITEM 1A. RISK FACTORS.

ITEM 5. OTHER INFORMATION

All Registrants

None of our officers or directors, as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted, modified, or terminated a "Rule 10b5-1 trading arrangement" or a "non-Rule 10b5-1 trading arrangement," as defined in Item 408 of Regulation S-K, during the three months ended March 31, 2025.

ITEM 6. EXHIBITS

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable Registrant and its subsidiaries on a consolidated basis, and the applicable Registrant agrees to furnish a copy of any such instrument to the Commission upon request.

(4) Instruments Defining the Rights of Securities Holders, Including Indentures

Exelon Corporation

Exhibit No.	Description	Location
4-1	Third Supplemental Indenture, dated as of February 1, 2025, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated February 19, 2025, Exhibit 4.2
4-2	Eighth Supplemental Indenture, dated as of February 1, 2025, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated February 21, 2025, Exhibit 4.2

Atlantic City Electric Company

Exhibit No.	Description	Location
4-3	ACE Supplemental Indenture to the Mortgage and Deed of Trust, dated as of March 1, 2025	File No. 001-03559, Form 8-K dated March 26, 2025, Exhibit 4.2

Delmarva Power & Light Company

Exhibit No.	Description	Location
4-4	DPL Supplemental Indenture to the Mortgage and Deed of Trust, dated as of March 1, 2025	File No. 001-01405, Form 8-K dated March 26, 2025, Exhibit 4.4

Potomac Electric Power Company

Exhibit No.	Description	Location
4-5	Pepco Supplemental Indenture to the Mortgage and Deed of Trust, dated as of March 1, 2025	File No. 001-01072, Form 8-K dated March 26, 2025, Exhibit 4.6

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2025 filed by the following officers for the following companies:

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Exelon Corporation

Exhibit No.	Description
31-1	Filed by Calvin G. Butler, Jr. for Exelon Corporation
31-2	Filed by Jeanne M. Jones for Exelon Corporation

Commonwealth Edison Company

Exhibit No.	Description
31-3	Filed by Gil C. Quiniones for Commonwealth Edison Company
31-4	Filed by Joshua S. Levin for Commonwealth Edison Company

PECO Energy Company

Exhibit No.	Description
31-5	Filed by David M. Velazquez for PECO Energy Company
31-6	Filed by Marissa E. Humphrey for PECO Energy Company

Baltimore Gas and Electric Company

Exhibit No.	Description
31-7	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
31-8	Filed by Michael J. Cloyd for Baltimore Gas and Electric Company

Pepco Holdings LLC

Exhibit No.	Description
31-9	Filed by J. Tyler Anthony for Pepco Holdings LLC
31-10	Filed by David M. Vahos for Pepco Holdings LLC

Potomac Electric Power Company

Exhibit No.	Description
31-11	Filed by J. Tyler Anthony for Potomac Electric Power Company
31-12	Filed by David M. Vahos for Potomac Electric Power Company

Delmarva Power & Light Company

Exhibit No.	Description
31-13	Filed by J. Tyler Anthony for Delmarva Power & Light Company
31-14	Filed by David M. Vahos for Delmarva Power & Light Company

Atlantic City Electric Company

Exhibit No.	Description
31-15	Filed by J. Tyler Anthony for Atlantic City Electric Company
31-16	Filed by David M. Vahos for Atlantic City Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes-Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2025 filed by the following officers for the following companies:

Table of Contents

Exelon Corporation

Exhibit No.	Description
32-1	Filed by Calvin G. Butler, Jr. for Exelon Corporation
32-2	Filed by Jeanne M. Jones for Exelon Corporation

Commonwealth Edison Company

Exhibit No.	Description
32-3	Filed by Gil C. Quiniones for Commonwealth Edison Company
32-4	Filed by Joshua S. Levin for Commonwealth Edison Company

PECO Energy Company

Exhibit No.	Description
32-5	Filed by David M. Velazquez for PECO Energy Company
32-6	Filed by Marissa E. Humphrey for PECO Energy Company

Baltimore Gas and Electric Company

Exhibit No.	Description
32-7	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
32-8	Filed by Michael J. Cloyd for Baltimore Gas and Electric Company

Pepco Holdings LLC

Exhibit No.	Description
32-9	Filed by J. Tyler Anthony for Pepco Holdings LLC
32-10	Filed by David M. Vahos for Pepco Holdings LLC

Potomac Electric Power Company

Exhibit No.	Description
32-11	Filed by J. Tyler Anthony for Potomac Electric Power Company
32-12	Filed by David M. Vahos for Potomac Electric Power Company

Delmarva Power & Light Company

Exhibit No.	Description
32-13	Filed by J. Tyler Anthony for Delmarva Power & Light Company
32-14	Filed by David M. Vahos for Delmarva Power & Light Company

Atlantic City Electric Company

Exhibit No.	Description
32-15	Filed by J. Tyler Anthony for Atlantic City Electric Company
32-16	Filed by David M. Vahos for Atlantic City Electric Company
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

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SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON CORPORATION

/s/ CALVIN G. BUTLER, JR.	/s/ JEANNE M. JONES
Calvin G. Butler, Jr.	Jeanne M. Jones
President, Chief Executive Officer (Principal Executive Officer) and Director	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ ROBERT A. KLECZYNSKI	
Robert A. Kleczynski	
Senior Vice President, Corporate Controller and Tax (Principal Accounting Officer)	

May 1, 2025

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

COMMONWEALTH EDISON COMPANY

/s/ GIL C. QUINIONES	/s/ JOSHUA S. LEVIN
Gil C. Quiniones	Joshua S. Levin
President, Chief Executive Officer (Principal Executive Officer) and Director	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ ERIN V. WHITE	
Erin V. White	
Director, Accounting (Principal Accounting Officer)	

May 1, 2025

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ MARISSA E. HUMPHREY
David M. Velazquez	Marissa E. Humphrey
President, Chief Executive Officer (Principal Executive Officer) and Director	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)

/s/ MARIANA HUFFORD

Mariana Hufford

Director, Accounting
(Principal Accounting Officer)

May 1, 2025

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ CARIM V. KHOUZAMI	/s/ MICHAEL J. CLOYD
Carim V. Khouzami	Michael J. Cloyd
President, Chief Executive Officer (Principal Executive Officer) and Director	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DAMON M. SCOLERI	
Damon M. Scoleri	
Director, Accounting (Principal Accounting Officer)	

May 1, 2025

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PEPCO HOLDINGS LLC

/s/ J. TYLER ANTHONY	/s/ DAVID M. VAHOS
J. Tyler Anthony	David M. Vahos
President, Chief Executive Officer (Principal Executive Officer) and Director	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JASON T. JONES	
Jason T. Jones	
Director, Accounting (Principal Accounting Officer)	

May 1, 2025

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Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

POTOMAC ELECTRIC POWER COMPANY

/s/ J. TYLER ANTHONY	/s/ DAVID M. VAHOS
J. Tyler Anthony	David M. Vahos
President, Chief Executive Officer (Principal Executive Officer) and Director	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JASON T. JONES	
Jason T. Jones	
Director, Accounting (Principal Accounting Officer)	

May 1, 2025

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Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

DELMARVA POWER & LIGHT COMPANY

/s/ J. TYLER ANTHONY	/s/ DAVID M. VAHOS
J. Tyler Anthony	David M. Vahos
President, Chief Executive Officer (Principal Executive Officer) and Director	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JASON T. JONES	
Jason T. Jones	
Director, Accounting (Principal Accounting Officer)	

May 1, 2025

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ATLANTIC CITY ELECTRIC COMPANY

/s/ J. TYLER ANTHONY	/s/ DAVID M. VAHOS
J. Tyler Anthony	David M. Vahos
President, Chief Executive Officer (Principal Executive Officer) and Director	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JASON T. JONES	
Jason T. Jones	
Director, Accounting (Principal Accounting Officer)	

May 1, 2025

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

AFFIDAVIT OF

JASON T. JONES

I, Jason T. Jones, am the Director, Accounting (Principal Accounting Officer) of Pepco Holdings LLC, a public utility holding company for Delmarva Power & Light Company (Delmarva) and Potomac Electric Power Company (Pepco). I hereby certify that to the best of my knowledge, information and belief, Delmarva and Pepco in good faith follow the processes and procedures set forth in the Pepco Holdings LLC Cost Allocation Manual (CAM) as well as the Commission's Asset Transfer policies contained in the Code of Maryland Regulations (COMAR) 20.40.02.05.

____
Jason T. Jones

May 28, 2025
____

DONNA LOCKMAN JACKSON
MY COMMISSION EXPIRES ON 03-10-2028
NOTARY PUBLIC
STATE OF DELAWARE

City of Newark)

State of Delaware)

Subscribed and sworn to me this 28rd day of May 2025 in the City of Newark, Delaware.

____
Notary Public

My Commission expires 03/10/2028