



May 30, 2023

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, 2022 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 2022 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 2022 Annual Report/Maryland Jurisdictional Electric Sales Statistics.
3. One (1) copy of the report of Energy Taxes and Property Taxes paid in 2022 to each municipal, county and state agency in Maryland.
4. One (1) copy of the Exelon First Quarter 2023 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 (779) 231-0975.

Sincerely,

Isaac Haertsch, CPA
Manager, External Financial Reporting, Exelon
Isaac.Haertsch@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) Delmarva Power & Light Company	Year/Period of Report End of: 2022 / Q4
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FERC FORM NO. 1 (REV. 02-04)

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.

Whenever (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, utilizing, 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 filed..."

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: 2022/ 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 Julie E. Giese	06 Title of Contact Person Director of Accounting	
07 Address of Contact Person (Street, City, State, Zip Code) 630 Martin Luther King Blvd, Wilmington, Delaware 19801		
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) 12/31/2022
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 Phillip S. Barnett	03 Signature Phillip S. Barnett	04 Date Signed (Mo, Da, Yr) 03/30/2023
02 Title SVP, CFO & Treasurer		
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: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106	
7	Important Changes During the Year	108	
8	Comparative Balance Sheet	110	
9	Statement of Income for the Year	114	
10	Statement of Retained Earnings for the Year	118	
12	Statement of Cash Flows	120	
12	Notes to Financial Statements	122	
13	Statement of Accum Other Comp Income, Comp Income, and Hedging Activities	122a	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200	
15	Nuclear Fuel Materials	202	N/A
16	Electric Plant in Service	204	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224	N/A
22	Materials and Supplies	227	
23	Allowances	228	
24	Extraordinary Property Losses	230a	N/A
25	Unrecovered Plant and Regulatory Study Costs	230b	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	N/A
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254b	
33	Long-Term Debt	256	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262	

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
0	Energy Storage Operations (Large Plants)	414	N/A
67	Transmission Line Statistics Pages	422	
68	Transmission Lines Added During Year	424	N/A
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 (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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.

Phillip S. Barnett
 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

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

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ 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, 2022, 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, 2022.			

FERC FORM No. 1 (ED. 12-96)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ 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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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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OFFICERS

- 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.
- 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	538,125		
2	Sr. Vice President and Chief Operating Officer	Olivier, Tamla A.	393,975		
3	Sr. Vice President, Chief Financial Officer and Treasurer	Barnett, Phillip S.	420,317		
4	Sr. Vice President, Governmental, Regulatory and External Affairs	Oddoye, Rodney	385,200		
5	Vice President and General Counsel	Bancroft, Anne	316,350		
6	Sr. Vice President, Customer Operations	Bell-Izzard, Morlon	338,250		
7	Corporate Secretary	Smith, Katherine	271,260		

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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DIRECTORS

- 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	Calvin G. Butler, Jr.	10 S. Dearborn Street, 54th Floor, Chicago, Illinois 60603	false	false

FERC FORM No. 1 (ED. 12-95)

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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

FERC FORM No. 1 (NEW. 12-08)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	Yes
	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	202220513-5203	05/13/2022	ER09-1158	Informational Filing of Annual Formula	

FERC FORM NO. 1 (NEW. 12-08)

Page 106a

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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		

FERC FORM No. 1 (NEW. 12-08)

Page 106b

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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.

- 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.
- 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.
- 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.
- 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.
- 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.
- 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.
- Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
- State the estimated annual effect and nature of any important wage scale changes during the year.
- 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.
- 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.
- (Reserved.)
- 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.
- Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
- 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.

- None
- None
- None
- None
- None
- 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 ES22-13-000. DPL has a currently effective shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2025. DPL's ability to sell securities off the shelf registration statement 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, DPL's current financial condition, its securities ratings and market conditions.
- None
- None
- Refer to Note 12, "Commitments and Contingencies" of the accompanying "Notes to Financial Statements" for a discussion of DPL's legal proceedings.
- None
- On February 21, 2021, Exelon's (parent of DPL) Board of Directors approved a plan to separate the Utility Registrants and Generation (Constellation Energy Generation, LLC formerly Exelon Generation Company, LLC). Exelon completed the separation on February 1, 2022, creating two publicly traded companies. Refer to Note 15, "Related Party Transactions" of the accompanying "Notes to Financial Statements" for discussion on the continued relationship between DPL and Generation.
- See Officers page (Page 104) and Directors page (Page 105) for details concerning changes in the respondent's officers during 2022.
- DPL participates in a cash management program. As of December 31, 2022, DPL's proprietary capital ratio is greater than 30 percent.

FERC FORM No. 1 (ED. 12-96)

Page 108-109

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	6,370,400,367	6,005,202,318
3	Construction Work in Progress (107)	200	264,332,443	229,738,612

4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,634,732,810	6,234,940,930
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	1,802,012,656	1,669,300,797
6	Net Utility Plant (Enter Total of line 4 less 5)		4,832,720,154	4,565,640,133
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)		4,832,720,154	4,565,640,133
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		14,070,447	13,968,767
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,598,736	4,543,901
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224		
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		198,186	262,199
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)		9,669,897	9,687,065
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		30,983,618	28,037,344
36	Special Deposits (132-134)		120,757,660	43,002,715
37	Working Fund (135)			
38	Temporary Cash Investments (136)		112,661	3,036
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		129,643,784	96,438,981
41	Other Accounts Receivable (143)		52,895,932	57,896,330
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		27,834,321	25,931,520
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		266,917	995,582
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	57,821,838	53,736,465
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	8,360,767	7,806,217
53	(Less) Noncurrent Portion of Allowances		228		
54	Stores Expense Undistributed (163)		227		
55	Gas Stored Underground - Current (164.1)			17,130,555	10,097,691
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			1,231,075	1,161,352
57	Prepayments (165)			23,697,652	21,440,278
58	Advances for Gas (166-167)				
59	Interest and Dividends Receivable (171)			1,742	203
60	Rents Receivable (172)			984,583	1,075,348
61	Accrued Utility Revenues (173)			74,475,104	53,427,993
62	Miscellaneous Current and Accrued Assets (174)			1,521,538	4,076,868
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)			492,051,105	353,264,883
68	DEFERRED DEBITS				
69	Unamortized Debt Expenses (181)			12,380,165	12,135,563
70	Extraordinary Property Losses (182.1)		230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)		230b		
72	Other Regulatory Assets (182.3)		232	180,806,450	175,486,178
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	154,740,210	160,079,219
79	Def. Losses from Disposition of Utility Plt. (187)				
80	Research, Devel. and Demonstration Expend. (188)		352		
81	Unamortized Loss on Required Debt (189)			3,791,624	4,474,688
82	Accumulated Deferred Income Taxes (190)		234	139,573,705	151,180,380
83	Unrecovered Purchased Gas Costs (191)				
84	Total Deferred Debits (lines 69 through 83)			491,292,154	503,356,028
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)			5,825,733,310	5,431,948,109

FERC FORM No. 1 (REV. 12-03)

Page 110-111

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	828,253,405	680,482,049
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	589,200,458	563,758,300
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	(2,177,779)	(2,177,779)
13	(Less) Reaquired 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)		1,942,966,280	1,769,752,766
17	LONG-TERM DEBT			
18	Bonds (221)	256	1,907,230,000	1,782,230,000
19	(Less) Reaquired 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)		1,126,004	1,645,914
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,230,116	1,279,634
24	Total Long-Term Debt (lines 18 through 23)		1,917,125,888	1,792,596,280
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		26,700,373	25,094,948
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		9,242,849	6,633,949
29	Accumulated Provision for Pensions and Benefits (228.3)		10,457,165	13,117,253
30	Accumulated Miscellaneous Operating Provisions (228.4)			
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)		12,963,876	15,804,218
35	Total Other Noncurrent Liabilities (lines 26 through 34)		59,364,263	60,650,368
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		114,909,268	148,556,358
38	Accounts Payable (232)		150,758,341	112,780,888
39	Notes Payable to Associated Companies (233)			
40	Accounts Payable to Associated Companies (234)		22,392,233	33,489,536
41	Customer Deposits (235)		28,903,784	28,019,029
42	Taxes Accrued (236)	262	7,692,042	9,930,973
43	Interest Accrued (237)		9,301,308	7,567,025
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		688,137	466,707
48	Miscellaneous Current and Accrued Liabilities (242)		171,075,991	91,289,738
49	Obligations Under Capital Leases-Current (243)		5,148,349	4,148,469

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)			510,869,453	436,248,723
55	DEFERRED CREDITS				
56	Customer Advances for Construction (252)			15,540,959	12,140,563
57	Accumulated Deferred Investment Tax Credits (255)	266		1,084,374	1,378,942
58	Deferred Gains from Disposition of Utility Plant (256)				
59	Other Deferred Credits (253)	269		26,415,927	29,508,136
60	Other Regulatory Liabilities (254)	278		343,951,133	375,972,745
61	Unamortized Gain on Required Debt (257)				
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272			
63	Accum. Deferred Income Taxes-Other Property (282)			907,921,311	854,372,948
64	Accum. Deferred Income Taxes-Other (283)			100,493,722	99,326,638
65	Total Deferred Credits (lines 56 through 64)			1,395,407,426	1,372,699,972
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)			5,825,733,310	5,431,948,109

FERC FORM No. 1 (REV. 12-03)

Page 112-113

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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STATEMENT OF INCOME

Quarterly

- 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.
- 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.
- 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.
- 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.
- 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 Utility 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	1,607,182,835	1,384,428,500			1,370,540,314	1,216,232,201	236,642,521	168,196,299		
3	Operating Expenses											
4	Operation Expenses (401)	320	987,468,927	803,742,983			811,478,906	684,983,520	175,990,021	118,759,463		
5	Maintenance Expenses (402)	320	78,586,294	81,018,366			72,038,197	74,258,580	6,548,097	6,759,786		
6	Depreciation Expense (403)	336	171,189,769	152,839,364			157,894,178	140,244,681	13,295,591	12,594,683		

47	Penalties (426.3)		205,954	212,220										
48	Exp. for Certain Civic, Political & Related Activities (426.4)		410,898	620,585										
49	Other Deductions (426.5)		3,798,571	6,260,982										
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,107,515	8,280,669										
51	Taxes Applic. to Other Income and Deductions													
52	Taxes Other Than Income Taxes (408.2)	262	667,971	712,284										
53	Income Taxes-Federal (409.2)	262	(818,619)	(1,061,576)										
54	Income Taxes-Other (409.2)	262												
55	Provision for Deferred Inc. Taxes (410.2)	234,272	398,632	4,160										
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234,272		551,394										
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)		247,984	(896,526)										
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		5,145,147	1,036,097										
61	Interest Charges													
62	Interest on Long-Term Debt (427)		67,211,431	61,958,099										
63	Amort. of Debt Disc. and Expense (428)		1,310,986	1,182,352										
64	Amortization of Loss on Required Debt (428.1)		683,065	857,297										
65	(Less) Amort. of Premium on Debt-Credit (429)		519,911	501,865										
66	(Less) Amortization of Gain on Required Debt-Credit (429.1)													
67	Interest on Debt to Assoc. Companies (430)		18,199	3,031										
68	Other Interest Expense (431)		(31,135)	(11,334)										
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,823,221	2,276,017										
70	Net Interest Charges (Total of lines 62 thru 69)		65,849,414	61,211,563										
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		168,172,158	126,379,097										
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)		168,172,158	126,379,097										

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
STATEMENT OF RETAINED EARNINGS			
<p>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).</p>			

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		563,758,300	584,379,203
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)		168,172,158	126,379,097
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			(142,730,000)	(147,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(142,730,000)	(147,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		589,200,458	563,758,300
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)		589,200,458	563,758,300
	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)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	Description (See Instructions No.1 for explanation of codes)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
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No.	(a)	(b)	(c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	168,172,158	126,379,097
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	171,189,769	152,839,364
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of regulatory debits/credits and limited plant	55,036,370	48,188,532
5.2	Amortized Plant Acquisition Adjustment	926,727	1,854,158
5.3	Unamortized Discount (Premium) on Long-Term Debt	1,498,314	1,531,756
8	Deferred Income Taxes (Net)	16,817,435	38,846,701
9	Investment Tax Credit Adjustment (Net)	(294,568)	(312,841)
10	Net (Increase) Decrease in Receivables	(46,530,824)	33,867,065
11	Net (Increase) Decrease in Inventory	(11,187,960)	(7,840,251)
12	Net (Increase) Decrease in Allowances Inventory	(554,550)	1,945,750
13	Net Increase (Decrease) in Payables and Accrued Expenses	5,204,471	8,804,524
14	Net (Increase) Decrease in Other Regulatory Assets	(37,989,080)	(29,682,901)
15	Net Increase (Decrease) in Other Regulatory Liabilities	17,483,075	(19,381,676)
16	(Less) Allowance for Other Funds Used During Construction	7,224,373	5,917,632
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Pension	4,894,810	4,108,754
18.2	^{ia} Other Operating Activities	(299,259)	(7,110,101)
18.3	Net Increase (Decrease) in Interest and Taxes Accrued	1,191,376	(6,680,050)
18.4	(Gain) Loss on Sales of Assets		
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	338,333,891	341,440,249
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	(436,892,260)	(435,218,926)
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	(7,224,373)	(5,917,632)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(429,667,887)	(429,301,294)
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	Other Investing Activities	(474,127)	1,930,186
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(430,142,014)	(427,371,108)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	125,000,000	125,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)		2,461,407
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Capital Contribution from Parent	147,771,356	119,300,000
70	Cash Provided by Outside Sources (Total 61 thru 69)	272,771,356	246,761,407
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		
76.2	Cost of Issuances	(1,530,244)	(1,122,871)
78	Net Decrease in Short-Term Debt (c)	(33,647,090)	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(142,730,000)	(147,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	94,864,022	98,638,536
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)	3,055,899	12,707,677
88	Cash and Cash Equivalents at Beginning of Period	28,040,380	15,332,703
90	Cash and Cash Equivalents at End of Period	31,096,279	28,040,380

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
FOOTNOTE DATA			

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivitiesDescription			
Other Operating Activities:		2022	2021
Net increases in Prepayments	\$	(2,257,374)	\$ (9,569,552)
Net decreases in Miscellaneous long term assets and deferred debits		449,609	1,930,199
Net decreases increase in Other deferred credits		(3,092,209)	(3,326,833)

Principal Portion of Capital Lease Payments	(5,328,834)	(3,906,017)
Net increases in Special Deposits	(77,754,945)	(43,002,227)
Net increases in Collateral received, net	77,755,307	43,002,480
Other	9,929,187	7,761,849
Total Other Operating Activities	\$ (299,259)	\$ (7,110,101)

(b) Concept: Other Adjustments To Cash Flows From Investment Activities Description

Other Investing Activities:	2022	2021
Re-capitalized Facilities Depreciation	\$ 1,874,827	\$ 1,612,508
Proceeds from Land Easement	—	80,505
Gain from Land Easement	—	(58,631)
Other	(2,348,954)	295,804
Total Other Investing Activities	\$ (474,127)	\$ 1,930,186

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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NOTES TO FINANCIAL STATEMENTS

- 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.
- 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.
- 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.
- Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, including the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
- Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
- 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.
- 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.
- 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 from 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.
- 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, 2022. 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.

Basis of Presentation

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

The accompanying financial statements as of December 31, 2022 and 2021 are audited, and in the opinion of the management of DPL, include all adjustments that are considered necessary for a fair presentation of DPL's financial statements in accordance with the Uniform System of Accounts (USOA). All adjustments are of a normal and recurring nature. The December 31, 2021 Balance Sheets were derived from audited financial statements. These notes should be read in conjunction with the Notes to Financial Statements of DPL in the December 31, 2021 FERC Form No. 1 "Annual Report of Major Electric Utilities, Licensees and Others" (FERC Form No. 1).

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 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.

COVID-19

DPL has taken steps to mitigate the potential risks posed by the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19). DPL provides a critical service to its customers and has taken measures to keep employees who operate the business safe and minimize unnecessary risk of exposure to the virus, including extra precautions for employees who work in the field. DPL has implemented work from home policies where appropriate and imposed travel limitations on employees.

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and accompanying notes, and the amounts of revenues and expenses reported during the periods covered by those financial statements and accompanying notes. As of December 31, 2022 and 2021, and through the date of this report, management assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, accumulated provision for uncollectible accounts and the carrying value of goodwill and other long-lived assets, in context with the information reasonably available and the unknown future impacts of COVID-19. DPL's future assessment of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts to their consolidated financial statements in future reporting periods.

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, environmental costs and other loss contingencies, asset retirement obligations (AROs), and 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 MDPS 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 and natural gas distribution revenue impacts resulting from future changes in rates that it believes are probable of approval by the MDPS 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 basis; 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, 2022 and 2021, DPL's restricted cash and cash equivalents primarily represented funds restricted for the collateral held from energy suppliers.

Accumulated Provision for Uncollectible Accounts on Accounts 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 developed by applying loss rates for DPL, based on historical loss experience, current conditions, and forward-looking risks factors to the outstanding receivable balance by customer risk segment. 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.

For DPL, 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 regarding Property, plant and equipment.

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 time 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 by issuing the guarantee. 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 experience different from that 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.

2. Regulatory Matters

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

Utility Regulatory Matters

Distribution Base Rate Case Proceedings

The following tables show the completed and pending distribution base rate case proceedings in 2022.

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	September 1, 2021 (amended December 23, 2021) ^(a)	Electric	\$ 27	\$ 13	9.60%	March 2, 2022	March 2, 2022
Maryland	May 19, 2022 ^(b)	Electric	38	29	9.60%	December 14, 2022	January 1, 2023
Delaware	January 14, 2022 (amended August 15, 2022)	Natural Gas	13	8	9.60%	October 12, 2022	August 14, 2022

(a) The approved settlement reflects a 9.60% ROE, which is solely for the purposes of calculating AFUDC and regulatory asset carrying costs.

(b) Reflects a three-year cumulative multi-year plan for January 1, 2023 through December 31, 2025. The MDPS awarded DPL electric incremental revenue requirement increases of \$17 million, \$6 million, and \$6 million for 2023, 2024, and 2025, respectively.

Pending Distribution Base Rate Case Proceedings

Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
Delaware	December 15, 2022	Electric	\$ 60	10.50%	Second quarter of 2024

(a) The rates will go into effect on July 15, 2023, 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 2022, the following total increases were included in DPL's electric transmission formula rate update:

Filing Date ^(a)	Initial Revenue Requirement Increase	Annual Reconciliation Increase	Total Revenue Requirement Increase	Allowed Return on Rate Base ^(b)	Allowed ROE ^(c)
May 13, 2022	\$ 9	\$ 2	\$ 11	7.09 %	10.50 %

- (a) Rate is effective June 1, 2022 - May 31, 2023, 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 MDPS approved BSAs for DPL, which are decoupling mechanisms. As a result of the decoupling mechanisms, certain Operating revenues from electric distribution are not 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.

Maryland Order Directing the Distribution of Energy Assistance Funds. On June 15, 2021, the MDPS issued an order authorizing the disbursement of funds to utilities in accordance with Maryland COVID-19 relief legislation. Under this order, DPL received funds of \$8 million in July 2021. The funds have been used to reduce or eliminate certain qualifying past-due residential customer receivables.

Other Federal Regulatory Matters

Transmission-Related Income Tax Regulatory Assets. On December 13, 2016 (and as amended on March 13, 2017), Baltimore Gas and Electric Company (BGE) filed with FERC to begin recovering certain existing and future transmission-related income tax regulatory assets through its transmission formula rate. BGE's existing regulatory assets included (1) amounts that, if BGE's transmission formula rate provided for recovery, would have been previously amortized and (2) amounts that would be amortized and recovered prospectively. On November 16, 2017, FERC issued an order rejecting BGE's proposed revisions to its transmission formula rate to recover these transmission-related income tax regulatory assets. In the fourth quarter of 2017, DPL fully impaired its associated transmission-related income tax regulatory asset for the portion of the income tax regulatory assets that would have been previously amortized.

On February 23, 2018 (as amended on July 9, 2018), DPL filed with FERC to revise their transmission formula rate mechanisms to permit recovery of transmission-related income tax regulatory assets, including those amounts that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery.

On September 7, 2018, FERC issued orders rejecting (1) BGE's rehearing request of FERC's November 16, 2017 order and (2) the February 23, 2018 (as amended on July 9, 2018) filing by DPL for similar recovery.

On November 2, 2018, BGE filed an appeal of FERC's September 7, 2018 order to the U.S. Court of Appeals for the D.C. Circuit. On March 27, 2020, the U.S. Court of Appeals for the D.C. Circuit Court denied BGE's November 2, 2018 appeal.

On October 1, 2018, DPL submitted a new filing to recover ongoing non-Tax Cuts and Jobs Act (TCJA) amortization amounts and credit TCJA transmission-related income tax regulatory liabilities to customers for the prospective period starting on October 1, 2018. On April 26, 2019, FERC issued an order accepting DPL's October 1, 2018 filing, effective October 1, 2018, subject to refund and established hearing and settlement judge procedures. On April 24, 2020, DPL and other parties filed a settlement agreement with FERC, which FERC approved on September 24, 2020. The settlement agreement provides for the recovery of ongoing transmission-related income tax regulatory assets and establishes the amount and amortization period for excess deferred income taxes resulting from TCJA. The settlement resulted in a reduction to Operating revenues and an offsetting reduction to Income tax expense in the second quarter of 2020.

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 as of December 31, 2022 and 2021:

	December 31, 2022		December 31, 2021
Regulatory Assets (Account 182.3)			
Advanced Metering Infrastructure (AMI) programs - deployment costs	\$ 22	\$	26
AMI programs - legacy meters	17		21
Asset retirement obligations	3		2
Electric energy and natural gas costs	27		14
Transmission formula rate annual reconciliations	5		8
Energy efficiency and demand response programs	77		81
Deferred storm costs	2		3
COVID-19	6		6
Other	22		14
Total regulatory assets	<u>\$ 181</u>	\$	<u>175</u>
Regulatory Liabilities (Account 254)			
	December 31, 2022		December 31, 2021
Deferred income taxes	\$ 305	\$	354
Electric energy and natural gas costs	8		4
Transmission formula rate annual reconciliations	1		—
Over-recovered revenue decoupling	6		3
COVID-19	3		3
Other	21		12
Total regulatory liabilities	<u>\$ 344</u>	\$	<u>376</u>

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
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. These amounts include transmission-related regulatory liabilities that require FERC approval generally refunded over the remaining depreciable life of the separate from the transmission formula rate. See Transmission-Related Income Tax Regulatory Assets section above for additional information.	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, 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
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
Asset retirement obligations	Represents future legally required removal costs associated with existing AROs.	Over the life of the related assets	Maryland - No Yes, once the removal activities have been performed
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
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.	2024	Yes
Energy efficiency and demand response programs	Includes under (over)-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.	2037	Maryland - Yes Delaware - No
Under (over) -recovered revenue decoupling	Represents electric and / or gas distribution costs recoverable from or refundable to customers under decoupling mechanisms.	2023	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
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 to be determined in pending distribution rate case filed with DEPSC	No

Capitalized Ratemaking Amounts Not Recognized

As of both December 31, 2022 and 2021, DPL had \$2 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. The earnings on energy efficiency are on DPL Delaware programs only. 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 for regulated electric and gas tariff sales and regulated transmission services unless noted below.

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 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. 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 30% undivided interest in those new agreements. DPL received cash and recorded contract liabilities as of July 1, 2020. The revenue attributable to this arrangement will be recognized as operating revenue over the 35 years under the collaborative arrangement.

The following table provides a rollforward of the contract liabilities reflected in DPL's Balance Sheet as of December 31, 2022 and 2021.

Balance as of December 31, 2020	\$	12
Revenues recognized ^(a)		(1)
Balance as of December 31, 2021		11
Revenues recognized ^(a)		(1)
Balance as of December 31, 2022	\$	<u>10</u>

(a) Revenue recognized in the years ended December 31, 2022 and 2021, were included in the contract liabilities at December 31, 2021 and 2020, 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 December 31, 2022 through the remainder of the 35-year term.

2023	2024	2025	2026	2027 and thereafter	Total
\$	\$	\$	\$	\$	\$
1	—	—	—	9	10

4. Account Receivable

Accumulated Provision for Uncollectible Accounts

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

	For the Year Ended December 31, 2022
Balance as of December 31, 2021	\$ 18
Plus: Current period provision for uncollectible accounts ^(a)	12
Less: Write-offs, net ^(b) of recoveries ^(c)	9
Balance as of December 31, 2022	<u>\$ 21</u>
	For the Year Ended December 31, 2021
Balance as of December 31, 2020	\$ 22
Plus: Current period provision for uncollectible accounts	6
Less: Write-offs, net of recoveries	10
Balance as of December 31, 2021	<u>\$ 18</u>

- (a) The change in current period provision for uncollectible accounts is primarily a result of increased receivable balances.
(b) The change in write-offs is primarily a result of favorable customer payment behavior.
(c) Recoveries were not material to DPL.

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

	For the Year Ended December 31, 2022
Balance as of December 31, 2021	\$ 8
Plus: Current period benefit for uncollectible accounts	(1)
Less: Write-offs, net of recoveries ^(a)	—
Balance as of December 31, 2022	<u>\$ 7</u>
	For the Year Ended December 31, 2021
Balance as of December 31, 2020	\$ 9
Plus: Current period benefit for uncollectible accounts	(1)
Less: Write-offs, net of recoveries	—
Balance as of December 31, 2021	<u>\$ 8</u>

(a) Recoveries were not material to DPL.

Accrued Utility Revenues

DPL accrued \$74 million and \$53 million of unbilled revenues as of December 31, 2022 and December 31, 2021, respectively, in Accrued Utility Revenues (Account 173).

Purchase of Customer and Other Accounts Receivable

DPL is required under legislation and regulations in Maryland and Delaware, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participate in its consolidated billing. The following table presents the total receivables DPL purchased:

	For the Years Ended December 31,	
	2022	2021
Total receivables purchased	\$ 205	\$ 217

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:

	December 31,	
	2022	2021 ^(a)
Electric - transmission and distribution	3.10 %	2.87 %
Gas - transportation and distribution	1.45 %	1.47 %
Common - electric and gas	10.03 %	8.69 %

(a) The depreciation rates as of December 31, 2021 have been updated from the rates previously disclosed in the 2021 FERC Form No. 1 to include the effect of total capitalized cloud computing costs and the associated amortization expense for the prior period.

The credits to AFUDC debt and equity were \$10 million and \$8 million for the years ended December 31, 2022 and 2021, respectively.

DPL has material undivided interests in jointly owned electric transmission facilities, which are financed with its funds and all operations are accounted for as if such participating interests were wholly owned facilities. DPL's share of direct expenses of the jointly owned plants are included in Operating and maintenance expenses on DPL's Statement of Income. DPL's undivided ownership interests in jointly owned electric transmission facilities at December 31, 2022 and 2021 were as follows:

Operator	PSEG/DPL
DPL's share at December 31, 2022	N/A ^(a)
Plant in service	\$ 3

Accumulated depreciation 2

DPL's share at December 31, 2021	NJ/DE^(a)
Plant in service	\$ 3
Accumulated depreciation	2

(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.

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 the accounting policy for AROs.

The following table provides a rollforward of the AROs reflected on DPL's Comparative Balance Sheet from January 1, 2021 to December 31, 2022:

ARO at January 1, 2021	\$	14
Net increase due to changes in, and timing of, estimated future cash flows		2
ARO at December 31, 2021 (Account 230)		16
Net decrease due to changes in, and timing of, estimated future cash flows		(3)
ARO at December 31, 2022 (Account 230)	\$	13

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,	
	2022	2021
Included in operations:		
Federal		
Current	\$ (2)	\$ 2
Deferred	2	(14)
State		
Current	—	1
Deferred	14	53
Total	\$ 14	\$ 42

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,	
	2022 ^{(a)(b)}	2021 ^{(a)(b)}
U.S. Federal statutory rate	21.0 %	21.0 %
Increase (decrease) due to:		
State income taxes, net of Federal income tax benefit	6.5	25.0
Plant Basis differences	(0.7)	(0.8)
Excess deferred tax amortization	(18.4)	(20.0)
Amortization of investment tax credit, including deferred taxes on basis differences	(0.2)	(0.2)
Tax credits	(0.6)	(0.4)
Other	0.1	0.1
Effective income tax rate	7.7 %	24.7 %

- (a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
- (b) The lower effective tax rate is primarily related to the acceleration of certain income tax benefits due to distribution and transmission rate case settlements.
- (c) The higher effective tax rate is primarily related to a state income tax expense, net of federal income tax benefit, due to the recognition of a valuation allowance of approximately \$31 million against a deferred tax asset associated with Delaware net operating loss carryforwards as a result of a change in Delaware tax law.

Tax Differences and Carryforwards

The tax effects of temporary differences, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2022 and 2021 are presented below:

	As of December 31,	
	2022	2021
Plant basis differences	\$ (906)	\$ (853)
Deferred pension and postretirement obligation	(39)	(40)
Deferred debt refinancing costs	(2)	(1)
Regulatory assets and liabilities	43	55
Tax loss carryforward, net of valuation allowances	20	18
Other, net	15	18
Deferred income tax liabilities, net (Accounts 190, 282, 283)	(869)	(803)
Unamortized investment tax credits (Account 255)	(1)	(1)
Total deferred income tax liabilities (net) and unamortized investment tax credits	\$ (870)	\$ (804)

The following table provides DPL's state carryforwards, which are presented on a post-apportioned basis and corresponding valuation allowances as of December 31, 2022. Note, there were no Federal carryforwards.

State net operating losses and other carryforwards	\$	768
Deferred taxes on state tax attributes (net of federal taxes)		52
Valuation allowance on state tax attributes (net of federal taxes) ^(a)		31
Year in which net operating loss or credit carryforwards will begin to expire ^(b)		2032

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

Tabular Reconciliation of Unrecognized Tax Benefits

DPL's unrecognized tax benefits are not material as of December 31, 2022 and 2021.

Recognition of unrecognized tax benefits

DPL's unrecognized tax benefits that, if recognized, would decrease the effective tax rate are not material as of December 31, 2022 and 2021.

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, 2022 and 2021.

DPL's interest and penalty expense related to tax positions are not material at both December 31, 2022 and 2021.

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

	Open Years	
	2010-2021	
Federal consolidated income tax returns ^(a)	Same as federal	
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

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, 2022 and 2021.

Allocation of Tax Benefits

DPL is party to an agreee

nt 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. DPL's federal tax benefit allocation from Exelon under the Tax Sharing Agreement was \$3 million as of December 31, 2022. During 2021, 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.

8. Retirement Benefits

Defined Benefit Pension and Other Postretirement Employee Benefits

Effective February 1, 2022, in connection with the separation, Exelon restructured certain of its qualified pension plans. However, the qualified pension plans DPL participates in were not affected by the restructuring.

The table below shows the pension and OPEB plans in which Peppo employees participated as of December 31, 2022:

Name of Plan^(a):

Qualified Pension Plans:

- Exelon Corporation Retirement Program^(b)
- Exelon Pension Plan^(c)
- Peppo Holdings LLC Retirement Plan^(d)

Non-Qualified Pension Plans:

- Exelon Corporation Supplemental Management Retirement Plan^(b)
- Peppo Holdings LLC 2011 Supplemental Executive Retirement Plan^(d)
- Connectiv Supplemental Executive Retirement Plan^(d)

OPEB Plans:

- PECO Energy Company Retiree Medical Plan^(b)
- Exelon Corporation Health Care Program^(b)
- BGE Retiree Medical Plan^(c)
- Peppo Holdings LLC Welfare Plan for Retirees^(d)

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

(b) These plans are collectively referred to as the legacy Exelon plans.

(c) These plans are collectively referred to as the legacy Constellation Energy Group (CEG) Plans.

(d) These plans are collectively referred to as the legacy PHI plans.

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 and maintenance expense within its Statements of Income and capital expenditures within its Balance Sheet for the years ended December 31, 2022 and 2021.

	2022	2021
Pension and OPEB	\$ 3	\$ 2

Contributions

The following table provide DPL's contributions to the pension plan for the years ended December 31, 2022 and 2021:

	2022	2021
Pension	\$ 1	\$ 1

DPL's contributions to its OPEB plans were immaterial for the period.

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).

DPL's planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to OPEB plans in 2023 are immaterial.

Defined Contribution Savings Plan

DPL participates in a 401(k) defined contribution savings plans that are sponsored by Exelon. The plans 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, 2022 and 2021.

	2022	2021
Savings Plan Matching Contributions	\$ 3	\$ 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 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 on-derivative or classified as economic hedges. DPL procures electric and natural gas supply through a competitive procurement process approved by MDPS 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, 2022 and 2021.

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, 2022, the amount of cash collateral held with external counterparties by DPL was \$121 million, which is recorded in Miscellaneous Current and Accrued Liabilities (Account 242) in DPL's Balance Sheet. The amount of cash collateral received from external counterparties increased as of December 31, 2022 due to rising energy prices. As of December 31, 2021, the amount of cash collateral held with external counterparties by DPL was \$43 million.

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, 2022, DPL was not required to post collateral for any of these agreements. If DPL lost its investment grade credit rating as of December 31, 2022, it could have been required to post collateral to its counterparties of \$15 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, 2022 and 2021:

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,	
2022 ^{(a)(b)}	2021 ^{(a)(b)}	2022	2021	2022	2021
\$ 300	\$ 300	\$ 115	\$ 149	4.76 %	0.36 %

(a) As of December 31, 2022, excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of \$15 million. These facilities expire on October 6, 2023. These facilities are solely utilized to issue letters of credit. As of December 31, 2021, excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of \$8 million.

(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 (Peppo), 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. As of December 23, 2022, this ability was utilized to increase Pepco's program size to \$400 million. As a result, the program sizes for DPL and ACE were decreased to \$250 million each, which prevents the aggregate amount of outstanding short-term debt from potentially exceeding the \$900 million limit.

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, 2022, DPL had the following aggregate bank commitments, credit facility borrowings and available capacity under its credit facilities:

Facility Type	Aggregate Bank Commitment ^(a)	Facility Draws	Outstanding Letters of Credit	Available Capacity as of December 31, 2022	
				Actual	To Support Additional Commercial Paper
Syndicated Revolver ^(b)	\$ 300	\$ —	\$ —	\$ 300	\$ 185

(a) On February 1, 2022, DPL's syndicated revolving credit facilities were replaced with a new 5-year revolving credit facility with an aggregate bank commitment of \$300 million at a variable interest rate of SOFR plus 1.000%.

(b) Excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of \$15 million. These facilities expire on October 6, 2023. These facilities are solely 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 its credit rating. The adders for the prime based and SOFR based borrowings are 0 basis points and 100 basis points, respectively. 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.

Variable Rate Demand Bonds

DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDBs). 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 both December 31, 2022 and 2021, \$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, 2022 and 2021:

	Rates	Maturity Date	December 31,	
			2022	2021
Long-term debt				
First mortgage bonds (Account 221) ^{(a)(b)(c)}	1.05% - 4.27%	2023 - 2052	\$ 1,874	\$ 1,749
Unsecured tax-exempt bonds (Account 221)	4.00% - 4.05%	2024	33	33
Medium-terms notes (unsecured) (Account 224)	7.72%	2027	10	10
Finance leases (Accounts 227 and 243)	5.39%	2025-2030	32	29
Total long-term debt			1,949	1,821
Unamortized debt discount and premium, net (Accounts 225 and 226) ^(d)			—	—
Long-term debt			\$ 1,949	\$ 1,821

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

(b) On March 15, 2023, DPL entered into a purchase agreement of First Mortgage Bonds of \$60 million and \$65 million at 5.30% and 5.57% due on March 15, 2033 and March 15, 2053, respectively. The closing date of the issuances occurred on March 15, 2023.

(c) On March 15, 2023, DPL entered into a purchase agreement of First Mortgage Bonds of \$340 million, \$75 million and \$110 million at 5.45%, 5.55% and 5.72% due on November 8, 2033, November 8, 2038 and November 8, 2053, respectively. The closing date of the issuance is expected to occur in November 2023.

(d) The amount in the Unamortized debt discount and premium, net category was less than \$1 million as of December 31, 2022 and 2021.

Long-term debt maturities at DPL in the periods 2023 through 2027 and thereafter are as follows:

Year	DPL
2023	\$ 584
2024	6
2025	84
2026	6
2027	15
Thereafter	1,254
Total	\$ 1,949

Debt Covenants

As of December 31, 2022, 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, 2022 and 2021. DPL has no financial liabilities classified as Level 1 or measured using the NAV practical expedient.

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.

	December 31, 2022				December 31, 2021			
	Carrying Amount	Fair Value			Carrying Amount	Fair Value		
		Level 2	Level 3	Total		Level 2	Level 3	Total
Long-term debt (Account 221, 224-227, 243)	\$ 1,949	\$ 1,164	\$ 458	\$ 1,622	\$ 1,822	\$ 1,426	\$ 552	\$ 1,978

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, 2022 and 2021. DPL has no financial assets or liabilities measured using the NAV practical expedient:

As of December 31, 2022

Assets	Level 1	Level 2	Level 3	Total
	Cash equivalents (Accounts 132-134, 136) ^(a)	\$ 121	\$ —	\$ —
Total assets	121	—	—	121
Total net assets	\$ 121	\$ —	\$ —	\$ 121

As of December 31, 2021

Assets	Level 1	Level 2	Level 3	Total
	Cash equivalents (Accounts 132-134, 136) ^(a)	\$ 43	\$ —	\$ —
Total assets	43	—	—	43
Total net assets	\$ 43	\$ —	\$ —	\$ 43

(a) DPL excluded cash of \$31 million and \$28 million as of December 31, 2022 and December 31, 2021, respectively.

DPL had no Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2022 and 2021.

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.

Rabbi Trust Investments. The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of DPL's executive management and directors. The Rabbi trusts' assets are included in investments in DPL's Balance Sheet and consists primarily of money market funds and life insurance policies. Money market funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Life insurance policies that are valued using

unobservable inputs have been categorized as Level 3, where the fair value is determined based on the cash surrender value of the policy, which contains unobservable inputs and assumptions. Because DPL relies on its third-party insurance provider to develop the inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to DPL. Therefore, DPL has not disclosed such inputs.

Deferred Compensation Obligations. DPL's deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. DPL includes such plans in other current and noncurrent liabilities in DPL's Balance Sheet. The value of DPL's deferred compensation obligations is based on the market value of the participants' notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

The value of certain employment agreement obligations are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

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 as of December 31, 2022:

Description	December 31, 2022	
Total commitments	\$	89
Remaining commitments ^(a)		4

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

DPL has committed to conducting three RFP's to procure up to a total of 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards. DPL has completed the three required wind REC RFPs. The first 40 MW wind REC tranche was conducted in 2017 and did not result in a purchase agreement. The second 40 MW wind REC tranche was conducted in 2018 and resulted in a proposed REC purchase agreement that was approved by the DEPSC in 2019. The third and final 40 MW wind REC tranche was conducted in 2022 and did not result in a purchase agreement. On December 14, 2022, the DEPSC issued an order recognizing DPL's completion of all obligations under this merger commitment.

Commercial Commitments

DPL's commercial commitments as of December 31, 2022, representing commitments potentially triggered by future events, were as follows:

Total	Expiration within					2028 and beyond
	2023	2024	2025	2026	2027	
Surety bonds ^(a)	\$ 7	\$ 7	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	12	—	3	2	2	3
Total commercial commitments	\$ 19	\$ 7	\$ 3	\$ 2	\$ 2	\$ 3

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

(b) Represents the maximum potential obligation in the event that 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 \$28 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, 2022 were as follows:

2023	\$	10
2024		9
2025		7
2026		5
2027		6
Remaining years		25
Total minimum future lease payments	\$	62

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 that is 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, 2022 and 2021, DPL had accrued \$1 million in undiscounted amounts for environmental liabilities in Account 228.4, Accumulated Miscellaneous Operating Provisions 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 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.

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, 2022 and 2021:

	Par Value	Shares Authorized	December 31,	
			2022	2021
			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, 2022 and 2021.

14. Supplemental Financial Information

Supplemental Statement of Income Information

The following table provides additional information about DPL's Statement of Income for the years ended December 31, 2022 and 2021:

Taxes other than income (Accounts 408.1 and 408.2)	For the Years Ended December 31,	
	2022	2021
Utility ^(a)	\$ 25	\$ 22
Property	42	40
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, 2022 and 2021:

Cash paid (refunded) during the year	For the Years Ended December 31,	
	2022	2021
Interest (net of amount capitalized)	\$ 63	\$ 59
Income taxes (net of refunds)	(2)	(9)

9	Total (lines 7 and 8)								168,172,158	168,172,158
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: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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)	5,953,516,404	4,975,856,718	782,860,139				194,799,547
4	Property Under Capital Leases	43,987,453	43,987,453					
5	Plant Purchased or Sold							
6	Completed Construction not Classified	307,410,788	224,779,663	71,829,585				10,801,540
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	6,304,914,645	5,244,623,834	854,689,724				205,601,087
9	Leased to Others							
10	Held for Future Use	15,439,441	15,439,441					
11	Construction Work in Progress	264,332,443	236,265,988	22,657,629				5,408,826
12	Acquisition Adjustments	50,046,281	50,046,281					
13	Total Utility Plant (8 thru 12)	6,634,732,810	5,546,375,544	877,347,353				211,009,913
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,802,012,656	1,419,324,453	262,296,690				120,391,513
15	Net Utility Plant (13 less 14)	4,832,720,154	4,127,051,091	615,050,663				90,618,400
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	1,671,134,988	1,328,136,984	260,874,891				82,123,113
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	80,831,387	41,141,188	1,421,799				38,268,400
22	Total in Service (18 thru 21)	1,751,966,375	1,369,278,172	262,296,690				120,391,513
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)	1,802,012,656	1,419,324,453	262,296,690				120,391,513

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

- Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
- 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: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

- Report below the original cost of electric plant in service according to the prescribed accounts.
- 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.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- 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.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- 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.
- 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.
- 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.
- 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	Account	Balance Beginning of Year	Additions	Retirements	Adjustments	Transfers	Balance at End of Year
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No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchise and Consents	2,341					2,341
4	(303) Miscellaneous Intangible Plant	37,385,124	14,902,463				52,287,587
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	37,387,465	14,902,463				52,289,928
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	81,830,476	14,625,854	459,483		95,996,847
50	(353) Station Equipment	650,990,098	37,449,197	4,428,754		684,010,541
51	(354) Towers and Fixtures	73,958,461				73,958,461
52	(355) Poles and Fixtures	587,016,069	11,125,607	701,349		597,440,327
53	(356) Overhead Conductors and Devices	318,737,961	8,602,257	1,256,694		326,083,524
54	(357) Underground Conduit	6,076,346				6,076,346
55	(358) Underground Conductors and Devices	62,694,632	2,093			62,696,725
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)	1,836,499,158	71,805,008	6,846,280		1,901,457,886
59	4. Distribution Plant					
60	(360) Land and Land Rights	15,385,479				15,385,479
61	(361) Structures and Improvements	55,032,370	3,289,930	843,329		57,478,971
62	(362) Station Equipment	457,591,469	37,865,379	1,879,871		493,576,977
63	(363) Energy Storage Equipment - Distribution					
64	(364) Poles, Towers, and Fixtures	250,257,627	13,290,980	726,957		262,821,650
65	(365) Overhead Conductors and Devices	413,590,372	30,585,647	3,119,918	34,000,437	475,056,538
66	(366) Underground Conduit	26,043,049	(53,640)	5,715		25,983,694
67	(367) Underground Conductors and Devices	433,918,536	23,782,945	1,768,953		455,932,528
68	(368) Line Transformers	620,073,413	32,476,016	3,597,301		648,952,128
69	(369) Services	220,623,796	7,205,328	193,417		227,635,707
70	(370) Meters	133,071,351	5,034,460	1,512,309		136,593,502
71	(371) Installations on Customer Premises	42,313,007	1,433,596	2,874		43,743,729
72	(372) Leased Property on Customer Premises					
73	(373) Street Lighting and Signal Systems	77,334,332	8,357,969	2,072,373		83,619,928
74	(374) Asset Retirement Costs for Distribution Plant	6,694,105	(1,020,817)	79,545		5,593,743
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,751,928,906	162,247,793	15,802,562	34,000,437	2,932,374,574
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	3,028,526	(30,280)			2,998,246
87	(390) Structures and Improvements	43,075,011	13,173,472	1,049,296		55,199,187

88	(391) Office Furniture and Equipment	15,557,980	1,698,990	3,217,598		14,039,372
89	(392) Transportation Equipment	37,621,590	7,692,264			45,313,854
90	(393) Stores Equipment	318,062		5,020		313,042
91	(394) Tools, Shop and Garage Equipment	19,918,259	3,393,474	461,850		22,849,883
92	(395) Laboratory Equipment					
93	(396) Power Operated Equipment					
94	(397) Communication Equipment	207,840,237	39,699,547	1,816,190	(33,589,327)	212,134,267
95	(398) Miscellaneous Equipment	4,066,249	969,181	10,399		5,025,031
96	SUBTOTAL (Enter Total of lines 86 thru 95)	331,425,914	66,596,648	6,560,353	(33,589,327)	357,872,882
97	(399) Other Tangible Property	4,735				4,735
98	(399.1) Asset Retirement Costs for General Plant	563,846	59,983			623,829
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	331,994,495	66,656,631	6,560,353	(33,589,327)	358,501,446
100	TOTAL (Accounts 101 and 106)	4,957,810,024	315,611,895	29,209,195	411,110	5,244,623,834
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)	4,957,810,024	315,611,895	29,209,195	411,110	5,244,623,834

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	Grasonville Substation : SS336B	12/01/2019	12/31/2024	3,178,224
3	Queenstown Substation: SSTA979	12/01/2019	12/31/2024	1,592,742
4	Ocean City-West Culver : SS322B	11/01/2019	12/31/2026	516,156
5	Lakeside Substation Land; 8 Acres, Talbot County MD	12/01/2010	06/01/2030	406,468
6	Magnolia Substation Land: 11+Acres	08/01/2010	06/01/2030	1,180,361
7	Ocean City-St Louis & 2nd : SSTA749	12/01/2020	12/31/2026	760,286
8	Graceton Jenkins Sub	02/15/2021	12/31/2026	1,372,880
9	Culver Substation	12/01/2021	02/28/2024	587,224
10	Maridel Substation	12/31/2022	12/31/2026	5,435,572
11	Total of Land under \$250,000	12/01/2019	12/31/2025	409,528

21	Other Property:			
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47	TOTAL			15,439,441

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	6719 E Market To Cambridge Rebuild	23,804,395
2	64405: DPL: Kennett Square TSO Renovation	14,301,538
3	DPL MD CAP: Queenstown Substation	8,861,901
4	DPL MD CAP: Narrows Substation	8,107,030
5	DPL MD CAP:QUEENSTWN ITN 75170	7,985,595
6	Kennett Data Center (DPL) Cap	6,008,284
7	Indian River Spare Transformer	5,913,334
8	EU GIS CORE Software	5,104,669
9	DPL MD CAP: UTSDRD8QG1	4,714,332
10	EU ADMS Implementation Software	3,927,520

11	Substation FO Entrance DPL MD	3,775,525
12	6727 Church to Massey REA	3,545,297
13	Brandywine Switchgear Replacement	3,427,648
14	Crisfield Kings Creek Construction	3,268,327
15	Router Upgrade Cores Edges DE	3,208,617
16	Basin Road CH Install	2,947,368
17	Tower Replacement DE	2,929,885
18	Rebuild Overhead Rear Lot Distribution Systems	2,547,153
19	IDS Design Build Install DE	2,514,049
20	Crisfield Substation New 69KV Term	2,482,303
21	SA-6719 Underbuild-UDLDRM4S01	2,467,147
22	Culver 2nd Transformer	2,409,566
23	Rebuild 6755 Line	2,334,209
24	69kV Cap Bank at Cool Spring	2,321,158
25	OCMD Battery Storage Substation	2,137,081
26	MILLSBORO NEW BREAKER AND T2	1,977,981
27	Wilmington Street Light Conver	1,805,999
28	ADMS Software	1,582,950
29	Easton Snake Fence & Gate	1,544,955
30	Harmony T3 Transformer Replace	1,481,526
31	Cable DE	1,468,722
32	DPL KSQ Security Fence	1,462,940
33	6831 Carrcroft - Silverside	1,459,231
34	Piney Grove AT20 Replace	1,400,301
35	MD Tr - Civil Assessment III	1,385,211
36	Substation FO Entrance DE	1,371,903
37	Crisfield T1 Replace XFMR ECA	1,360,665
38	ADMS - Network Hardware	1,356,028
39	Router Upgrade Cores Edges DPL MD	1,323,491
40	Cambridge Ground Grid	1,319,881
41	West T4 Transformer Install	1,270,047
42	IDS Design Build Install DPL MD	1,269,668
43	Basin Rd T2 Transformer Replacement	1,268,972
44	Nelson Sub: SVC Control System	1,254,554
45	Mechanics T1 Failure	1,235,531
46	Chesapeake College Communication Lines	1,218,962
47	6709 Vienna - West Cambridge Rebuild	1,208,851
48	13704 Felton to Cheswold	1,206,228
49	Maridel T1 Replace Transformer ECA	1,176,898
50	Centerville EV Charging Station	1,169,771
51	Reliability Improvement DE	1,151,352
52	Milford Substation - FEP	1,125,102
53	6709 Vienna - West Cambridge	1,114,585
54	Pemberton T2 transformer Replace	1,114,341
55	Keeney EHV 504 Spare Breaker Replacement	1,081,130
56	Distribution Automation DE	1,029,361
57	MD Transmission Station Service Replacement	1,012,636

58	Miscellaneous projects under \$1,000,000	63,012,284
43	Total	236,265,988

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	1,238,105,515	1,238,105,515		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	152,264,456	152,264,456		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,851,811	2,851,811		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	569,825	569,825		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	155,686,092	155,686,092		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(29,209,195)	(29,209,195)		
13	Cost of Removal	(38,503,284)	(38,503,284)		
14	Salvage (Credit)	569,871	569,871		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(67,142,608)	(67,142,608)		
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	1,487,985	1,487,985		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,328,136,984	1,328,136,984		
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	484,485,970	484,485,970		
26	Distribution	759,198,514	759,198,514		
27	Regional Transmission and Market Operation				
28	General	84,452,500	84,452,500		
29	TOTAL (Enter Total of lines 20 thru 28)	1,328,136,984	1,328,136,984		

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42	Total Cost of Account 123.1 \$		Total					

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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MATERIALS AND SUPPLIES

- 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.
- 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)	49,124,396	51,747,389	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)	614,789	888,692	Electric
9	Distribution Plant (Estimated)	3,997,280	5,185,757	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)	53,736,465	57,821,838	
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	53,736,465	57,821,838	

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																			

FERC FORM No. 1 (ED. 12-95)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
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20	TOTAL					
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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
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49	TOTAL					

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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 No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	Transmission Studies				
2	N/A				
20	Total				
21	Generation Studies				
22	N/A				
39	Total				
40	Grand Total				

FERC FORM No. 1 (NEW. 03-07)

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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	^(a) DE Deferred Fuel Costs-Gas		15,696,882	^(d) 254	15,696,882	
2	Other Vacation Accrual	3,349,189	3,299,699	^(d) various	3,349,190	3,299,698
3	Asset Retirement Obligation	2,371,395	838,822	^(d) 108	706,738	2,503,479
4	^(b) Transmission Service Revenue	7,829,627	32,418,606	^(d) various	35,227,628	5,020,605
5	^(a) DE Renewable Energy Portfolio Standards	1,935,874	35,420,819	^(d) various	37,356,693	
6	^{(a)(a)} DE Electric Costs to Achieve (CTA) Deferral	1,013,571		407.3	833,776	179,795
7	⁽ⁱ⁾ DE FAS 133 Gas Derivatives	475,085	6,862,288	^(d) 242	475,085	6,862,288
8	^(a) DE Third Party Supplier Recovery	2,188,894	2,094,112	^(d) various	2,025,867	2,257,139
9	^(a) MD Third Party Supplier Recovery	1,202,540	1,301,344	^(d) various	1,860,866	643,018
10	⁽ⁱ⁾⁽ⁱ⁾ MD Costs to Achieve (CTA) Deferral	609,213		407.3	340,622	268,591
11	Billing System-MD Recovery	40,208		903	40,208	
12	^{(a)(i)} MD Rate Case Costs	67,838	716,025	928	79,764	704,099
13	^(a) DE DSM - Energy Efficiency	667,508	2,612,602	908	2,502,529	777,581
14	^{(a)(a)} AMI / Smart Grid - DE	25,052,709	103,764	^(d) various	4,010,596	21,145,877
15	^{(a)(a)} Recoverable DE DLC Costs	11,448,112		407.3	2,102,472	9,345,640
16	^{(a)(a)} DE Gas IMU	5,303,539	21,208	^(d) various	706,772	4,617,975
17	^{(a)(a)} DE Gas Costs to Achieve (CTA) Deferral	391,156		407.3	256,252	134,904

18	DSM - Energy Efficiency Products MD	61,590,866	24,918,085	407.3	25,162,290	61,346,661
19	^{(b)(1)} DSM - Direct Load Control Program MD	6,534,585	704,996	407.3	1,616,787	5,622,794
20	^{(b)(1)} AMI / Smart Grid - MD	8,642,974	72,792	407.3	1,773,172	6,942,594
21	^{(b)(1)} MD AMI Loss on Retirement of Meters	7,614,813		407.3	1,435,293	6,179,520
22	^{(b)(1)} Delaware SOS: Energy	2,769,516	17,409,688	407.3	10,182,261	9,996,943
23	^{(b)(1)} Delaware SOS: Transmission	5,070,739	9,689,379	407.3	3,933,503	10,826,615
24	^{(b)(1)} Delaware SOS: Administrative Costs	2,714,338	563,052	407.3	2,542,990	734,400
25	^{(b)(1)} Delaware SOS: Interest		598,933	^{(b)(1)} 254	425,720	173,213
26	^{(b)(1)} Maryland SOS: Energy	723,061	17,179,711	^{(b)(1)} various	13,442,120	4,460,652
27	^{(b)(1)} Maryland SOS: Transmission	2,625,203	3,873,879	^{(b)(1)} various	6,117,946	381,136
28	^{(b)(1)} Maryland SOS: Administrative Costs	182,095	3,747,908	^{(b)(1)} various	3,715,550	214,453
29	^{(b)(1)} MD Incremental Storm Costs	3,176,314		^{(b)(1)} various	1,081,288	2,095,026
30	^{(b)(1)} Tax Cuts and Jobs Act	865,698	4,620,584	^{(b)(1)} various	1,112,050	4,374,232
31	^{(b)(1)} MD RM54 Recovery	136,441		903	88,580	47,861
32	^{(b)(1)} MD Electric Vehicle	552,375	417,712	^{(b)(1)} various	63,679	906,408
33	^{(b)(1)} DE Incremental COVID-19 Cost	5,441,568				5,441,568
34	^{(b)(1)} MD Incremental COVID-19 Cost	568,098	658,385	^{(b)(1)} various	372,283	854,200
35	^{(b)(1)} DE Electric Vehicle	14,600	6,600	588	21,200	
36	^{(b)(1)} MD Battery Storage	1,700,478	725,485			2,425,963
37	^{(b)(1)} MD Dynamic Pricing - Critical Peak Rebate Credits	615,958	29,402	407.3	645,360	
38	^{(b)(1)} MD Incremental IJJA Costs		21,522			21,522
44	TOTAL	175,486,178	186,624,284		181,304,012	180,806,450

FERC FORM No. 1 (REV. 02-04)

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FOOTNOTE DATA

^(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets	
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:	
Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
DE Deferred Fuel Costs-Gas	DEPSC Docket No. 19-0556
^(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets	
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:	
Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
Transmission Service Revenue	FERC Docket No. ER05-515
^(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets	
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:	
Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
DE Renewable Energy Portfolio Standards	DEPSC Regulation Docket No. 56
^(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets	
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:	
Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism

DE Electric Costs to Achieve (CTA) Deferral		DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977, DEPSC Docket No. 20-0149
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL amortizes its regulatory assets in account 182.3 based on the following amortization periods:		
Description of Other Regulatory Assets		Amortization Lives
DE Electric Costs to Achieve (CTA) Deferral	5 years	
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets		Rate Order Docket Number or Recovery Mechanism
DE FAS 133 Gas Derivatives	DEPSC Docket No. 97-293F	
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets		Rate Order Docket Number or Recovery Mechanism
DE Third Party Supplier Recovery	DEPSC Docket No. 15-1693	
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets		Rate Order Docket Number or Recovery Mechanism
MD Third Party Supplier Recovery	MDPSC Maillog 116829	
(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets		Rate Order Docket Number or Recovery Mechanism
MD Costs to Achieve (CTA) Deferral	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630	
(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL amortizes its regulatory assets in account 182.3 based on the following amortization periods:		
Description of Other Regulatory Assets		Amortization Lives
MD Costs to Achieve (CTA) Deferral	5 years	
(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets		Rate Order Docket Number or Recovery Mechanism
MD Rate Case Costs	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630, MDPSC Case No. 9670	
(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL amortizes its regulatory assets in account 182.3 based on the following amortization periods:		
Description of Other Regulatory Assets		Amortization Lives
MD Rate Case Costs	3 years	
(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets		Rate Order Docket Number or Recovery Mechanism
DE DSM - Energy Efficiency	DEPSC Docket No. 17-0985	
(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets		Rate Order Docket Number or Recovery Mechanism
AMI / Smart Grid - DE	DEPSC Docket No. 11-528, DEPSC Docket No. 13-115, DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977	
(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL amortizes its regulatory assets in account 182.3 based on the following amortization periods:		
Description of Other Regulatory Assets		Amortization Lives
AMI / Smart Grid - DE	15 years	
(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets		Rate Order Docket Number or Recovery Mechanism
Recoverable DE DLC Costs	DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977	
(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL amortizes its regulatory assets in account 182.3 based on the following amortization periods:		
Description of Other Regulatory Assets		Amortization Lives
Recoverable DE DLC Costs	10 years	
(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL amortizes its regulatory assets in account 182.3 based on the following amortization periods:		
Description of Other Regulatory Assets		Amortization Lives
DE Gas IMU	15 years	
(s) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
DE Gas IMU	DEPSC Docket No. 09-2777, DEPSC Docket No. 10-237, DEPSC Docket No. 11-528, DEPSC Docket No. 12-546, DEPSC Docket No. 17-0978

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Amortization Lives
DE Gas Costs to Achieve (CTA) Deferral	5 years

(ii) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
DE Gas Costs to Achieve (CTA) Deferral	DEPSC Docket No. 17-0978, DEPSC Docket No. 20-0150

(v) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
DSM - Energy Efficiency Products MD	MDPSC Case No. 9156

(w) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Amortization Lives
DSM - Energy Efficiency Products MD	5 years

(x) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Amortization Lives
DSM - Direct Load Control Program MD	15 years

(y) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
DSM - Direct Load Control Program MD	MDPSC Case No. 9156

(z) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Amortization Lives
AMI / Smart Grid - MD	10 years

(aa) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
AMI / Smart Grid - MD	MDPSC Case No. 9424, MDPSC Case No. 9455

(ab) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
MD AMI Loss on Retirement of Meters	MDPSC Case No. 9424

(ac) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Amortization Lives
MD AMI Loss on Retirement of Meters	10 years

(ad) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
Delaware SOS: Energy	DEPSC Docket No. 04-391

(ae) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
Delaware SOS: Transmission	DEPSC Docket No. 04-391

(af) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
Delaware SOS: Administrative Costs	DEPSC Docket No. 04-391

(ag) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
Delaware SOS: Interest	DEPSC Docket No. 04-391

(ah) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
Maryland SOS: Energy	MDPSC Case No. 8908

(ai) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
Maryland SOS: Transmission	MDPSC Case No. 8908

(aj) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
Maryland SOS: Administrative Costs	MDPSC Case No. 8908

(ak) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
MD Incremental Storm Costs	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630, MDPSC Case No. 9670

(al) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Amortization Lives
MD Incremental Storm Costs	5 years

(am) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Amortization Lives
Tax Cuts and Jobs Act	32 years

(an) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
Tax Cuts and Jobs Act	MDPSC Case No. 9630, DEPS Docket No. 20-0149

(ao) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Amortization Lives
MD RM54 Recovery	3 years

(ap) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
MD RM54 Recovery	MDPSC Case No. 9630

(aq) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
MD Electric Vehicle	MDPSC Case No. 9478

(ar) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
DE Incremental COVID-19 Cost	DEPS Docket No. 20-0286

(as) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
MD Incremental COVID-19 Cost	MDPSC Case No. 9670

(at) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Amortization Lives
MD Incremental COVID-19 Cost	5 years

(au) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
DE Electric Vehicle	DEPS Docket No. 17-1094

(av) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

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

Description of Other Regulatory Assets	MDPSC Case No.	Rate Order Docket Number or Recovery Mechanism
MD Battery Storage	MDPSC Case No. 9619	
(aw) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets	MDPSC Case No. 9156	Rate Order Docket Number or Recovery Mechanism
MD Dynamic Pricing - Critical Peak Rebate Credits	MDPSC Case No. 9156	
(ax) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets		
DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:		
Description of Other Regulatory Assets	MDPSC Final Order No. 90272	Rate Order Docket Number or Recovery Mechanism
MD Incremental IJIA Costs	MDPSC Final Order No. 90272	
(ay) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following discusses the regulatory asset balance sheet reclass:		
\$ 15,696,882	recorded to account 254 - reclass consistent with regulatory recovery position, included in DE Deferred Fuel Costs-Gas line 9, pg. 278	
(az) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$ 131,275	recorded to account 236 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability	
2,022,743	recorded to account 242 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability	
1,195,172	recorded to account 923	
\$ 3,349,190	Total	
(ba) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following discusses the regulatory asset balance sheet reclass:		
\$ 706,738	recorded to account 108 - Asset Retirement Obligation Settlement Cost Activity	
(bb) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$ 5,320,653	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Transmission Service Revenue line 20, pg. 278	
29,906,975	recorded to account 456.1	
\$ 35,227,628	Total	
(bc) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$ 34,300,612	recorded to account 254 - Reclass consistent with regulatory recovery position, included in DE Renewable Portfolio Surcharge Deferral line 8, pg. 278	
3,056,081	recorded to account 407.3	
\$ 37,356,693	Total	
(bd) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "242":		
\$ 475,085	recorded to account 242 - Derivative unrealized loss recorded to B/S per ASC 815	
(be) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$ 883,892	recorded to account 144 - Relief of Regulatory Asset through Accounts Receivable Reserve adjustments	
712,492	recorded to account 232 - Relief of Regulatory Asset through Third Party Supplier Discount	
428,457	recorded to account 253	
120	recorded to account 431	
906	recorded to account 557	
\$ 2,025,867	Total	
(bf) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$ 765,132	recorded to account 144 - Relief of Regulatory Asset through Accounts Receivable Reserve adjustments	
1,095,734	recorded to account 232 - Relief of Regulatory Asset through Third Party Supplier Discount	
\$ 1,860,866	Total	
(bg) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$ 3,940,785	recorded to account 407.3	
69,811	recorded to account 923	
\$ 4,010,596	Total	
(bh) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$ 636,270	recorded to account 407.3	
70,502	recorded to account 923	
\$ 706,772	Total	
(bi) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "254":		
\$ 425,720	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Interest line 6, pg. 278	
(bj) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$ 11,343,227	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Energy line 3, pg. 278	
2,098,893	recorded to account 407.3	
\$ 13,442,120	Total	
(bk) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$ 3,607,319	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Transmission line 4, pg. 278	
2,510,627	recorded to account 407.3	

\$	6,117,946	Total
(bl) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	2,930,884	recorded to account 254 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Administrative Costs line 5, pg. 278
	784,666	recorded to account 407.3
\$	3,715,550	Total
(bm) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	5,186	recorded to account 408.1
	7,713	recorded to account 588
	1,052,621	recorded to account 593
	15,284	recorded to account 903
	484	recorded to account 908
\$	1,081,288	Total
(bn) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	625,897	recorded to account 407.3
	486,153	recorded to account 923
\$	1,112,050	Total
(bo) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	2,039	recorded to account 107 - Account correction
	5,600	recorded to account 146 - Account correction
	56,040	recorded to account 232 - Payable electric vehicle rebates and admin costs
\$	63,679	Total
(bp) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged		
The following are the individual components of "Various":		
\$	320,238	recorded to account 407.3
	52,045	recorded to account 407.4
\$	372,283	Total

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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MISCELLANEOUS DEFERRED 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		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Prepaid Pension Costs	157,464,791	1,258,210	various	6,153,020	152,569,981
2	LT Customer Payment Receivables	85,945		143	28,698	57,247
3	LT Receivable from PJM	1,270,606		143	345,448	925,158
4	Other A/R Worker Compensation	1,200,876	271,914	various	291,334	1,181,456
5	Other	57,001	391,672	various	442,305	6,368
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	160,079,219				154,740,210

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged

Prepaid Pension Cost is offset in Accounts 228.3, 926, 107, and 108.

(b) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged

(c) Concept: DecreaseInMiscellaneousDeferredExpenseAccountCharged

Other is various accounts for minor amounts.

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	134,687,921	124,229,077
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	134,687,921	124,229,077
9	Gas		
10	Gas	16,492,459	15,344,628
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	16,492,459	15,344,628
17.1	AMT Credit / Other		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	151,180,380	139,573,705

Notes

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Account 190 Activity					
410.1 Debits	\$	11,339,530			
411.1 Credits		(13,851,711)			
Net Debits/(Credits)	\$	(2,512,181)			
Account 190 Activity					
410.2 Debits	\$	398,632			
411.2 Credits		—			
Net Debits/(Credits)	\$	398,632			
Account 190 Activity B/S Only					
410 Debits	\$	—			
411 Credits		(13,720,224)			
Net Debits/(Credits)	\$	(13,720,224)			
Net Change	\$	(11,606,675)			
190					
Accrued Benefits	\$	1,125,129	Gas	183,160	Total 1,308,289
Accrued Bodily Injuries		409,376		66,643	476,019
Accrued Bonuses & Incentives		2,199,707		358,092	2,557,799
Accrued Environmental Liability		134,811		21,946	156,757
Accrued Legal		53,033		8,633	61,666
Accrued OPEB		3,223,560		524,766	3,748,326
Accrued Other Expenses		1,823,114		296,786	2,119,900
Accrued Payroll Taxes - AIP		163,132		26,556	189,688
Accrued Severance		16,401		2,670	19,071
Accrued Vacation		250,914		40,846	291,760
Accrued Worker's Compensation		819,600		133,423	953,023
Allowance for Doubtful Accounts		6,180,752		1,006,169	7,186,921
Asset Retirement Obligation		4,089,949		665,806	4,755,755
Charitable Contribution Carryforward		71,758		11,682	83,440

1	Conversion								
2									
3									
4									
5	Total								

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ 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 152, filed with the Securities and Exchange Commission for the year ended December 31, 2022.

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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	679,143,653
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	147,771,356
16	Ending Balance Amount	826,915,009
17	Historical Data - Other Paid in Capital	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	828,253,405

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14	3/30/2051		125,000,000		951,593			03/30/2021	03/30/2051	03/30/2021	03/30/2051	125,000,000	4,050,000
15	3.06% First Mortgage Bonds due 2/15/2052		125,000,000		966,687			^(a) 02/15/2022	02/15/2052	02/15/2022	02/15/2052	125,000,000	3,357,500
16	Tax Exempt Bonds		78,400,000		851,895			07/01/2020	07/01/2025	07/01/2020	07/01/2025	78,400,000	823,201
17	Subtotal		1,907,230,000		17,534,980	(5,039,250)	810,500					1,907,230,000	66,439,431
18	Reacquired Bonds (Account 222)												
19													
20													
21													
22	Subtotal												
23	Advances from Associated Companies (Account 223)												
24													
25													
26													
27	Subtotal												
28	Other Long Term Debt (Account 224)												
29	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
30	Subtotal		10,000,000									10,000,000	772,000
33	TOTAL		1,917,230,000									1,917,230,000	67,211,431

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FOOTNOTE DATA			

^(a) Concept: NominalDateOfIssue
\$125 million of First Mortgage Bonds were issued on February 15, 2022.
^(b) Concept: InterestExpenseOnLongTermDebtIssued
The difference between the total interest reported in column (m) and the balances in accounts 427 and 430 is \$18,199, which represents Service Company related interest from money pool transactions and credit facility commitment fees each of which are reported in account 430.

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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 filed, 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)	168,172,158
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	13,949,526
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Attached Footnote Data	(192,280,051)
27	Federal Tax Net Income	(10,158,367)
28	Show Computation of Tax:	
29	Federal Income Tax at 21%	(2,133,257)
30	Net Operating Loss Utilized	
31	2022 Discrete Adjustments	525,257
32	Income Tax Credits	(1,065,017)
33	TOTAL	(2,673,017)
34	Federal Income Tax Acct 409.10	(1,854,398)
35	Federal Income Tax Acct 409.20	(818,619)
36	Total	(2,673,017)

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FOOTNOTE DATA			

[a] Concept: DeductionsOnReturnNotChargedAgainstBookIncome	
Net Income for the Year (Page 117)	\$ 168,172,158
Federal Income Taxes	(1,062,434)
State Income Taxes	15,011,960
Pre-tax Book Income	<u>\$ 182,121,684</u>
Increase (Decrease) in Taxable Income Resulting From:	
Removal Costs	\$ (37,176,998)
Mixed Service Costs	(79,295,406)
Repair Allowance - Unit of Property	(128,782,071)
Bonus Depreciation	—
Depreciation	58,456,645
CIAC	5,424,162
AFUDC Equity	(7,224,373)
AFUDC Debt	(2,823,221)
Capitalized Interest	5,237,522
Gain/Loss on Disposition of Property	(663,846)
Other (Property)	(3,557,653)
Regulatory Assets & Liabilities	3,054,753
Pension/OPEB/SERP	105,470
Accrued Liabilities	(3,763,939)
Merger Commitment Deferrals	(1,760,560)
State Income Taxes Deductible	—
Deferred Revenue	(744,834)
Other (Net)	1,234,298
Total Schedule M's	<u>\$ (192,280,051)</u>
Federal Taxable Income	(10,158,367)
Computation of Federal Income Tax:	
Federal Income Tax on Current Year Income (21%)	\$ (2,133,257)
Net Operating Loss Utilized	—
2022 Discrete Adjustments	525,257
Income Tax Credits	(1,065,017)
Federal Income Tax	<u>\$ (2,673,017)</u>
Federal Income Tax Account 409.10	\$ (1,854,398)
Federal Income Tax Account 409.20	(818,619)
Total	<u>\$ (2,673,017)</u>

Additional information in response to Instruction 2, Page 261:

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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	2022	0	0	1,091,018	1,091,018		0		1,091,018				
6	Reg Asset Assessment - Electric	Other Taxes	DE	2022	1,730,896	0	1,611,873	1,578,606		1,764,163		1,611,873				
7	Reg Asset Assessment - Gas	Other Taxes	DE	2022	31,797	0	649,420	522,368		158,849						649,420
8	Environmental Surcharge	Other Taxes	MD	2022	55,428	0	600,561	600,911		55,078		600,561				
9	Other Taxes	Other Taxes	MD	2022	0					0						
10	GRT/Professional Services - Electric	Other Taxes	DE	2022	29,929	0	640,126	614,846		55,209		640,126				
11	GRT/Professional Services - Electric Reserve	Other Taxes	DE	2022	195,175	0	(135,098)	43,412		16,665		(135,098)				
12	GRT/Professional Services - Gas	Other Taxes	DE	2022	1,841	0	108,987	108,811		2,017						108,987
13	Public Utility Tax - Electric	Other Taxes	DE	2022	564,141	0	8,015,657	7,873,603		706,195		8,015,657				
14	Public Utility Tax - Gas	Other Taxes	DE	2022	267,761	0	2,864,885	2,760,264		372,382						2,864,885
15	Subtotal Other Tax				2,876,968		15,447,429	15,193,839		3,130,558		11,824,137				3,623,292
16	Property Taxes	Property Tax	MD	2022		10,055,283	20,751,628	25,211,967	2,805,993	0	11,709,629	20,751,628				
17	Property Taxes - Other	Property Tax	MD	2022	28,657	0		(33,365)	(31,011)	31,011						
18	Property Taxes	Property Tax	DE	2022	0	10,383,565	20,650,601	22,209,762	958,174	0	10,984,552	12,531,225				8,119,376
19	Property Taxes	Property Tax	VA	2022	0	0	167,359	168,467	1,108	0		167,359				
20	Property Taxes	Property Tax	WV	2022	0	0	5,373	5,373		0						5,373
21	Property Taxes	Property Tax	MS	2022	0	0	3,501	3,501		0						3,501
22	Property Taxes	Property Tax	NJ	2022	0	0	635,477	635,477		0						635,477
23	Property Taxes	Property Tax	PA	2022	0	40,182		116,090	113,557	0	42,715					
24	Subtotal Property Tax				28,657	20,479,030	42,213,939	48,317,272	3,847,821	31,011	22,736,896	33,450,212				8,763,727
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	2022	0	0	41,743	41,743		0		41,743		
28	Use Tax	Sales And Use Tax	MD	2022	213,073	0		(634,089)		847,162				
29	Use Tax Reserve	Sales And Use Tax	MD	2022	639,517	0	32,555	4,796		667,276		32,555		
30	Use Tax	Sales And Use Tax	VA	2022	19,112	0		(138,404)		157,516				
31	Subtotal Sales And Use Tax				871,702	0	74,298	(725,954)		1,671,954	0	74,298		
32	Federal Income Tax	Income Tax	Fed	2022	460,213	0	(2,673,017)	(3,227,820)	(338,815)	676,201		(3,464,307)		791,290
33	State Income Tax - Delaware	Income Tax	DE	2022	993,441	0	99,676	1,097,914	4,797			89,708		9,968
34	State Income Tax - Maryland	Income Tax	MD	2022	0	0				0				
35	Subtotal Income Tax				1,453,654	0	(2,573,341)	(2,129,906)	(334,018)	676,201	0	(3,374,599)		801,258
36	Heavy Highway Excise Tax	Excise Tax	Fed	2022	0		25,025	25,025		0		21,521		3,504
37	Subtotal Excise Tax				0		25,025	25,025		0	0	21,521		3,504
38	Subtotal Fuel Tax				0	0				0	0			
39	Subtotal Federal Insurance Tax				0	0				0	0			
40	Franchise Tax	Franchise Tax	MD	2022	93,071		8,833,513	8,844,424		82,160		8,833,513		
41	Wilmington Franchise Tax	Franchise Tax	DE	2022	679,678	0	872,315	691,050		860,943		872,315		
42	Wilmington Franchise Tax Reserve	Franchise Tax	DE	2022	112,634	0	30,674	143,308				30,674		
43	Subtotal Franchise Tax				885,383		9,736,502	9,678,782		943,103	0	9,736,502		
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	Various	2022	3,814,609	0	3,899,587	6,474,981		1,239,215		3,321,878		577,710
52	Subtotal Payroll Tax				3,814,609	0	3,899,587	6,474,981		1,239,215	0	3,321,878		577,710
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				9,930,973	20,479,030	68,823,439	76,834,039	3,513,803	7,692,042	22,736,896	55,053,949		13,769,491

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FOOTNOTE DATA			

(a) Concept: TaxYear	
The tax year for federal income taxes accrued, prepaid and charged during the year also applies to tax years 2016-2021.	
(b) Concept: TaxYear	
The tax year for state income taxes accrued, prepaid and charged during the year also applies to tax years 2016-2021.	
(c) Concept: TaxAdjustments	
Adjustments to Property Taxes Reclassification to FERC Account 184 Property Tax Reclassification	Amount \$ 2,774,982 31,011

Total Adjustments to Maryland Property Taxes	\$ 2,805,993
(d) Concept: TaxAdjustments	
Adjustments to Property Taxes - Other	Amount
Property Tax Reclassification	\$ (31,011)
Total Adjustments to Property Taxes - Other	\$ (31,011)
(e) Concept: TaxAdjustments	
Adjustments to Property Taxes	Amount
Reclassification to FERC Account 184	\$ 958,174
Total Adjustments to Property Taxes	\$ 958,174
(f) Concept: TaxAdjustments	
Adjustments to Property Taxes	Amount
Reclassification to FERC Account 184	\$ 1,108
Total Adjustments to Property Taxes	\$ 1,108
(g) Concept: TaxAdjustments	
Adjustments to Property Taxes	Amount
Reclassification to FERC Account 184	\$ 113,557
Total Adjustments to Property Taxes	\$ 113,557
(h) Concept: TaxAdjustments	
Adjustments to Federal Income Tax	Amount
Reclassification to FERC Account 143	\$ (338,815)
Total Adjustments to Federal Income Tax	\$ (338,815)
(i) Concept: TaxAdjustments	
Adjustments to State Income Tax	Amount
Reclassification to FERC Account 143	\$ 4,797
Total Adjustments to State Income Tax	\$ 4,797

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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		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%	7,136			411.4	1,466		5,670		
4	7%	350,061			411.4	71,904		278,157		
5	10%	917,494			411.4	188,456		729,038		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,274,691				261,826		1,012,865		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										
11	10% Gas Utility	104,251				32,742		71,509		
12	Total Other	104,251				32,742		71,509		
13	Account 255	1,378,942				294,568		1,084,374		
47	OTHER TOTAL									
48	GRAND TOTAL	1,378,942						1,084,374		

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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												

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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)		
			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)	Debits		Credits				
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)			
1	Account 282												
2	Electric	768,935,653	51,632,193	33,645,284						VARIOUS	30,206,618	817,129,180	
3	Gas	85,437,295	5,733,588	5,956,597						VARIOUS	5,577,845	90,792,131	
4	Other (Specify)												
5	Total (Total of lines 2 thru 4)	854,372,948	57,365,781	39,601,881							35,784,463	907,921,311	
6													
7													
8													
9	TOTAL Account 282 (Total of Lines 5 thru 8)	854,372,948	57,365,781	39,601,881							35,784,463	907,921,311	
10	Classification of TOTAL												
11	Federal Income Tax	619,436,007	39,835,840	38,548,346						VARIOUS	34,684,056	655,407,557	
12	State Income Tax	234,936,941	17,529,941	1,053,535						VARIOUS	1,100,407	252,513,754	
13	Local Income Tax												

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FOOTNOTE DATA

<u>(a)</u> Concept: AccumulatedDeferredIncomeTaxesOtherProperty			
282	Electric	Gas	Total
Plant Deferred Taxes - ML FAS 109	\$ 303,293,687	\$ 33,699,299	\$ 336,992,986

Plant Deferred Taxes - FAS 109	484,817,196	53,868,577	538,685,773
CIAC	(18,949,367)	(2,105,485)	(21,054,852)
AFUDC Equity	10,405,266	1,156,141	11,561,407
Plant Deferred Taxes - Flow-through	6,682,979	742,553	7,425,532
Maryland Subtraction Modification	(17,314,108)	(1,923,790)	(19,237,898)
Total	\$ 768,935,653 \$	85,437,295 \$	854,372,948

(b) Concept: AccumulatedDeferredIncomeTaxesOtherProperty

282	Electric	Gas	Total
Plant Deferred Taxes - ML FAS 109	304,911,781 \$	33,879,087 \$	338,790,868
Plant Deferred Taxes - FAS 109	530,807,239	58,978,582	589,785,821
CIAC	(19,875,242)	(2,208,360)	(22,083,602)
AFUDC Equity	11,818,466	1,313,163	13,131,629
Plant Deferred Taxes - Flow-through	6,635,369	737,263	7,372,632
Maryland Subtraction Modification	(17,168,433)	(1,907,604)	(19,076,037)
Total	\$ 817,129,180 \$	90,792,131 \$	907,921,311

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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)
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Electric	88,590,453	6,366,481	5,265,637							89,691,297
9	TOTAL Electric (Total of lines 3 thru 8)	88,590,453	6,366,481	5,265,637							89,691,297
10	Gas										
11	Gas	10,736,185	884,628	818,388							10,802,425
17	TOTAL Gas (Total of lines 11 thru 16)	10,736,185	884,628	818,388							10,802,425
18	TOTAL Other										
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	99,326,638	7,251,109	6,084,025							100,493,722
20	Classification of TOTAL										
21	Federal Income Tax	68,863,841	5,027,244	4,218,097							69,672,988
22	State Income Tax	30,462,797	2,223,865	1,865,928							30,820,734
23	Local Income Tax										

NOTES

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

283	Electric	Gas	Total
Accrued Property Taxes	\$ 5,079,370 \$	826,874 \$	5,906,244
Asset Retirement Obligation	—	—	—
Materials Reserve	(106,532)	(17,342)	(123,874)
Other Deferred Debits	1,178,630	191,870	1,370,500
Pension Asset	37,667,196	6,131,869	43,799,065
Regulatory Asset	40,743,482	3,299,340	44,042,822
Regulatory Asset - Accrued Vacation	798,276	129,952	928,228
Renewable Energy Credits	2,163,493	—	2,163,493
Unamortized Loss on Reacquired Debt	1,066,538	173,622	1,240,160
Total	\$ 88,590,453 \$	10,736,185 \$	99,326,638

(b) Concept: AccumulatedDeferredIncomeTaxesOther

283	Electric	Gas	Total
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Accrued Property Taxes	\$	5,519,353	\$	898,499	\$	6,417,852
Asset Retirement Obligation		522,659		85,084		607,743
Materials Reserve		(108,286)		(17,628)		(125,914)
Other Deferred Debits		1,554,537		253,064		1,807,601
Pension Asset		36,364,902		5,919,868		42,284,770
Regulatory Asset		41,830,735		3,388,387		45,219,122
Regulatory Asset - Accrued Vacation		786,480		128,032		914,512
Renewable Energy Credits		2,317,186		—		2,317,186
Unamortized Loss on Reacquired Debt		903,731		147,119		1,050,850
Total	\$	89,691,297	\$	10,802,425	\$	100,493,722

FERC FORM NO. 1 (ED. 12-96)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	SFAS 109 Regulatory Liability: Electric	315,829,064	various	44,554,218		271,274,846
2	SFAS 109 Regulatory Liability: Gas	38,543,903	various	4,950,468		33,593,435
3	Maryland SOS: Energy		various	12,983,996	12,983,996	
4	Maryland SOS: Transmission		various	4,366,449	4,366,449	
5	Maryland SOS: Administrative Costs		various	3,076,865	3,076,865	
6	Delaware SOS: Interest	318,784	various	723,869	405,085	
7	DE Qualified Fuel Cell Facility	7,574,467	various	29,394,059	27,216,771	5,397,179
8	DE Renewable Portfolio Surcharge Deferral		various	35,677,240	45,257,335	9,580,095
9	DE Deferred Fuel Costs-Gas	1,392,552	various	29,406,848	34,614,423	6,600,127
10	DE Distribution Rate Reserve	178,030	various	178,030		
11	DE Gas Rate Reserve				622,491	622,491
12	MD Dynamic Pricing - Critical Peak Rebate Credits		407.3	95,634	640,745	545,111
13	Tax Cuts and Jobs Act	1,523,842			167,670	1,691,512
14	DSM Direct Load Control Program-MD	561,370	407.3	1,457,550	1,665,629	769,449
15	DSM-Energy Efficiency Products-MD	1,252,667	407.3	1,252,666	1,767,147	1,767,148
16	MD Bill Stabilization Adjustment Deferral	2,624,735	456	17,367,548	20,332,436	5,589,623
17	SOS Deferral for FERC 494 Settlement	1,685,484	407.3	461,443	163,687	1,387,728
18	DE Elec Distribution System Improvement Charge	859,880	various	892,592	32,712	
19	DE DSM - Energy Efficiency	88,113	various	86,918	112,857	114,052
20	Transmission Service Revenue		various	5,440,437	6,893,502	1,453,065
21	DE Incremental COVID-19 Cost	2,961,668				2,961,668
22	MD Incremental COVID-19 Cost	60,992	426.5	279,477	391,134	172,649
23	Chestertown Substation Land Gain	58,988	421.1	38,296		20,692

24	Vegetation Management Spending	47,943	various	54,343	6,400	
25	PHISCO Gross Receipt Settlement	410,263				410,263
41	TOTAL	375,972,745		192,738,946	160,717,334	343,951,133

FERC FORM NO. 1 (REV 02-04)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
Maryland SOS: Energy	MDPSC Case No. 8908	
(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
Maryland SOS: Transmission	MDPSC Case No. 8909	
(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
Maryland SOS: Administrative Costs	MDPSC Case No. 8908	
(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
Delaware SOS: Interest	DEPSC Docket No. 04-391	
(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
DE Qualified Fuel Cell Facility	DEPSC Docket No. 12-173-04	
(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
DE Renewable Portfolio Surcharge Deferral	DEPSC Regulation Docket No. 56	
(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
DE Deferred Fuel Costs-Gas	DEPSC Docket No. 19-0556	
(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
DE Distribution Rate Reserve	DEPSC Docket No. 20-0149	
(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
DE Gas Rate Reserve	DEPSC Docket No. 22-0002	
(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
MD Dynamic Pricing - Critical Peak Rebate Credits	MDPSC Case No. 9156	
(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	
Tax Cuts and Jobs Act	MDPSC Case No. 9473, MDPSC Case No. 9630	
(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism	

DSM Direct Load Control Program-MD		MDPSC Case No. 9156
(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
DSM Energy Efficiency Products-MD	MDPSC Case No. 9156	
(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
MD Bill Stabilization Adjustment Deferral	MDPSC Case No. 9092, MDPSC Case No. 9093	
(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL amortizes its regulatory liabilities in account 254 based on the following amortization periods:		
Description of Other Regulatory Liabilities		Amortization Lives
SOS Deferral for FERC 494 Settlement	10 years	
(p) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
SOS Deferral for FERC 494 Settlement	FERC Docket No. EL05-121-009	
(q) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
DE Elec Distribution System Improvement Charge	DEPSC Regulation Docket No. 64	
(r) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
DE DSM - Energy Efficiency	DEPSC Docket No. 17-0985	
(s) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
Transmission Service Revenue	FERC Docket No. ER05-515	
(t) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
DE Incremental COVID-19 Cost	DEPSC Docket No. 20-0286	
(u) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
MD Incremental COVID-19 Cost	MDPSC Case No. 9670	
(v) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL amortizes its regulatory liabilities in account 254 based on the following amortization periods:		
Description of Other Regulatory Liabilities		Amortization Lives
MD Incremental COVID-19 Cost	5 years	
(w) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
Chestertown Substation Land Gain	MDPSC Case No. 9630	
(x) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL amortizes its regulatory liabilities in account 254 based on the following amortization periods:		
Description of Other Regulatory Liabilities		Amortization Lives
Chestertown Substation Land Gain	3 years	
(y) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities		
DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:		
Description of Other Regulatory Liabilities		Rate Order Docket Number or Recovery Mechanism
Vegetation Management Spending	MDPSC Case No. 9353	
(z) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment		
The following are the individual components of "Various":		
\$	12,348,202	recorded to account 190
	1,435,322	recorded to account 282
	30,770,694	recorded to account 410/411
\$	44,554,218	Total
(aa) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment		

<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>1,372,022</td> <td>recorded to account 190</td> </tr> <tr> <td></td> <td>159,480</td> <td>recorded to account 282</td> </tr> <tr> <td></td> <td>3,418,966</td> <td>recorded to account 410/411</td> </tr> <tr> <td>\$</td> <td>4,950,468</td> <td>Total</td> </tr> </table>	\$	1,372,022	recorded to account 190		159,480	recorded to account 282		3,418,966	recorded to account 410/411	\$	4,950,468	Total
\$	1,372,022	recorded to account 190										
	159,480	recorded to account 282										
	3,418,966	recorded to account 410/411										
\$	4,950,468	Total										
(ab) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>11,343,227</td> <td>recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Energy, line 26, page 232</td> </tr> <tr> <td></td> <td>1,640,769</td> <td>recorded to account 407.3</td> </tr> <tr> <td>\$</td> <td>12,983,996</td> <td>Total</td> </tr> </table>	\$	11,343,227	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Energy, line 26, page 232		1,640,769	recorded to account 407.3	\$	12,983,996	Total			
\$	11,343,227	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Energy, line 26, page 232										
	1,640,769	recorded to account 407.3										
\$	12,983,996	Total										
(ac) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>3,607,319</td> <td>recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Transmission, line 27, page 232</td> </tr> <tr> <td></td> <td>759,130</td> <td>recorded to account 407.3</td> </tr> <tr> <td>\$</td> <td>4,366,449</td> <td>Total</td> </tr> </table>	\$	3,607,319	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Transmission, line 27, page 232		759,130	recorded to account 407.3	\$	4,366,449	Total			
\$	3,607,319	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Transmission, line 27, page 232										
	759,130	recorded to account 407.3										
\$	4,366,449	Total										
(ad) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>2,930,884</td> <td>recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Administrative Costs, line 28, page 232</td> </tr> <tr> <td></td> <td>145,981</td> <td>recorded to account 407.3</td> </tr> <tr> <td>\$</td> <td>3,076,865</td> <td>Total</td> </tr> </table>	\$	2,930,884	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Administrative Costs, line 28, page 232		145,981	recorded to account 407.3	\$	3,076,865	Total			
\$	2,930,884	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Maryland SOS: Administrative Costs, line 28, page 232										
	145,981	recorded to account 407.3										
\$	3,076,865	Total										
(ae) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>425,720</td> <td>recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Interest, line 25, page 232</td> </tr> <tr> <td></td> <td>298,149</td> <td>recorded to account 431</td> </tr> <tr> <td>\$</td> <td>723,869</td> <td>Total</td> </tr> </table>	\$	425,720	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Interest, line 25, page 232		298,149	recorded to account 431	\$	723,869	Total			
\$	425,720	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Delaware SOS: Interest, line 25, page 232										
	298,149	recorded to account 431										
\$	723,869	Total										
(af) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>194,805</td> <td>recorded to account 144 - Reclass of reserve on DE Qualified Fuel Cell activity</td> </tr> <tr> <td></td> <td>29,198,409</td> <td>recorded to account 407.3</td> </tr> <tr> <td></td> <td>845</td> <td>recorded to account 928</td> </tr> <tr> <td>\$</td> <td>29,394,059</td> <td>Total</td> </tr> </table>	\$	194,805	recorded to account 144 - Reclass of reserve on DE Qualified Fuel Cell activity		29,198,409	recorded to account 407.3		845	recorded to account 928	\$	29,394,059	Total
\$	194,805	recorded to account 144 - Reclass of reserve on DE Qualified Fuel Cell activity										
	29,198,409	recorded to account 407.3										
	845	recorded to account 928										
\$	29,394,059	Total										
(ag) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>34,300,612</td> <td>recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE Renewable Energy Portfolio Standards, line 5, page 232</td> </tr> <tr> <td></td> <td>1,376,628</td> <td>recorded to account 407.3</td> </tr> <tr> <td>\$</td> <td>35,677,240</td> <td>Total</td> </tr> </table>	\$	34,300,612	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE Renewable Energy Portfolio Standards, line 5, page 232		1,376,628	recorded to account 407.3	\$	35,677,240	Total			
\$	34,300,612	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE Renewable Energy Portfolio Standards, line 5, page 232										
	1,376,628	recorded to account 407.3										
\$	35,677,240	Total										
(ah) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>15,696,882</td> <td>recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE Deferred Fuel Costs-Gas, line 1, page 232</td> </tr> <tr> <td></td> <td>5,180,166</td> <td>recorded to account 431</td> </tr> <tr> <td></td> <td>8,529,800</td> <td>recorded to account 805.1</td> </tr> <tr> <td>\$</td> <td>29,406,848</td> <td>Total</td> </tr> </table>	\$	15,696,882	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE Deferred Fuel Costs-Gas, line 1, page 232		5,180,166	recorded to account 431		8,529,800	recorded to account 805.1	\$	29,406,848	Total
\$	15,696,882	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE Deferred Fuel Costs-Gas, line 1, page 232										
	5,180,166	recorded to account 431										
	8,529,800	recorded to account 805.1										
\$	29,406,848	Total										
(ai) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>10,515</td> <td>recorded to account 431</td> </tr> <tr> <td></td> <td>167,515</td> <td>recorded to account 442</td> </tr> <tr> <td>\$</td> <td>178,030</td> <td>Total</td> </tr> </table>	\$	10,515	recorded to account 431		167,515	recorded to account 442	\$	178,030	Total			
\$	10,515	recorded to account 431										
	167,515	recorded to account 442										
\$	178,030	Total										
(aj) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>576,774</td> <td>recorded to account 440</td> </tr> <tr> <td></td> <td>285,012</td> <td>recorded to account 442</td> </tr> <tr> <td></td> <td>30,806</td> <td>recorded to account 444</td> </tr> <tr> <td>\$</td> <td>892,592</td> <td>Total</td> </tr> </table>	\$	576,774	recorded to account 440		285,012	recorded to account 442		30,806	recorded to account 444	\$	892,592	Total
\$	576,774	recorded to account 440										
	285,012	recorded to account 442										
	30,806	recorded to account 444										
\$	892,592	Total										
(ak) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>18,829</td> <td>recorded to account 407.3</td> </tr> <tr> <td></td> <td>68,089</td> <td>recorded to account 908</td> </tr> <tr> <td>\$</td> <td>86,918</td> <td>Total</td> </tr> </table>	\$	18,829	recorded to account 407.3		68,089	recorded to account 908	\$	86,918	Total			
\$	18,829	recorded to account 407.3										
	68,089	recorded to account 908										
\$	86,918	Total										
(al) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>5,320,653</td> <td>recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Transmission Service Revenue, line 4, page 232</td> </tr> <tr> <td></td> <td>119,784</td> <td>recorded to account 407.3</td> </tr> <tr> <td>\$</td> <td>5,440,437</td> <td>Total</td> </tr> </table>	\$	5,320,653	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Transmission Service Revenue, line 4, page 232		119,784	recorded to account 407.3	\$	5,440,437	Total			
\$	5,320,653	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Transmission Service Revenue, line 4, page 232										
	119,784	recorded to account 407.3										
\$	5,440,437	Total										
(am) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment												
<p>The following are the individual components of "Various":</p> <table> <tr> <td>\$</td> <td>52,670</td> <td>recorded to account 254 - Reclassed to the MD Bill Stabilization Adjustment Deferral</td> </tr> <tr> <td></td> <td>1,673</td> <td>recorded to account 456</td> </tr> <tr> <td>\$</td> <td>54,343</td> <td>Total</td> </tr> </table>	\$	52,670	recorded to account 254 - Reclassed to the MD Bill Stabilization Adjustment Deferral		1,673	recorded to account 456	\$	54,343	Total			
\$	52,670	recorded to account 254 - Reclassed to the MD Bill Stabilization Adjustment Deferral										
	1,673	recorded to account 456										
\$	54,343	Total										

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	749,715,964	693,625,510	5,445,976	5,413,386	479,551	475,020
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	343,035,214	267,852,652	5,160,394	5,022,469	64,479	63,797
5	Large (or Ind.) (See Instr. 4)	29,296,177	19,146,393	1,452,063	1,523,742	268	285
6	(444) Public Street and Highway Lighting	14,573,086	14,404,593	43,794	45,218	599	606
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	1,136,620,441	995,029,148	12,102,227	12,004,815	544,897	539,708
11	(447) Sales for Resale	22,705,465	10,977,167	356,069	311,240		
12	TOTAL Sales of Electricity	1,159,325,906	1,006,006,315	12,458,296	12,316,055	544,897	539,708
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	1,159,325,906	1,006,006,315	12,458,296	12,316,055	544,897	539,708
15	Other Operating Revenues						
16	(450) Forfeited Discounts	2,355,260	1,719,006				
17	(451) Miscellaneous Service Revenues	263,891	320,222				
18	(453) Sales of Water and Water Power						
19	(454) Rent from Electric Property	5,698,343	6,131,437				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	10,359,133	15,362,130				
22	(456.1) Revenues from Transmission of Electricity of Others	192,537,781	186,693,091				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	211,214,408	210,225,886				
27	TOTAL Electric Operating Revenues	1,370,540,314	1,216,232,201				

Line12, column (b) includes \$ 9,495,850 of unbilled revenues.
 Line12, column (d) includes 21,600 MWH relating to unbilled revenues

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
FOOTNOTE DATA			

(a) Concept: OtherElectricRevenue

Amounts over \$250,000		
MD Bill Stabilization Adjustment	\$	(466,679)
MD Calendar Revenue Normalization		(2,445,539)
Intercompany Revenue		3,934,974
Intracompany Power Sales		1,148,425
Price Responsive Demand Credit		3,234,096
RPM Auction		532,779
Intercompany Power Sales		790,150
RPM Seasonal Capacity Performance Auction		1,549,596
Consolidated Billing and Account Management Fees		447,403
Auction Revenue Rights		982,628
Transmission Losses		314,904

(b) Concept: OtherElectricRevenue

Amounts over \$250,000		
MD Bill Stabilization Adjustment	\$	(2,513,896)
MD Calendar Revenue Normalization		1,374,606
Intercompany Revenue		4,857,586
Intracompany Power Sales		858,764
Price Responsive Demand Credit		5,112,633
Intercompany Power Sales		793,619
Net Metering		1,348,239
RPM Seasonal Capacity Performance Auction		1,481,729
RPM Auction		906,420
Consolidated Billing and Account Management Fees		475,889
DE Interconnection fees		566,456

(c) Concept: MegawattHoursSoldSalesForResale

DPL had a revenue adjustment recorded in the 2021 reporting year related to updated information received for 2020 sales for resales (account 447). The reported sales from PECO Energy for 2020 are reduced by 880 MWh. MWhs sold as reported here on this page includes only those sales made during the 2021 reporting year.

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

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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)
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41					
42					
43					
44					
45					
46	TOTAL				

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: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	4,304,498	611,306,174	393,367	10,943	0.1420
3	Residential Time Of Use - Non Demand	1,734	224,206	130	13,338	0.1293
4	Outdoor Lighting - Residential	6,271	2,016,699	4,227	1,484	0.3216
5	Residential Space Heating	1,101,402	129,276,235	85,494	12,883	0.1174
6	Residential Time-of-Use (TOU) Pilot	5,829	916,639	549	10,617	0.1573
7	Plug in Vehicle - Residential	161	23,302	12	13,417	0.1446
8	Small General Service					
9	Medium General Service					
10	Unbilled Revenue	26,081	6,355,046			0.2437
11	DE Interim rates subject to refund					

12	DE DSIC revenue subject to refund		576,775			
13	Adjustments - Duplicate Customers			(4,228)		
14	Energy Credits		(979,112)			
41	TOTAL Billed Residential Sales	5,419,895	743,360,918	479,551	11,302	0.1372
42	TOTAL Unbilled Rev. (See Instr. 6)	26,081	6,355,046			0.2437
43	TOTAL	5,445,976	749,715,964	479,551	11,356	0.1377

FERC FORM NO. 1 (ED. 12-95)

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SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	1,061,101	130,955,812	53,247	19,928	0.1234
3	Unmetered Small General Service	344	81,100	220	1,564	0.2358
4	Separately Metered Space Heating	78,486	5,490,105	2,347	33,441	0.0700
5	Separately Metered Water Heating	574	52,301	98	5,857	0.0911
6	Medium General Service	1,178,208	85,773,018	8,903	132,338	0.0728
7	Unmetered Medium General Service	36	17,586	15	2,400	0.4885
8	Large General Service	788,541	37,848,813	533	1,479,439	0.0480
9	General Services Primary	2,028,902	67,367,191	567	3,578,310	0.0332
10	Commercial Outdoor Lighting	12,156	4,301,962	3,784	3,212	0.3539
11	Commercial Outdoor Recreational Lighting	1,158	170,676	78	14,846	0.1474
12	Telecommunications Network Svc	3,572	255,307	925	3,862	0.0715
13	Residential			0		
14	Unbilled Revenue	7,316	3,066,519			0.4192
15	DE Interim rates subject to refund		142,154	0		
16	DE DSIC revenue subject to refund		264,397	0		
17	Public Utility Tax Surcharge Revenue		7,463,201			
18	Adjustments - Duplicate Customers			(6,238)		
19	Energy Credits & Billed BSA		(214,928)	0		
41	TOTAL Billed Small or Commercial	5,153,078	339,968,695	64,479	79,919	0.0660
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	7,316	3,066,519			0.4192
43	TOTAL Small or Commercial	5,160,394	343,035,214	64,479	80,032	0.0665

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SALES OF ELECTRICITY BY RATE SCHEDULES

- 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	5,904	616,918	104	56,769	0.1045
3	Medium General Service	7,886	475,648	38	207,526	0.0603
4	Large General Service	35,941	1,703,223	19	1,891,632	0.0474
5	General Services Primary	798,580	24,584,608	99	8,066,465	0.0308
6	General Services Transmission	615,124	1,233,121	8	76,890,500	0.0020
7	Industrial Outdoor Lighting	284	63,558	46	6,174	0.2238
8	Separately Metered Space Heating	57	2,220	2	28,500	0.0390
9	Unbilled Revenue	(11,713)	56,796			(0.0048)
10	DE Interim rates subject to refund		25,361			
11	DE DSIC revenue subject to refund		20,615			
12	Public Utility Tax Surcharge Revenue		514,109			
13	Adjustments - Duplicate Customers			(48)		
14	Energy Credits					
41	TOTAL Billed Large (or Ind.) Sales	1,463,776	29,239,381	268	5,461,851	0.0200
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(11,713)	56,796			(0.0048)
43	TOTAL Large (or Ind.)	1,452,063	29,296,177	268	5,418,146	0.0202

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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						
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36						
37						
38						
39						
40						
41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	43,878	14,494,646	599	73,252	0.3303
3	DE Interim rates subject to refund					
4	DE DSIC revenue subject to refund		30,806			

5	Unbilled Revenue	(84)	17,489			(0.2082)
6	Public Utility Tax Surcharge Revenue		30,145			
41	TOTAL Billed Public Street and Highway Lighting	43,878	14,555,597	599	73,252	0.3317
42	TOTAL Unbilled Rev. (See Instr. 6)	(84)	17,489			(0.2082)
43	TOTAL	43,794	14,573,086	599	73,112	0.3328

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SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	12,080,627	1,127,124,591	544,898	22,170	0.0933
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	21,600	9,495,850			0.4396
43	TOTAL - All Accounts	12,102,227	1,136,620,441	544,898	22,210	0.0939

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SALES FOR RESALE (Account 447)

- 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).
- 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.
- 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 long-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 seller 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.
- 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).
- 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.
- 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.
- Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
- 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.
- 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.
- Footnote entries as required and provide explanations following all required data.

Line	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff	Average Monthly Billing Demand (MW)	ACTUAL DEMAND (MW)		Megawatt Hours Sold	REVENUE			Total (\$) (h+i+j)
					Average Monthly NCP Demand	Average Monthly CP Demand		Demand Charges	Energy Charges	Other Charges	

No.	(a)	(b)	Number (c)	(d)	(e)	(f)	(g)	(\$)(h)	(\$)(i)	(\$)(j)	(k)
1	PECO Energy	RQ	2				915		40,655		40,655
2	PJM Interconnection	OS	PJM				355,154		22,664,810		22,664,810
15	Subtotal - RQ						915		40,655		40,655
16	Subtotal-Non-RQ						355,154		22,664,810		22,664,810
17	Total						356,069		22,705,465		22,705,465

FERC FORM NO. 1 (ED. 12-90)

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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) Maintenance 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	571,650,949	468,431,276
76.1	(555.1) Power Purchased for Storage Operations	0	
77	(556) System Control and Load Dispatching	55,381	(4,816)
78	(557) Other Expenses	26,867,597	10,903,283
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	598,573,927	479,329,743
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	598,573,927	479,329,743
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	8,332,779	5,489,118
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	601,853	874,662
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	70,069	744
89	(561.5) Reliability, Planning and Standards Development		2,183
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	19,182	(1,011)
93	(562) Station Expenses		
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses		
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	2,300,955	4,502,226
98	(567) Rents		
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	11,324,838	10,867,922
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	6,678	15,013
102	(569) Maintenance of Structures	500,143	1,181,712
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	7,868,351	8,085,250
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	4,428,190	5,972,981
109	(572) Maintenance of Underground Lines		5,804
110	(573) Maintenance of Miscellaneous Transmission Plant	383,922	388,344
111	TOTAL Maintenance (Total of Lines 101 thru 110)	13,187,284	15,649,104
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	24,512,122	26,517,026
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	64,371	2,481
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	64,371	2,481
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)	64,371	2,481
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,579,599	2,312,324
135	(581) Load Dispatching	3,273,053	5,069,765
136	(582) Station Expenses	1,629	4,593
137	(583) Overhead Line Expenses	1,017,580	1,301,093
138	(584) Underground Line Expenses	2,690,603	3,239,239
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	322,924	371,016
140	(586) Meter Expenses	4,248,917	4,820,831
141	(587) Customer Installations Expenses	634,823	583,159
142	(588) Miscellaneous Expenses	18,726,067	17,436,793
143	(589) Rents	1,584,531	1,828,517
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	34,079,726	36,967,330
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,939	25,336
147	(591) Maintenance of Structures	482,050	241,179
148	(592) Maintenance of Station Equipment	5,128,966	5,167,582
148.1	(592.2) Maintenance of Energy Storage Equipment		56,322
149	(593) Maintenance of Overhead Lines	45,053,682	43,653,585
150	(594) Maintenance of Underground Lines	4,290,930	4,967,114
151	(595) Maintenance of Line Transformers	798,422	984,143
152	(596) Maintenance of Street Lighting and Signal Systems	1,785,081	1,405,884
153	(597) Maintenance of Meters	523,366	1,023,885
154	(598) Maintenance of Miscellaneous Distribution Plant	865,580	828,229
155	TOTAL Maintenance (Total of Lines 146 thru 154)	58,931,016	58,353,259
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	93,010,742	95,320,589
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	888,243	1,113,186
161	(903) Customer Records and Collection Expenses	45,087,455	44,120,145

162	(904) Uncollectible Accounts	10,314,159	4,487,061
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	56,289,857	49,720,392
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	10,992,924	11,922,319
169	(909) Informational and Instructional Expenses	156,985	272,653
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	11,149,909	12,194,972
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	3,224,138	3,295,611
182	(921) Office Supplies and Expenses	5,271,821	5,587,918
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	72,230,523	68,823,428
185	(924) Property Insurance	692,197	770,910
186	(925) Injuries and Damages	2,424,052	568,813
187	(926) Employee Pensions and Benefits	6,484,747	6,511,199
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	2,095,257	2,471,744
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	586,529	708,019
192	(930.2) Miscellaneous General Expenses	6,987,014	7,163,038
193	(931) Rents		
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	99,996,278	95,900,680
195	Maintenance		
196	(935) Maintenance of General Plant	(80,103)	256,217
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	99,916,175	96,156,897
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	883,517,103	759,242,100

FERC FORM NO. 1 (ED. 12-93)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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 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.

- 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.
- For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (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.
- Report in column (g) the megawatt-hours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatt-hours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatt-hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
- 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 settled 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.
- 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.
- 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)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges (\$) (k)	Energy Charges (\$) (l)	Other Charges (\$) (m)	Total (k+l+m) of Settlement (\$) (n)
1	PJM Interconnection, LLC	EX	PJM Tariff				370,290				2,690,784	32,632,459	83,763,205	119,086,448
2	AEP Energy Partners, Inc.	OS					91,627					5,432,860		5,432,860
3	Axpo U.S. LLC	OS					855,858					44,529,489		44,529,489
4	Constellation Energy Resources, LLC	OS					1,220,592					69,235,806		69,235,806
5	DTE Energy Trading, Inc.	OS					1,127,553					72,717,823		72,717,823
6	Exelon Generation Company LLC	OS					154,922					9,622,306		9,622,306
7	Hartree Partners, LP	OS					1,395,042					83,184,892		83,184,892
8	Next Era Energy Power Marketing, LLC	OS					1,260,563					76,042,799		76,042,799
9	Shell Energy North America US, LP	OS					92,940					5,376,605		5,376,605
10	TransAlta Energy Marketing (U.S.) Inc.	OS					588,714					31,186,458		31,186,458
11	Vitol Inc.	OS					131,571					7,702,986		7,702,986
12	PECO Borderline	OS					157					8,277		8,277
13	Peak Energy Savings Credit	OS									591,785			591,785
14	Community Renewable Energy Facility	OS											1,355,551	1,355,551
15	AES Armenia Mountain Wind, LLC	IU					133,310					12,093,481		12,093,481
16	Chestnut Flats Wind, LLC	LU					94,077					8,346,493		8,346,493
17	Synergics Roth Rock Wind Energy, LLC	LU					96,691					8,679,652		8,679,652
18	Other RECs	OS										3,295,948		3,295,948
19	Altre, LLC	OS										61,200		61,200

20	AMERESCO	OS										170,088		170,088
21	Avangrid Renewables, LLC	OS										840,845		840,845
22	Juwi Inc.	OS										158,895		158,895
23	White Oaks Solar Energy LLC	OS										2,550,992		2,550,992
24	Delaware Sustainable Energy Utility	OS										5,585,445		5,585,445
25	Sol Systems LLC	OS										235,468		235,468
26	SREC Trade, Inc	OS										116,971	3,426	120,397
27	TerraForm Power LLC (Arcadia Solar, LLC)	OS										108,200		108,200
28	AMEREX Brokers LLC	OS											1,010	1,010
29	Walnut Ridge Wind, LLC (BHE Wind)	OS										3,287,500		3,287,500
30	ICAP Energy LLC	OS											3,876	3,876
31	Karbone Inc.	OS											21,000	21,000
32	TFS Energy Futures LLC	OS											16,374	16,374
15	TOTAL						7,613,907	0	0	0	3,282,569	483,203,938	85,164,442	571,650,949

FERC FORM NO. 1 (ED. 12-90)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
FOOTNOTE DATA			

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower Exelon Generation Company LLC and Delmarva Power and Light Company were both subsidiaries of Exelon Corporation as of February 1, 2022 and December 31, 2022, respectively. On February 2, 2022 the Exelon Generation Company spun off into its own company, Constellation Energy Resources, LLC.
(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower PECO Energy Company and Delmarva Power and Light Company were both subsidiaries of Exelon Corporation as of December 31, 2022.
(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 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.
(k) 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.
(l) 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.
(m) Concept: StatisticalClassificationCode Megawatt Hours which PECO customers consumed on PHI territory which was read by PHI but billed by PECO.

(n) Concept: StatisticalClassificationCode		
Peak energy savings credit program designed to reduce energy usage during times of peak energy demand.		
(o) Concept: StatisticalClassificationCode		
Customer bill credits associated with the Community Renewable Energy Facility program in Maryland.		
(p) Concept: StatisticalClassificationCode		
Megawatt Hours purchased from Armenia Mountain Wind, LLC under Renewable Wind Energy Power Purchase Agreement (PPA). Termination Date : 12/19/2024		
(q) Concept: StatisticalClassificationCode		
Megawatt Hours purchased from Chestnut Flats Wind, LLC under Renewable Wind Energy Power Purchase Agreement (PPA). Termination Date : 12/29/2031		
(r) Concept: StatisticalClassificationCode		
Megawatt Hours purchased from Roth Rock Wind Farm, LLC under Renewable Wind Energy Power Purchase Agreement (PPA). Termination Date : 08/03/2031		
(s) Concept: StatisticalClassificationCode		
Represents net accruals for renewable energy credits in Delaware and Maryland.		
(t) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(u) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(v) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(w) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(x) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(y) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(z) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(aa) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(ab) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(ac) Concept: StatisticalClassificationCode		
Represents retirement of renewable energy credits purchased on the open-market for Delaware.		
(ad) Concept: OtherChargesOfPurchasedPower		
PJM Interconnection, LLC		
Balancing Operating Reserve	\$	398,922
Balancing Operating Reserve for Load Response		(2)
Day-ahead Scheduling Reserve		4,352
Load Reconciliation for Balancing Operating Reserve		722
Load Reconciliation for Day-ahead Scheduling Reserve		136
Load Reconciliation for Non- Synchronized Reserve		373
Load Reconciliation for Reactive Services		109
Load Reconciliation for Regulation & Frequency Response Service		2,639
Load Reconciliation for Synchronized Reserve		2,631
Network Integration Transmission Service		83,046,215
Non- Synchronized Reserve		(6,929)
Reactive Services		6,535
Reactive Supply & Voltage Control		144,092
Regulation & Frequency Response Service		135,801
Secondary Reserve		334
Synchronized Reserve		27,894
PJM FERC Ordered Refund		(619)
	\$	83,763,205
(ae) Concept: OtherChargesOfPurchasedPower		
Customer bill credits associated with the Community Renewable Energy Facility program in Maryland.		
(af) Concept: OtherChargesOfPurchasedPower		
Represents broker fees on purchases of renewable energy credits.		
(ag) Concept: OtherChargesOfPurchasedPower		
Represents broker fees on purchases of renewable energy credits.		
(ah) Concept: OtherChargesOfPurchasedPower		
Represents broker fees on purchases of renewable energy credits.		
(ai) 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: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

- 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.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- 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).
- 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.
- 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.
- 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.
- 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.
- Report in column (i) and (j) the total megawatthours received and delivered.
- 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.
- 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.
- Footnote entries and provide explanations following all required data.

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)	TRANSFER OF ENERGY		REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS			
									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								2,881,471	2,881,471
2	PJM Trans Owner Sched, Sys Control												1,494,179	1,494,179
3	PJM Network Integration Transmission Svc												181,985,435	181,985,435
4	Other Transmission Agreements												4,347,285	4,347,285
5	PJM Transmission Enhancement Credits												1,829,411	1,829,411
6	AEP Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		119,519	0				
7	Alpha Gas and Electric, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,077	0				
8	Ambit Energy (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,903	0				
9	Ambit Energy (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		3,541	0				
10	American Power & Gas of MD, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,745	0				
11	Astral Energy LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		38	0				
12	Atlantic Energy MD, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,377	0				
13	Atlantic Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,838	0				
14	BOC Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		188,289	0				
15	Brookfield Renewable Energy Marketing US LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,701	0				
16	Calpine Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		216,006	0				
17	Champion Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		39,260	0				
18	CleanChoice Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL	DPL		43,739	0				

						SYSTEM	SYSTEM						
19	Clearview Electric (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	5,835	0				
20	Clearview Electric (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	4,065	0				
21	Commerce Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	40,995	0				
22	Constellation NewEnergy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	1,553,022	0				
23	Direct Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	672,996	0				
24	Discount Energy Group LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	303	0				
25	Discount Power, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	1,963	0				
26	EDF Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	138,161	0				
27	ELIGO	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	1,698	0				
28	Energy Harbor	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	8,399	0				
29	Energy Plus Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	2,953	0				
30	Engie Resources	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	264,284	0				
31	First Point Power, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	1,074	0				
32	Freepoint Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	109,901	0				
33	GEXA Energy Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	266,522	0				
34	GEXA Energy Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	14,177	0				
35	Great American Power, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	2,175	0				
36	Green Mountain Energy Company (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	727	0				
37	Greenlight Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	1,011	0				
38	Horizon Power & Light LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	4,099	0				
39	Hudson Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	4,092	0				
40	IDT Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	3,716	0				
41	Indra Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	11,262	0				
42	Inspire Energy Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	36,825	0				
43	Josco Energy USA LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	7	0				
44	Kuehne Chemical Co	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	72,530	0				
45	Liberty Power Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	76	0				
46	Major Energy Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	5,524	0				
47	Maryland Gas & Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	8,423	0				
48	MidAmerican Energy Services, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	123,697	0				
49	MP2 Energy NE LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM	33,378	0				

50	NextEra Energy Services Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,758	0				
51	NextEra Energy Services Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		276	0				
52	Nordic Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2	0				
53	Park Power, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,489	0				
54	PBF Power Marketing, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		360,374	0				
55	Plymouth Rock Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,086	0				
56	Public Power of MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		18,540	0				
57	Reliant Energy Northeast LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		141,661	0				
58	Residents Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,171	0				
59	RPA Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,451	0				
60	Rushmore Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		43,130	0				
61	SFE Energy Maryland, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		8,900	0				
62	SmartEnergy Holdings, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		24,749	0				
63	SmartEnergy Holdings, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,310	0				
64	SmartestEnergy US LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,459	0				
65	Spark Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,612	0				
66	Star Energy Partners, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		267	0				
67	Starion Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2	0				
68	StateWise Energy Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		443	0				
69	Stream Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		3,969	0				
70	Stream Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,852	0				
71	SunSea	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		292	0				
72	Talen Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		226,153	0				
73	Texas Retail Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		29,037	0				
74	Titan Gas, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		11,581	0				
75	Tomorrow Energy Corp	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,002	0				
76	UGI Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		46,521	0				
77	Viridian Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		3,851	0				
78	Washington Gas Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		574,756					
79	XOOM Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		8,047					
80	XOOM Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS	PJM Tariff	DPL SYSTEM	DPL SYSTEM		13,274					
35	TOTAL								5,595,938				192,537,781	192,537,781

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ 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) and PECO Energy for EHV/TEF (Extra High Voltage/Transmission Enhancement Facilities) agreements.
(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: 12/31/2022	Year/Period of Report End of: 2022/ 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					

2									
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
	TOTAL		0	0	0	0	0	0	0

FERC FORM NO. 1 (REV. 02-04)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	424,716
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	116,289
7	Board of Director Expenses	76,155
8	Research, Development and Demonstration, including Memberships	35,734
9	DE Environmental & Low Income and MD Universal Fund	6,310,247
10	Credit card accruals	23,873
11	Miscellaneous	
46	TOTAL	6,987,014

FERC FORM NO. 1 (ED. 12-94)

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

- 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).
- 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.
- 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.
- 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			9,187,922		9,187,922
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	54,143,783				54,143,783
8	Distribution Plant	84,911,410				84,911,410
9	Regional Transmission and Market Operation					
10	General Plant	13,209,263				13,209,263
11	Common Plant-Electric	5,629,722		11,166,521		16,796,243
12	TOTAL	157,894,178		20,354,443		178,248,621

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	85,602	70 years	(20)	1.66	R2	
15	353	681,291	42 years	(25)	3.52	S0.5	
16	354	73,958	75 years	(45)	1.39	R3	
17	355	596,841	43 years	(75)	4.27	R2.5	
18	356	325,323	55 years	(75)	3.47	R2	
19	357	6,076	60 years		1.26	R4	
20	358	62,697	55 years	(10)	1.9	R3	
21	359	1,111	65 years		0.54	R4	
22	SUBTOTAL	1,866,558					
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	27,871	65 years	(10)	1.27	R4	
27	361 MD	29,508	60 years	(15)	1.78	R1.5	
28	362 DE	266,619	45 years	(20)	2.08	R2	
29	362 MD	218,879	45 years	(25)	2.59	R1.5	
30	364 DE	127,062	55 years	(100)	2.25	R2	
31	364 MD	135,369	55 years	(125)	2.94	R2	
32	365 DE	221,614	55 years	(100)	1.53	R1.5	
33	365 MD	251,709	57 years	(100)	2.23	R0.5	
34	366 DE	24,814	70 years	(5)	0.84	S3	
35	366 MD	1,087	55 years		1.25	R3	
36	367 DE	254,469	52 years	(40)	1.82	R3	
37	367 MD	200,181	48 years	(20)	2.29	R3	
38	368 DE	349,451	45 years	(50)	1.77	R2	

39	368 MD	299,013	36 years	(50)	3.61	R1	
40	369.1 DE	19,560	65 years	(120)	0.81	R4	
41	369.1 MD	8,889	65 years	(75)	2.73	R4	
42	369.2 DE	106,572	55 years	(60)	1.36	S3	
43	369.2 MD	92,805	50 years	(25)	1.88	R4	
44	370 DE	14,667	25 years	(3)	2.77	L0.5	
45	370 MD	6,980	30 years		2.19	R1	
46	370.1 DE	71,109	15 years	(3)	8.13	S2	
47	370.1 MD	43,540	10 years		14.64	S3	
48	371.2 DE	30,113	18 years	(40)	8.2	R2	
49	371.2 MD	11,286	45 years	(50)	2.73	R3	
50	373 DE	67,197	38 years	(30)	0.95	R2	
51	373 MD	16,053	30 years	(30)	5.1	L0.5	
52	SUBTOTAL	2,904,087					
53	GENERAL						
54	390 DE	12,685	50 years	(10)	1.01	R3	
55	390 MD	41,247	35 years	(10)	3.43	S0	
56	391.1 DE	2,927	19 years		5.65	L2	
57	391.1 MD	1,879	15 years		5.78	SQ	
58	391.3 MD	2,752	10 years		10.14	SQ	
59	391.3 DE	8,036	5 years		21.49	SQ	
60	393 DE	316	40 years		19.74	R4	
61	394 DE	10,860	25 years		6.56	SQ	
62	394 MD	11,412	15 years		7.19	SQ	
63	395 DE		20 years		15.46	SQ	
64	397 MD	31,376	30 years	(10)	3.32	S2.5	
65	397 DE	71,794	25 years		4.13	L3	
66	397.1 MD	17,877	15 years		7.9	R2	
67	397.1 DE	18,066	15 years		6.98	S2	
68	397.3 MD	59,081	15 years		8.44	SQ	
69	397.3 DE	2,780	15 years		6.98	SQ	
70	398.1 DE	2,042	20 years		5.74	SQ	
71	398.1 MD	2,982	15 years		8.16	SQ	
72	392.2 DE	658	10 years		8.4	S2.5	
73	392.8 DE	196	20 years		4.57	S0	
74	392.3 MD	412	14 years		6.8	S1.5	
75	392.4 MD		15 years		6.1	R2.5	
76	SUBTOTAL	299,378					
77	COMMON						
78	390.3	56,448	75 years	(5)	0.8	S1.5	
79	390.3a	12,208	75 years	(5)	0.73	S1.5	
80	390.3b	781	40 years	(20)	(0.09)	R2	
81	391.1	5,600	20 years		5.38	SQ	
82	391.2	15,573	5 years		36.45	SQ	
83	393		25 years		6.27	SQ	
84	394	5,222	25 years		6.56	SQ	
85	397.1a	4,708	25 years		4.13	L3	

86	397.3	19,721	15 years		0.09	SQ	
87	398	11,518	20 years		5.22	SQ	
88	SUBTOTAL	131,779					
89	total	5,201,802					

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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.

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 (d)	Deferred in Account 182.3 at Beginning of Year (e)	EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR			
						CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
						Department (f)	Account No. (g)	Amount (h)				
1	Delaware											
2	2020 DE Rate Case 20-0149		259,893	259,893		Electric	928	259,893				
3	2022 DE Rate Case 22-0897		163,059	163,059		Electric	928	163,059				
4	DE Electric DSIC		9,742	9,742		Electric	928	9,742				
5	General Regulation Legal		102,467	102,467		Electric	928	102,467				
6	Maryland											
7	2017 MD Base Rate Case 9455		2,408	2,408		Electric	928	2,408				
8	2019 MD Base Rate Case 9630		44,039	44,039		Electric	928			928	44,039	
9	2021 MD Base Rate Case 9670		161,441	161,441		Electric	928	125,716		928	35,725	
10	2022 MD MYP 9681		807,201	807,201		Electric	928	807,201				
11	PC44 DPL MD		28,738	28,738		Electric	928	28,738				
12	General Regulation Legal		210,864	210,864		Electric	928	210,864				
13	Transmission:											
14	ER05-515 Annual Rate Updates - FERC Transmission		239,997	239,997		Electric	928	239,997				
15	ER21-2965 - Transmission Wages and Salary (W&S) Allocator		62,050	62,050		Electric	928	62,050				
16	ER22-2201 Transmission Depreciation Rates		3,358	3,358		Electric	928	3,358				
46	TOTAL		2,095,257	2,095,257				2,015,493			79,764	

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	A-2 and A-3	Other - 3 Projects (less than \$50K)	20,861		Various	20,861	
2	B-1	Membership - EPRI		290,727	Various	290,727	
3	B-4	Membership - CU Boulder College of Engineering (CU Foundation)		941	Various	941	
4	B-4	Membership - NEETRAC (Georgia Tech Research Corp)		10,674	Various	10,674	
5	B-4	Membership - Electric Drive Transportation Association		10,865	930.2	10,865	
6	B-4	Membership - Darcy Partners Power & Utilities		18,330	Various	18,330	
7	Total		20,861	331,537		352,398	

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
FOOTNOTE DATA			

(a) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts			
Other - 5 Projects (less than \$50K):			
FERC	Amount		
930.2	\$	15,703	
588		2,579	
566		2,579	
Total	\$	20,861	
(b) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts			
Membership - EPRI:			
FERC	Amount		
588	\$	154,085	
566		136,642	
Total	\$	290,727	
(c) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts			
Membership - CU Boulder College of Engineering (CU Foundation):			

FERC		Amount	
588	\$		470
566			471
Total	\$		941

(d) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Membership - NEETRAC (Georgia Tech Research Corp):

FERC		Amount	
588	\$	5,444	
566		5,230	
Total	\$	10,674	

(e) Concept: AccountNumberForResearchDevelopmentAndDemonstrationCosts

Membership - Darcy Partners Power & Utilities:

FERC		Amount	
930.2	\$	9,165	
588		9,165	
Total	\$	18,330	

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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			
4	Transmission	686,434		
5	Regional Market			
6	Distribution	12,305,522		
7	Customer Accounts	984,959		
8	Customer Service and Informational	1,771,025		
9	Sales			
10	Administrative and General	2,766,141		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	18,514,081		
12	Maintenance			
13	Production			
14	Transmission	3,556,837		
15	Regional Market			
16	Distribution	17,125,992		
17	Administrative and General	36,539		
18	TOTAL Maintenance (Total of lines 13 thru 17)	20,719,368		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)			
21	Transmission (Enter Total of lines 4 and 14)	4,243,271		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	29,431,514		
24	Customer Accounts (Transcribe from line 7)	984,959		
25	Customer Service and Informational (Transcribe from line 8)	1,771,025		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	2,802,680		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	39,233,449	2,084,219	41,317,668

29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply	505,910		
34	Storage, LNG Terminating and Processing	759,751		
35	Transmission	1,095,362		
36	Distribution	6,924,133		
37	Customer Accounts	346,415		
38	Customer Service and Informational	123,731		
39	Sales			
40	Administrative and General	924,630		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	10,679,932		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminating and Processing	76,491		
47	Transmission	231,030		
48	Distribution	1,830,238		
49	Administrative and General	5,248		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	2,143,007		
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)	505,910		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	836,242		
56	Transmission (Lines 35 and 47)	1,326,392		
57	Distribution (Lines 36 and 48)	8,754,371		
58	Customer Accounts (Line 37)	346,415		
59	Customer Service and Informational (Line 38)	123,731		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	929,878		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	12,822,939	398,993	13,221,932
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	52,056,388	2,483,212	54,539,600
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	50,966,568	3,059,016	54,025,584
69	Gas Plant	7,258,696	341,149	7,599,845
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	58,225,264	3,400,165	61,625,429
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,867,598	386,553	5,254,151

74	Gas Plant	321,752	18,869	340,621
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,189,350	405,422	5,594,772
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Expenses from Merchandising, Jobbing & Contract Work - 416	(56,314)	1,664	(54,650)
80	Expenses of Non-Utility Operations - 417.1	15,621	1,062	16,683
81	Donations - 426.1	20,775	1,203	21,978
82	Exp. For Certain Civic, Political & Related Activities - 426.4	22,575	940	23,515
83	Other Deductions - 426.5	552,907	792	553,699
84	Plant Held for Future -105	4,192		4,192
85	Other Deferred Credits-253	65,694		65,694
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	625,450	5,661	631,111
96	TOTAL SALARIES AND WAGES	116,096,452	6,294,460	122,390,912

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ 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 \$3,398,138 for full-year 2022. PHI Service Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 21 of this schedule total \$994,119 for full-year 2022.
(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 \$6,809,238 for full-year 2022. PHI Service Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 27 of this schedule total \$10,811,631 for full-year 2022.
(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 \$11,899,303 for full-year 2022. PHI Service Company salaries and wages included in DPL operations and maintenance expense but not reflected on line 28 of this schedule total \$28,335,109 for full-year 2022.

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
COMMON UTILITY PLANT AND EXPENSES			
<p>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.</p> <p>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.</p>			

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	52,470,032	18,941,504	—	—	71,411,536
389.1	1,621,110	—	—	—	1,621,110
390.3	69,519,523	1,824,950	(1,857,678)	—	69,485,795
391.1	5,206,517	393,089	—	—	5,599,606
391.3	10,733,206	4,923,505	(86,181)	—	15,570,530
393	—	—	—	—	—
394	4,714,954	506,601	—	—	5,221,555
397	24,737,724	920,938	—	(487,205)	25,171,457
398	10,541,943	241,055	—	—	10,782,998
Grand Total	\$ 180,280,509	\$ 27,751,642	\$ (1,943,859)	\$ (487,205)	\$ 205,601,087

Acct	Total Common			E = 82.62%	G = 17.38%
	Electric	Gas	Utility Plant		
301	\$ 608,496	\$ 128,004	\$ 736,500		
303	59,000,211	12,411,325	71,411,536		
389.1	1,339,361	281,749	1,621,110		
390.3	57,409,164	12,076,631	69,485,795		
391.1	4,626,394	973,212	5,599,606		
391.3	12,864,372	2,706,158	15,570,530		
393	—	—	—		
394	4,314,049	907,506	5,221,555		
397	20,796,658	4,374,799	25,171,457		
398	8,908,913	1,874,085	10,782,998		
	\$ 169,867,618	\$ 35,733,469	\$ 205,601,087		

Accumulated Provision for Depreciation of Common Utility Plant

DPL
12/31/2022

	Total Common	Electric	Gas
Balance at Beginning of Year	77,206,291	63,394,086	13,812,205
Depreciation Provision for the Year Charged to:			
403 Depreciation Expense	6,739,937	5,629,722	1,110,215
Net Charges for Plant Retired:			
Book Charges for Plant Retired	(1,943,859)	(1,606,016)	(337,843)
Cost of Removal, Net of Salvage	410,196	338,904	71,292
Other Debit or Credit Items:			
Transfers / Adjustments	(289,452)	(239,146)	(50,306)
Gain from Sale	—	—	—
Electric & Gas Allocator Adjustment	—	332,565	(332,565)
Balance at End of Year	82,123,113	67,850,115	14,272,998

Accumulated Provision for Amortization of Common Utility Plant

DPL
12/31/2022

	Total Common	Electric	Gas
Balance at Beginning of Year	24,552,556	20,160,103	4,392,453
Depreciation Provision for the Year Charged to:			
404 Amortization Expense	13,715,844	11,166,521	2,549,323
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	—	290,729	(290,729)
Balance at End of Year	38,268,400	31,617,353	6,651,047

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ 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)	1,606,104	8,171,189	23,372,427	32,631,840
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(5,528,319)	(11,943,909)	(16,236,581)	(22,664,810)
4	Transmission Rights	18,860,636	39,104,533	61,189,779	83,046,215
5	Ancillary Services	16,912	175,262	478,747	797,499
6	Other Items (list separately)				
7	Demand	115,884	833,164	1,826,685	2,664,692
46	TOTAL	15,071,217	36,340,239	70,631,057	96,475,436

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

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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.

- On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
- 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.
- On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
- On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
- 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.
- 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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		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	7,613,907	MWH	217,696	13,209,845	MWH	1,494,179
2	Reactive Supply and Voltage		MWH	144,092			
3	Regulation and Frequency Response		MWH	138,440			
4	Energy Imbalance						
5	Operating Reserve - Spinning		MWH	30,525			
6	Operating Reserve - Supplement		MWH	17,398			
7	Other		MWH	458,350			
8	Total (Lines 1 thru 7)	7,613,907	MWH	1,006,501	13,209,845		1,494,179

FERC FORM NO. 1 (New 2-04)

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FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

The number of units reported on Line #2, Column (b) is 7,613,907 MWH.

(b) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

The number of units reported on Line #3, Column (b) is 7,613,907 MWH.

(c) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

The number of units reported on Line #5, Column (b) is 7,613,907 MWH.	
(d) Concept: AncillaryServicesPurchasedNumberOfUnitsPower	
The number of units reported on Line #7, Column (b) is 7,613,907 MWH.	
(e) Concept: AncillaryServicesPurchasedAmount	
Other Ancillary Services Purchased is as follows:	
Balancing Operating Reserve	\$ 453,774
Day-ahead Scheduling Reserve	4,488
Non-Synchronized Reserve	(6,556)
Reactive Services	6,644
	\$ 458,350

FERC FORM NO. 1 (New 2-04)

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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	3,538	27	8	2,628	910					
2	February	3,370	15	8	2,449	921					
3	March	2,992	12	21	2,205	787					
4	Total for Quarter 1				7,282	2,618	0	0	0	0	
5	April	2,355	11	8	1,669	686					
6	May	3,529	31	18	2,698	831					
7	June	3,619	17	18	2,785	834					
8	Total for Quarter 2				7,152	2,351	0	0	0	0	
9	July	3,867	21	16	2,970	897					
10	August	4,069	9	18	3,149	920					
11	September	3,214	1	18	2,434	780					
12	Total for Quarter 3				8,553	2,597	0	0	0	0	
13	October	2,188	19	8	1,578	610					
14	November	2,925	21	8	2,177	748					
15	December	3,599	24	8	2,873	726					
16	Total for Quarter 4				6,628	2,084	0	0	0	0	
17	Total				29,615	9,650	0	0	0	0	

FERC FORM NO. 1 (NEW. 07-04)

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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.

FERC FORM NO. 1 (NEW. 07-04)

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

FERC FORM NO. 1 (NEW. 07-04)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 2022-12-31	Year/Period of Report End of: 2022/ Q4
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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)	12,102,227
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	915
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	355,154
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	17,409
7	Other		27	Total Energy Losses	734,140
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	13,209,845
10	Purchases (other than for Energy Storage)	7,613,907			

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	5,595,938
17	Delivered	
18	Net Transmission for Other (Line 16 minus line 17)	5,595,938
19	Transmission By Others Losses	
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	13,209,845

FERC FORM NO. 1 (ED. 12-90)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	1,352,463	34,176	3,538	27	18
30	February	1,091,814	34,883	3,370	15	8
31	March	1,057,583	41,749	2,992	12	21
32	April	892,063	48,922	2,355	11	8
33	May	967,180	28,149	3,529	31	18
34	June	1,084,682	20,484	3,619	17	18
35	July	1,339,234	16,813	3,867	21	16
36	August	1,318,450	13,029	4,069	9	18
37	September	1,019,122	20,691	3,214	1	18
38	October	896,594	27,386	2,188	19	8
39	November	973,872	37,324	2,925	21	8
40	December	1,216,788	31,548	3,599	24	8
41	Total	13,209,845	355,154			

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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.

FERC FORM NO. 1 (ED. 12-90)

Page 401b

Name of Respondent:	This report is: (1) An Original	Date of Report:	Year/Period of Report
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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 Mct.
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	

FERC FORM NO. 1 (REV. 12-03)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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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	

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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 Demand 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

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)	Project Costs included in (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1																			
2																			
3																			
4																			
5																			
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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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TRANSMISSION LINE STATISTICS

- 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.
- 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.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- 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.
- 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.
- 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).
- 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.
- 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.
- 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)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)		(f)	(g)			(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	237,187,164	252,573,325				
3	138 KV Lines		138	138	Various	503.91	82.53	83		11,248,373	451,067,603	462,315,976				
4	69kV Lines		69	69	Various	568.48	13.02	73		7,548,675	270,341,868	277,890,543				
5	Underground Lines	5.38 mi /138, 2.09 mi/69				7.47		10		9,713	67,507,137	67,516,850				
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												8,332,779	4,428,190	202,833	12,963,802
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	11.54		1	1590							

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	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	1.36	2.87	1	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			1590 ACSR										
36	TOTAL					2,655.53	345.43	314		35,400,557.00	1,055,720,580.00	1,091,121,137.00	8,332,778.71	4,428,190.11	202,832.70	12,963,801.52			

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
FOOTNOTE DATA			

(a) Concept: LengthForStandAloneTransmissionLines

Includes 3.15 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 2.81 miles of UG as well.																								
(e) Concept: LengthForStandAloneTransmissionLines Includes 1.24 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: <table border="0" style="width: 100%; border-collapse: collapse;"> <tr> <td style="width: 80%;"></td> <td style="text-align: right; border-bottom: 1px solid black;">Percentage</td> </tr> <tr> <td>Public Service Electric & Gas</td> <td style="text-align: right;">42.55</td> </tr> <tr> <td>Atlantic City Electric</td> <td style="text-align: right;">13.90</td> </tr> <tr> <td>Delmarva Power & Light</td> <td style="text-align: right;">1.00</td> </tr> <tr> <td>PECO Energy Co</td> <td style="text-align: right;">42.55</td> </tr> <tr> <td>Total</td> <td style="text-align: right; border-top: 1px solid black;">100.00</td> </tr> </table> 2. Owners in common of the reconstructed river crossing portion of the Hope Creek-Red Lion line are as follows: <table border="0" style="width: 100%; border-collapse: collapse;"> <tr> <td style="width: 80%;"></td> <td style="text-align: right; border-bottom: 1px solid black;">Percentage</td> </tr> <tr> <td>Public Service Electric & Gas</td> <td style="text-align: right;">42.55</td> </tr> <tr> <td>Atlantic City Electric</td> <td style="text-align: right;">7.45</td> </tr> <tr> <td>Delmarva Power & Light</td> <td style="text-align: right;">7.45</td> </tr> <tr> <td>PECO Energy Co</td> <td style="text-align: right;">42.55</td> </tr> <tr> <td>Total</td> <td style="text-align: right; border-top: 1px solid black;">100.00</td> </tr> </table> 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).		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		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
	Percentage																							
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Atlantic City Electric	7.45																							
Delmarva Power & Light	7.45																							
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Total	100.00																							
(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) 1752, (G) 179, Column (H) 203.																								
(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) 1752, (G) 179, Column (H) 203.																								
(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) 1752, (G) 179, Column (H) 203.																								

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

Page 422-423

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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TRANSMISSION LINES ADDED DURING YEAR

- 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.
- Provide separate subheadings for overhead and under-ground construction and show each transmission line separately. If actual costs of completed 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).
- 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				LINE COST					Construction
	From	To	Type		Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing	Voltage KV (Operating)	Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total		

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	SOLADIGO SOLAR	TOWNSEND	0.07	0	0			795 ACSR			138		3,639	404		4,043	
44	TOTAL		0.07		0	0	0						3,639	404		4,043	

FERC FORM NO. 1 (REV. 12-03)

Page 424-425

Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- 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.
- 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).
- Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
- 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	20	1	0	0	0	0
5	Basin Road - New Castle, DE 3	Distribution	Unattended	138	12	0	22	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	1	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	0	0	0
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	Distribution	Unattended	69	12	0	75	2	0	0	0	0
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	48	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	1	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	0	0	0
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	222	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	0	0	0
70	Five Points - Five Points, DE	Distribution	Unattended	69	12	0	44	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	0	0	0
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	0	0	0
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	Distribution	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	0	0	0
103	Kenney - Snow Hill, MD 1	Distribution	Unattended	69	25	0	13	1	0	0	0	0
104	Kenney - Snow Hill, MD2	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	0	0	0
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	8	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	66	2	0	0	0	0
130	Milltown - Mill Cr Rd, DE	Distribution	Unattended	138	12	0	102	2	0	0	0	0
131	Montchanin - Wilmington, DE	Distribution	Unattended	35	15	0	8	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	0	0	0
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	0	0	0
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	Distribution	Unattended	69	12	0	123	3	0	0	0	0
139	Normira - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
140	North East - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
141	N Salisbury - Salisbury, MD	Distribution	Unattended	69	25	0	93	2	0	0	0	0
142	N Seaford - Seaford, DE 1	Transmission	Unattended	138	69	0	187	2	0	0	0	0
143	N Seaford - Seaford, DE 2	Distribution	Unattended	69	12	0	47	2	0	0	0	0
144	Oak Hall - Oak Hall, VA	Transmission	Unattended	138	69	0	224	2	0	0	0	0
145	Ocean Bay - Ocean City, MD 1	Distribution	Unattended	138	12	0	84	2	0	0	0	0
146	Ocean Bay - Ocean City, MD 2	Transmission	Unattended	138	69	0	224	1	0	0	0	0
147	Ocean City - Ocean City, MD 3	Distribution	Unattended	69	12	0	76	2	0	0	0	0
148	138th St - Ocean City, MD	Distribution	Unattended	138	12	0	84	2	0	0	0	0
149	Otsego - Cecil, MD	Distribution	Unattended	35	4	0	8	2	0	0	0	0
150	Pemberton - Salisbury, MD	Distribution	Unattended	69	25	0	37	1	0	0	0	0
151	Perch - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
152	Piney Grove - Salisbury, MD 1	Transmission	Unattended	138	69	0	225	1	0	0	0	0
153	Piney Grove - Salisbury, MD 2	Transmission	Unattended	230	138	0	336	1	0	0	0	0

154	Pocomoke - Pocomoke, MD	Distribution	Unattended	138	12	0	45	2	0	0	0	0
155	Point Breeze - Brandywine, DE	Distribution	Unattended	35	12	0	42	2	0	0	0	0
156	Porter's Bridge - Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
157	Preston-Preston	Distribution	Unattended	69	12	0	7	1	0	0	0	0
158	Price Sub - Price, MD	Distribution	Unattended	69	25	0	28	1	0	0	0	0
159	Prince-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
160	Railroad -Elkton, MD	Distribution	Unattended	35	4	0	6	1	0	0	0	0
161	Red Lion-New Castle, DE 1	Transmission	Unattended	500	230	0	1569	2	0	0	0	0
162	Red Lion-New Castle, DE 2	Distribution	Unattended	138	25	0	28	1	0	0	0	0
163	Red Lion Sub-Pencader Hd, DE	Transmission	Unattended	230	138	0	672	2	0	0	0	0
164	Rehoboth Sub-Rehoboth, DE 1	Transmission	Unattended	138	69	0	200	1	0	0	0	0
165	Rehoboth Sub-Rehoboth, DE 2	Distribution	Unattended	69	12	0	75	2	0	0	0	0
166	Reybold Sub-Red Lion Hd, DE 1	Transmission	Unattended	138	69	0	112	1	0	0	0	0
167	Reybold Sub-Red Lion Hd, DE 2	Distribution	Unattended	138	12	0	75	2	0	0	0	0
168	Rising Sun-Cecil, MD	Distribution	Unattended	35	4	0	7	2	0	0	0	0
169	Sharptown-Sharptown, MD	Distribution	Unattended	69	12	0	7	1	0	0	0	0
170	Silverbrook Sub, DE	Distribution	Unattended	138	35	0	184	2	0	0	0	0
171	Silverside Rd Sub-Brandywine Hd, DE 1	Distribution	Unattended	69	12	0	67	2	0	0	0	0
172	Silverside Rd Sub-Brandywine Hd, DE 2	Distribution	Unattended	69	35	0	56	1	0	0	0	0
173	S Harrington Sub-Harrington, DE	Transmission	Unattended	138	69	0	112	1	0	0	0	0
174	Steele-Denton, MD 1	Transmission	Unattended	230	138	0	856	3	0	0	0	0
175	Steele-Denton, MD 2	Distribution	Unattended	138	25	0	28	1	0	0	0	0
176	Stevensville, MD	Distribution	Unattended	69	25	0	98	2	0	0	0	0
177	Stockton-Stockton, MD	Distribution	Unattended	69	4	0	5	1	0	0	0	0
178	Sunset Lake Sub-Pencader Hd, DE	Distribution	Unattended	138	12	0	100	3	0	0	0	0
179	Sussex Sub-Georgetown, DE	Distribution	Unattended	69	12	0	48	2	0	0	0	0
180	Talleyville Sub-Brandywine Hd, DE	Distribution	Unattended	35	12	0	42	2	0	0	0	0
181	Talleyville, DE	Distribution	Unattended	138	12	0	56	1	0	0	0	0
182	Theodore-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
183	Todd-Hurlock, MD 1	Distribution	Unattended	69	25	0	56	2	0	0	0	0
184	Todd-Hurlock, MD 2	Distribution	Unattended	69	12	0	11	1	0	0	0	0
185	Townsend Sub-New Castle Hd, DE	Distribution	Unattended	138	25	0	56	1	0	0	0	0
186	Trappe-Trappe, MD	Distribution	Unattended	69	12	0	50	2	0	0	0	0
187	Triumph-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
188	Vienna-Vienna, MD 1	Transmission	Unattended	138	69	0	224	2	0	0	0	0
189	Vienna-Vienna, MD-Local	Distribution	Unattended	69	12	0	3	1	0	0	0	0
190	Vienna-Vienna, MD 2	Transmission	Unattended	230	138	0	448	1	0	0	0	0
191	Walnut-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
192	Wattsville-Wattsville, VA	Transmission	Unattended	138	69	0	225	1	0	0	0	0
193	West Sub-Christiana Hd, DE 1	Distribution	Unattended	69	35	0	112	2	0	0	0	0
194	West Sub-Christiana Hd, DE 2	Distribution	Unattended	69	12	0	112	2	0	0	0	0
195	West Cambridge, MD	Distribution	Unattended	69	12	0	22	1	0	0	0	0
196	West Wilmington-Wilm, DE	Distribution	Unattended	138	12	0	168	2	0	0	0	0
197	Whiteford-Harford, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
198	Woodlawn-Cecil, MD	Distribution	Unattended	35	4	0	4	1	0	0	0	0
199	Worcester-Berlin, MD 1	Distribution	Unattended	69	25	0	66	2	0	0	0	0

200	Worcester-Berlin, MD 2	Transmission	Unattended	138	69	0	224	1	0	0	0	0
201	Wye Mills, Wye Mills, MD 1	Transmission	Unattended	138	69	0	450	2	0	0	0	0
202	Wye Mills, Wye Mills, MD 2	Distribution	Unattended	69	25	0	56	2	0	0	0	0
203	Wyoming, Wyoming, DE	Distribution	Unattended	25	12	0	3	1	0	0	0	0
204	Spare Transformer 1	Transmission	Unattended	500	230	0	336	0	2	0	0	0
205	Spare Transformer 2	Transmission	Unattended	230	69	0	336	0	3	0	0	0
206	Spare Transformer 3	Transmission	Unattended	138	69	0	336	0	1	0	0	0
207	Spare Transformer 4	Transmission	Unattended	138	12	0	225	0	1	0	0	0
208	Spare Transformer 5	Transmission	Unattended	138	69	0	40	0	1	0	0	0
209	Spare Transformer 6	Transmission	Unattended	69	12	0	225	0	2	0	0	0
210	Spare Transformer 7	Transmission	Unattended	69	12	0	56	0	3	0	0	0
211	Spare Transformer 8	Transmission	Unattended	69	25	0	40	0	3	0	0	0
212	Spare Transformer 9	Transmission	Unattended	69	13	0	75	0	1	0	0	0
213	Spare Transformer 10	Transmission	Unattended	138	25	0	75	0	4	0	0	0
214	Spare Transformer 11	Distribution	Unattended	230	138	0	28	0	1	0	0	0
215	Spare Transformer 12	Distribution	Unattended	230	16	0	336	0	2	0	0	0
216	Spare Transformer 13	Distribution	Unattended	69	25	0	150	0	1	0	0	0
217	Spare Transformer 14	Distribution	Unattended	138	16	0	56	0	2	0	0	0
218	Spare Transformer 15	Distribution	Unattended	69	12	0	150	0	2	0	0	0
219	Spare Transformer 16	Distribution	Unattended	230	69	0	38	0	5	0	0	0
220	Spare Transformer 17	Distribution	Unattended	138	69	0	336	0	1	0	0	0
221	Spare Transformer 18	Distribution	Unattended	138	25	0	225	0	1	0	0	0
222	Spare Transformer 19	Distribution	Unattended	138	12	0	38	0	1	0	0	0
223	Spare Transformer 20	Distribution	Unattended	69	35	0	38	0	1	0	0	0
224	Spare Transformer 21	Distribution	Unattended	138	25	0	56	0	1	0	0	0
225	Spare Transformer 22	Distribution	Unattended	34	4	0	56	0	0	0	0	0
226	Spare Transformer 23	Distribution	Unattended	69	12	0	4	0	1	0	0	0
227	Spare Transformer 24	Distribution	Unattended	34	4	0	56	0	0	0	0	0
228	Spare Transformer 25	Distribution	Unattended	138	12	0	2	0	0	0	0	0
229	Spare Transformer 26	Distribution	Unattended	34	12	0	56	0	1	0	0	0
230	Spare Transformer 27	Distribution	Unattended	138	36	0	20	0	1	0	0	0
231	Spare Transformer 28	Distribution	Unattended	34	4	0	84	0	0	0	0	0
232	Spare Transformer 29	Distribution	Unattended	500	230	0	243	0	0	0	0	0
233	Spare transformer 30	Distribution	Unattended	500	230	0	333	0	0	0	0	0
234	Spare Transformer 31	Distribution	Unattended	230	138	0	336	0	1	0	0	0
235	Spare Transformer 32	Distribution	Unattended	230	138	0	448	0	1	0	0	0
236	Spare Transformer 34	Distribution	Unattended	230	35	0	112	0	1	0	0	0
237	Spare Transformer 35	Distribution	Unattended	138	69	0	112	0	1	0	0	0
238	Spare Transformer 36	Distribution	Unattended	35	4	0	4	0	1	0	0	0
239	Spare Transformer 37	Distribution	Unattended	138	12	0	84	0	1	0	0	0
240	Spare Transformer 38	Distribution	Unattended	138	12	0	56	0	1	0	0	0
241	Spare Transformer 39	Distribution	Unattended	35	4	0	4	0	1	0	0	0
242	Spare Transformer 40	Distribution	Unattended	138	36	0	84	0	1	0	0	0
243	Spare Transformer 41	Distribution	Unattended	34	12	0	22	0	1	0	0	0
244	Spare Transformer 42		Unattended	0	0	0	0	0	1	0	0	0
245	Spare Transformer 43	Distribution	Unattended	138	25	0	0	0	1	0	0	0
246	Spare Transformer 44	Distribution	Unattended	69	12	0	20	0	1	0	0	0

247	Spare Transformer 45	Distribution	Unattended	69	25	0	28	0	1	0	0	0
248	Spare Transformer 46	Distribution	Unattended	25	12	0	3	0	1	0	0	0
249	TOTAL Transmission Substations			8,222	4,009	0	14877	53	21	0	2	69
250	TOTAL Distribution Substations			18,386	4,185	0	13687	261	35	0	26	281
251	TOTAL Generation Substations			0	0	0	0	0	0	0	0	0
252	TOTAL			26,608	8,194	0	28564	314	56	0	28	350

FERC FORM NO. 1 (ED. 12-96)

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Name of Respondent: Delmarva Power & Light Company	This report is: (1) An Original (2) A Resubmission	Date of Report: 12/31/2022	Year/Period of Report End of: 2022/ Q4
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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

- Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
- 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".
- 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	PHI Service Company (PHISCO)			
3	Centralized Support Services	PHISCO	Various	\$120,812,870
4	Exelon Business Services Company (EBSC)			
5	Centralized Support Services	EBSC	Various	\$115,898,296
6	Atlantic City Electric Co (ACE)			
7	Materials	ACE	Various	\$995,658
8	Facility Services	ACE	184	6,750
9	Mutual Assistance	ACE	593	3,799
10	Potomac Electric Power Company (Pepco)			
11	Materials	Pepco	Various	\$492,888
12	Atlantic Southern Properties (ASP)			
13	Facility Services	ASP	184	1,117
14	PECO Energy Company (PECO)			
15	Extra-High Voltage (EHV) Transmission Agreement charges	PECO	571	36,492
16	Information Technology Services	PECO	Various	\$5,674
17	Transmission System Operations Services	PECO	560	352
18	Baltimore Gas & Electric Co. (BGE)			
19	Transmission System Operations Services	BGE	560	1,027
20	Regulatory Services	BGE	928	6,643
21	Information Technology Services	BGE	Various	\$55,488
22	Drone Training Services	BGE	588	4,915
23	Materials	BGE	Various	\$378
24	Other Services	BGE	921	(10,332)
25	Commonwealth Edison Company (ComEd)			
26	Information Technology Services	ComEd	Various	\$44,946
27	Materials	ComEd	Various	\$249,409
28	Transmission System Operations Services	ComEd	560	209,518
29	Legal Services	ComEd	921	20,357

30	Constellation Power Source Gen (CPSG)			
31	Mechanical and Electrical Industrial Services	CPSG	Various	84,078
32	Exelon Clearsight, LLC (EC)			
33	Inspection Services	EC	583	84,269
34	Materials	EC	Various	33,573
35	Exelon PowerLabs, LLC (EPL)			
36	Calibration and Engineering Services	EPL	807.1	2,407
19				
20	Non-power Goods or Services Provided for Affiliated			
21	Atlantic City Electric Co (ACE)			
22	Materials	ACE	154/163/232	1,450,878
23	Extra-High Voltage (EHV) Transmission Agreement charges	ACE	456.1	78,288
24	Mutual Assistance	ACE	456	9,635
25	Facility Services	ACE	Various	18,157
26	Baltimore Gas & Electric Co. (BGE)			
27	Extra-High Voltage (EHV) Transmission Agreement charges	BGE	456	234,864
28	Communications Hardware Transfer	BGE	Various	65,164
29	Materials	BGE	154/163	6,725
30	Commonwealth Edison Company (ComEd)			
31	Expense Reimbursement	ComEd	456	2,361
32	Materials	ComEd	154/163	569
33	Potomac Electric Power Company (PEPCO)			
34	Mutual Assistance	PEPCO	456	40,164
35	Materials	PEPCO	154/163/232	900,631
36	Extra-High Voltage (EHV) Transmission Agreement charges	PEPCO	456.1	234,864
37	Facility Services	PEPCO	Various	8,324
38	PECO Energy Company (PECO)			
39	Extra-High Voltage (EHV) Transmission Agreement charges	PECO	456.1	287,052
40	Materials	PECO	154 / 163	360
41	Exelon Business Services Company (EBSC)			
42	Facility Services	EBSC	Various	538,791
43	Vehicle Services	EBSC	456	36,064
44	Materials	EBSC	154/163	24,975
45	PHI Service Company (PHISCO)			
46	Facility Services	PHISCO	Various	3,045,047
47	Vehicle Services	PHISCO	456	771,311
48	Materials	PHISCO	154/163/232	7,727
49	Constellation New Energy			
50	Consolidated Billing Coordination Fees	CNE	456	531
42				

Name of Respondent: Delmarva Power & Light Company	This report is:	Date of Report:	Year/Period of Report:
	(1) An Original (2) A Resubmission	12/31/2022	End of: 2022/ 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 and transmission 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: DescriptionOfNonPowerGoodOrService

As a result of the separation that occurred on February 1, 2022 between Exelon and one of its previous principal subsidiaries, Exelon Generation (including Generation's subsidiaries), the transactions for these affiliates included on this page precede the separation date.

(d) Concept: DescriptionOfNonPowerGoodOrService

As a result of the separation that occurred on February 1, 2022 between Exelon and one of its previous principal subsidiaries, Exelon Generation (including Generation's subsidiaries), the transactions for these affiliates included on this page precede the separation date.

(e) Concept: DescriptionOfNonPowerGoodOrService

As a result of the separation that occurred on February 1, 2022 between Exelon and one of its previous principal subsidiaries, Exelon Generation (including Generation's subsidiaries), the transactions for these affiliates included on this page precede the separation date.

(f) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

PHISCO Centralized Support Services to DPL:

FERC Account	Amount	FERC Account	Amount	FERC Account	Amount
107	\$ 21,056,267	573	7,848	893	345,956
108	2,705,816	580	137,627	902	124,825
163	581,356	581	11,246	903	37,729,827
182.3	350,048	582	5	908	2,203,244
184	1,491,693	583	863	909	15,931
254	35,438	584	8,993	923	39,729,921
416	62,536	585	(21)	924	16,185
417.1	453	586	956,342	925	181
419	(111,500)	587	412,864	928	1,780,559
426.1	161,667	588	3,362,244	930.1	351,524
426.3	4	589	488	930.2	190,141
426.4	121,387	590	12	935	11
426.5	1,158,264	591	1,265	Total	\$ 120,812,870
430	18,199	592	67,461		
431	(4,918)	593	926,761		
557	707,605	594	14,314		
560	1,172,400	595	1,923		
561.2	12,665	596	4,277		
566	1,015,952	597	264,806		
568	155	598	25,134		
569	11,199	813	248,576		
570	192,781	878	671,951		
571	460,082	892	37		

(g) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

EBSC Centralized Support Services to DPL:

FERC Account	Amount	FERC Account	Amount	FERC Account	Amount
107	\$ 43,142,596	592	120,268	879	3,629
108	774,439	593	789,576	880	1,398,339
163	968,192	594	122,261	881	45
182.3	151	595	15,581	885	11,425
184	789,645	596	23,364	887	37,824
416	36,908	597	11,750	889	3,196
417.1	1,277	598	20,607	892	49,226
426.1	394,808	807	9,008	893	7,999
426.3	35	813	29,348	894	33,125
426.4	36,805	840	924	902	74,673
426.5	3,485,236	841	58,979	903	11,217,768
560	5,971,646	843.1	478	904	35
561.2	22,885	843.4	241	908	430,405
566	606,918	843.5	506	921	261,898
569	2,085	843.6	1,300	923	40,153,066
570	253,346	843.7	209	924	796,540
571	5,087	843.9	3,419	925	1,103
573	14,285	850	1,435	926	49
580	20,611	851	63,491	928	8,104
581	147,914	856	14,140	930.1	174,628
582	(2)	857	3,893	930.2	65,381
583	19,008	859	2,513	935	4,411
584	32,768	860	837	Total	\$ 115,898,296
585	(16)	863	16,367		
586	364,444	865	91		
587	3,000	870	51,379		
588	2,335,011	871	19,077		
589	2,376	874	270,307		
590	86	875	10,444		
591	7,344	878	64,746		

(h) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

ACE Materials provided to DPL:

FERC Account	Amount
107	\$ 53,442
108	5,115
154	933,760
163	2,430
571	911
Total	<u>\$ 995,658</u>

(j) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Peppo Materials provided to DPL:

FERC Account	Amount
107	\$ 115,066
108	22,580
154	354,826
571	330
583	51
594	35
Total	<u>\$ 492,888</u>

(j) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

PECO Information Technology Services provided to DPL:

FERC Account	Amount
107	\$ 5,096
921	578
Total	<u>\$ 5,674</u>

(k) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

BGE Information Technology Services provided to DPL:

FERC Account	Amount
107	\$ 9,025
921	46,463
Total	<u>\$ 55,488</u>

(l) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

BGE Materials provided to DPL:

FERC Account	Amount
107	\$ 276
108	91
593	11
Total	<u>\$ 378</u>

(m) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

ComEd Information Technology Services provided to DPL:

FERC Account	Amount
107	\$ 43,274
921	1,672
Total	<u>\$ 44,946</u>

(n) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

ComEd Materials provided to DPL:

FERC Account	Amount
107	\$ 8,319
108	1,486
154	234,553
596	5,051
Total	<u>\$ 249,409</u>

(o) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

CPSG Mechanical and Electrical Industrial Services provided to DPL:

FERC Account	Amount
107	\$ 78,033
108	6,045
Total	<u>\$ 84,078</u>

(p) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

EC Materials provided to DPL:

FERC Account	Amount
107	\$ 25,484
108	7,252
593	837
Total	<u>\$ 33,573</u>

(q) Concept: DescriptionOfNonPowerGoodOrService

As a result of the separation that occurred on February 1, 2022 between Exelon and one of its previous principal subsidiaries, Exelon Generation (including Generation's subsidiaries), the transactions for these affiliates included on this page precede the separation date.

(r) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies

DPL Facility Services provided to ACE:

FERC Account	Amount
456	\$ 16,108
495	2,049

Total	\$	18,157
(s) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies		
DPL Communications Hardware Transfer provided to BGE:		
FERC Account		Amount
101	\$	76,093
108		(10,929)
Total	\$	65,164
(t) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies		
DPL Facility Services provided to Pepco:		
FERC Account		Amount
456	\$	7,403
495		921
Total	\$	8,324
(u) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies		
DPL Facility Services provided to EBSC:		
FERC Account		Amount
456	\$	458,888
495		79,903
Total	\$	538,791
(v) Concept: DueFromOrCreditedByTheTransactionsWithAssociatedAffiliatedCompanies		
DPL Facility Services provided to PHISCO:		
FERC Account		Amount
456	\$	2,593,466
495		451,581
Total	\$	3,045,047

FERC FORM NO. 1 ((NEW))

Name of Respondent DPL - Maryland	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of 2022/Q4
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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	336,452,808	315,401,242
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	143,041,785	116,275,800
5	Large (or Ind.) (See Instr. 4)	11,416,443	9,932,115
6	(444) Public Street and Highway Lighting	4,271,876	3,985,092
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	495,182,912	445,594,249
11	(447) Sales for Resale	1,054,205	(38,652)
12	TOTAL Sales of Electricity	496,237,117	445,555,597
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. For Refunds	496,237,117	445,555,597
15	Other Operating Revenues		
16	(450) Forfeited Discounts	939,726	685,399
17	(451) Miscellaneous Service Revenues	95,499	154,216
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,580,488	1,563,058
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	554,488	4,120,513
22	(456.1) Revenues from Transmission of Electricity of Others	693,621	647,420
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	3,863,822	7,170,606
27	TOTAL Electric Operating Revenues	500,100,939	452,726,203

Name of Respondent DPL - Maryland	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of 2022/Q4
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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)	MEGAWATT HOURS SOLD		AVG. NO. CUSTOMERS PER MONTH	
		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	2,203,909	2,199,710	183,381	181,926
3	(442) Commercial and Industrial Sales				
4	Small (or Comm.) (See Instr. 4)	1,658,376	1,599,842	27,876	27,613
5	Large (or Ind.) (See Instr. 4)	349,101	345,307	152	162
6	(444) Public Street and Highway Lighting	10,891	10,813	258	260
7	(445) Other Sales to Public Authorities				
8	(446) Sales to Railroads and Railways				
9	(448) Interdepartmental Sales				
10	TOTAL Sales to Ultimate Consumers	4,222,277	4,155,672	211,667	209,961
11	(447) Sales for Resale	20,992	(807)		
12	TOTAL Sales of Electricity	4,243,269	4,154,865	211,667	209,961
13	(Less) (449.1) Provision for Rate Refunds				
14	TOTAL Revenues Net of Prov. For Refunds	4,243,269	4,154,865	211,667	209,961

Line 12, column (b) includes \$5,623,123 of unbilled revenues in 2022

Line 12, column (d) includes 23,016 MWH relating to unbilled revenues in 2022

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FOOTNOTE DATA

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

Items greater than \$250,000:

\$ 532,779 RPM Auction
(466,679) MD Bill Stabilization Adjustment
(2,445,539) MD Calendar Revenue Normalization
451,319 RPM Seasonal Capacity Performance Auction
856,050 MD Intracompany Power Sales
1,343,906 Price Responsive Demand Credit

Name of Respondent DPL - Maryland	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of 2022/Q4
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Schedule Page: 300 Line No.: 21 Column: c

Items greater than \$250,000:

\$ 1,341,558 RPM Auction
(2,513,896) MD Bill Stabilization Adjustment
1,374,606 MD Calendar Revenue Normalization
618,619 MD Intracompany Power Sales
996,996 Net Metering
2,104,571 Price Responsive Demand Credit

DELMARVA POWER & LIGHT COMPANY
MARYLAND PROPERTY TAXES PAID
12/31/2022

Location	Rounded 2022 Taxes Paid
Caroline County	1,082,877
Cecil County	4,419,177
City of Cambridge	220,176
City of Crisfield	54,095
City of Fruitland	-
City of Salisbury	1,997,645
Delmar	30,866
Dorchester County	3,266,312
Eldorado	-
Galena	2,917
Harford County	525,746
Hebron	10,624
Hillsboro	-
Hurlock	-
Kent County	2,090,204
Mardela Springs	-
Pocomoke City	148,727
Preston	4,316
Queen Anne's County	1,902,080
Ridgely	16,692
Secretary	-
Sharptown	9,990
Snow Hill	47,873
Somerset County	931,724
St. Michaels	39,563
Sudlersville	3,020
Talbot County	777,663
Town of Betterton	3,467
Town of Brookview	-
Town of Cecilton	2,905
Town of Centreville	867,762
Town of Charlestown	8,043
Town of Chesapeake City	11,123
Town of Chestertown	44,907
Town of Church Creek	640
Town of Church Hill	9,452
Town of Denton	57,051
Town of Elkton	171,573
Town of Federalsburg	32,954
Town of Goldsboro	1,211
Town of Greensboro	24,842
Town of Henderson	1,420
Town of Hurlock	26,224
Town of Marydel	-
Town of Millington	2,370
Town of North East	57,047
Town of Ocean City	657,980
Town of Perryville	19,855
Town of Pittsville	10,915
Town of Port Deposit	16,540
Town of Prince Anne	67,554
Town of Queen Anne	-
Town of Queenstown	12,614
Town of Rising Sun	16,385
Town of Templeville	-
Town of Trappe	5,949
Town of Vienna	6,421
Town of Willards	13,427
Wicomico County	3,001,373
Worcester County	2,444,012
MD Other Property	300
Total	25,178,603

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, 2023

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) P.O. Box 8699 2301 Market Street 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 20068-001 (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
PECO ENERGY COMPANY: Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, \$25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	EXC/28	New York Stock Exchange

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 <input checked="" type="checkbox"/>	Accelerated Filer <input type="checkbox"/>	Non-accelerated Filer <input type="checkbox"/>	Smaller Reporting Company <input type="checkbox"/>	Emerging Growth Company <input type="checkbox"/>
Commonwealth Edison Company	Large Accelerated Filer <input type="checkbox"/>	Accelerated Filer <input type="checkbox"/>	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company <input type="checkbox"/>	Emerging Growth Company <input type="checkbox"/>
PECO Energy Company	Large Accelerated Filer <input type="checkbox"/>	Accelerated Filer <input type="checkbox"/>	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company <input type="checkbox"/>	Emerging Growth Company <input type="checkbox"/>
Baltimore Gas and Electric Company	Large Accelerated Filer <input type="checkbox"/>	Accelerated Filer <input type="checkbox"/>	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company <input type="checkbox"/>	Emerging Growth Company <input type="checkbox"/>
Pepco Holdings LLC	Large Accelerated Filer <input type="checkbox"/>	Accelerated Filer <input type="checkbox"/>	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company <input type="checkbox"/>	Emerging Growth Company <input type="checkbox"/>
Potomac Electric Power Company	Large Accelerated Filer <input type="checkbox"/>	Accelerated Filer <input type="checkbox"/>	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company <input type="checkbox"/>	Emerging Growth Company <input type="checkbox"/>
Delmarva Power & Light Company	Large Accelerated Filer <input type="checkbox"/>	Accelerated Filer <input type="checkbox"/>	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company <input type="checkbox"/>	Emerging Growth Company <input type="checkbox"/>
Atlantic City Electric Company	Large Accelerated Filer <input type="checkbox"/>	Accelerated Filer <input type="checkbox"/>	Non-accelerated Filer <input checked="" type="checkbox"/>	Smaller Reporting Company <input type="checkbox"/>	Emerging Growth Company <input type="checkbox"/>

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, 2023 was:

Exelon Corporation Common Stock, without par value	994,568,998
Commonwealth Edison Company Common Stock, \$12.50 par value	127,021,394
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

<i>Exelon</i>	Exelon Corporation
<i>ComEd</i>	Commonwealth Edison Company
<i>PECO</i>	PECO Energy Company
<i>BGE</i>	Baltimore Gas and Electric Company
<i>Pepco Holdings or PHI</i>	Pepco Holdings LLC
<i>Pepco</i>	Potomac Electric Power Company
<i>DPL</i>	Delmarva Power & Light Company
<i>ACE</i>	Atlantic City Electric Company
<i>Registrants</i>	Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, collectively
<i>Utility Registrants</i>	ComEd, PECO, BGE, Pepco, DPL, and ACE, collectively
<i>BSC</i>	Exelon Business Services Company, LLC
<i>Exelon Corporate</i>	Exelon in its corporate capacity as a holding company
<i>PCI</i>	Potomac Capital Investment Corporation and its subsidiaries
<i>PECO Trust III</i>	PECO Energy Capital Trust III
<i>PECO Trust IV</i>	PECO Energy Capital Trust IV
<i>PHI Corporate</i>	PHI in its corporate capacity as a holding company
<i>PHISCO</i>	PHI Service Company

Former Related Entities

<i>Constellation</i>	Constellation Energy Corporation
<i>Generation</i>	Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC, a subsidiary of Exelon prior to separation on February 1, 2022)

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

<i>Note - of the 2022 Form 10-K</i>	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2022 Annual Report on Form 10-K
<i>ABO</i>	Accumulated Benefit Obligation
<i>AECs</i>	Alternative Energy Credits that are issued for each megawatt hour of generation from a qualified alternative energy source
<i>AFUDC</i>	Allowance for Funds Used During Construction
<i>AMI</i>	Advanced Metering Infrastructure
<i>AOCI</i>	Accumulated Other Comprehensive Income (Loss)
<i>ARO</i>	Asset Retirement Obligation
<i>BGS</i>	Basic Generation Service
<i>BSA</i>	Bill Stabilization Adjustment
<i>CEJA</i>	Climate and Equitable Jobs Act; Illinois Public Act 102-0662 signed into law on September 15, 2021
<i>CERCLA</i>	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
<i>CIP</i>	Conservation Incentive Program
<i>CMC</i>	Carbon Mitigation Credit
<i>CODMs</i>	Chief Operating Decision Maker(s)
<i>DC PLUG</i>	District of Columbia Power Line Undergrounding Initiative
<i>DCPSC</i>	Public Service Commission of the District of Columbia
<i>DEPSC</i>	Delaware Public Service Commission
<i>DOEE</i>	District of Columbia Department of Energy & Environment
<i>DPA</i>	Deferred Prosecution Agreement
<i>DPP</i>	Deferred Purchase Price
<i>DSIC</i>	Distribution System Improvement Charge
<i>EIMA</i>	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
<i>EPA</i>	United States Environmental Protection Agency
<i>ERCOT</i>	Electric Reliability Council of Texas
<i>ERISA</i>	Employee Retirement Income Security Act of 1974, as amended
<i>ERP</i>	Enterprise Resource Program
<i>ETAC</i>	Energy Transition Assistance Charge
<i>FEJA</i>	Illinois Public Act 99-0906 or Future Energy Jobs Act
<i>FERC</i>	Federal Energy Regulatory Commission
<i>GAAP</i>	Generally Accepted Accounting Principles in the United States
<i>GCR</i>	Gas Cost Rate
<i>GSA</i>	Generation Supply Adjustment
<i>GWhs</i>	Gigawatt hours
<i>ICC</i>	Illinois Commerce Commission
<i>IJA</i>	Infrastructure Investment and Jobs Act
<i>Illinois Settlement Legislation</i>	Legislation enacted in 2007 affecting electric utilities in Illinois
<i>IPA</i>	Illinois Power Agency
<i>IRA</i>	Inflation Reduction Act
<i>IRC</i>	Internal Revenue Code
<i>IRS</i>	Internal Revenue Service
<i>MDPSC</i>	Maryland Public Service Commission
<i>MGP</i>	Manufactured Gas Plant

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

<i>mmcf</i>	Million Cubic Feet
<i>MMG</i>	Middle Mile Grant
<i>MRP</i>	Multi-Year Rate Plan
<i>MWh</i>	Megawatt hour
<i>N/A</i>	Not applicable
<i>NAV</i>	Net Asset Value
<i>NDT</i>	Nuclear Decommissioning Trust
<i>NJBPU</i>	New Jersey Board of Public Utilities
<i>NPNS</i>	Normal Purchase Normal Sale scope exception
<i>NPS</i>	National Park Service
<i>NRD</i>	Natural Resources Damages
<i>OCI</i>	Other Comprehensive Income
<i>OPEB</i>	Other Postretirement Employee Benefits
<i>PAPUC</i>	Pennsylvania Public Utility Commission
<i>PGC</i>	Purchased Gas Cost Clause
<i>PJM</i>	PJM Interconnection, LLC
<i>POLR</i>	Provider of Last Resort
<i>PPA</i>	Power Purchase Agreement
<i>PP&E</i>	Property, plant, and equipment
<i>PRPs</i>	Potentially Responsible Parties
<i>REC</i>	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
<i>Regulatory Agreement Units</i>	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
<i>RFP</i>	Request for Proposal
<i>Rider</i>	Reconcilable Surcharge Recovery Mechanism
<i>ROE</i>	Return on equity
<i>ROU</i>	Right-of-use
<i>RPS</i>	Renewable Energy Portfolio Standards
<i>RTO</i>	Regional Transmission Organization
<i>SEC</i>	United States Securities and Exchange Commission
<i>SOFR</i>	Secured Overnight Financing Rate
<i>SOS</i>	Standard Offer Service
<i>STRIDE</i>	Maryland Strategic Infrastructure Development and Enhancement Program
<i>TCJA</i>	Tax Cuts and Jobs Act
<i>ZEC</i>	Zero Emission Credit or Zero Emission Certificate

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 the Private Securities Litigation Reform Act of 1995 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.

The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) the 2022 Form 10-K in (a) Part I, ITEM 1A, Risk Factors, (b) Part II, ITEM 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part II, ITEM 8, Financial Statements and Supplementary Data: Note 18, Commitments and Contingencies; (2) this Quarterly Report on Form 10-Q in (a) Part II, ITEM 1A, Risk Factors, (b) Part I, ITEM 2, Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part I, ITEM 1, Financial Statements: Note 12, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants.

Investors are cautioned not to place undue reliance on these forward-looking statements, 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 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.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions, except per share data)	Three Months Ended March 31,	
	2023	2022
Operating revenues		
Electric operating revenues	\$ 4,462	\$ 4,481
Natural gas operating revenues	822	817
Revenues from alternative revenue programs	279	29
Total operating revenues	<u>5,563</u>	<u>5,327</u>
Operating expenses		
Purchased power	1,733	1,581
Purchased fuel	358	338
Purchased power and fuel from affiliates	—	159
Operating and maintenance	1,151	1,178
Depreciation and amortization	860	817
Taxes other than income taxes	355	354
Total operating expenses	<u>4,457</u>	<u>4,427</u>
Operating income	<u>1,106</u>	<u>900</u>
Other income and (deductions)		
Interest expense, net	(406)	(332)
Interest expense to affiliates	(6)	(6)
Other, net	109	137
Total other income and (deductions)	<u>(303)</u>	<u>(201)</u>
Income from continuing operations before income taxes	<u>803</u>	<u>699</u>
Income taxes	<u>134</u>	<u>218</u>
Net income from continuing operations after income taxes	<u>669</u>	<u>481</u>
Net income from discontinued operations after income taxes (Note 2)	<u>—</u>	<u>117</u>
Net income	<u>669</u>	<u>598</u>
Net income attributable to noncontrolling interests	<u>—</u>	<u>1</u>
Net income attributable to common shareholders	<u>\$ 669</u>	<u>\$ 597</u>
Amounts attributable to common shareholders:		
Net income from continuing operations	669	481
Net income from discontinued operations	—	116
Net income attributable to common shareholders	<u>\$ 669</u>	<u>\$ 597</u>
Comprehensive income, net of income taxes		
Net income	\$ 669	\$ 598
Other comprehensive income (loss), net of income taxes		
Pension and non-pension postretirement benefit plans:		
Actuarial loss reclassified to periodic benefit cost	3	14
Pension and non-pension postretirement benefit plan valuation adjustment	(10)	—
Unrealized gain on cash flow hedges	6	—
Other comprehensive (loss) income	<u>(1)</u>	<u>14</u>
Comprehensive income	<u>668</u>	<u>612</u>
Comprehensive income attributable to noncontrolling interests	<u>—</u>	<u>1</u>
Comprehensive income attributable to common shareholders	<u>\$ 668</u>	<u>\$ 611</u>
Average shares of common stock outstanding:		
Basic	995	981
Assumed exercise and/or distributions of stock-based awards	1	—
Diluted	<u>996</u>	<u>981</u>
Earnings per average common share from continuing operations		
Basic	\$ 0.67	\$ 0.49
Diluted	\$ 0.67	\$ 0.49
Earnings per average common share from discontinued operations		
Basic	\$ —	\$ 0.12
Diluted	\$ —	\$ 0.12

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Cash flows from operating activities		
Net income	\$ 669	\$ 598
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	860	1,024
Gain on sales of assets and businesses	—	(10)
Deferred income taxes and amortization of investment tax credits	113	110
Net fair value changes related to derivatives	—	(59)
Net realized and unrealized losses on NDT funds	—	205
Net unrealized losses on equity investments	—	16
Other non-cash operating activities	(138)	232
Changes in assets and liabilities:		
Accounts receivable	106	(711)
Inventories	102	125
Accounts payable and accrued expenses	(482)	291
Option premiums paid, net	—	(39)
Collateral (paid) received, net	(214)	1,142
Income taxes	23	77
Regulatory assets and liabilities, net	(324)	(31)
Pension and non-pension postretirement benefit contributions	(44)	(574)
Other assets and liabilities	(187)	(614)
Net cash flows provided by operating activities	<u>484</u>	<u>1,782</u>
Cash flows from investing activities		
Capital expenditures	(1,881)	(1,922)
Proceeds from NDT fund sales	—	488
Investment in NDT funds	—	(516)
Collection of DPP	—	169
Proceeds from sales of assets and businesses	—	16
Other investing activities	10	(54)
Net cash flows used in investing activities	<u>(1,871)</u>	<u>(1,819)</u>
Cash flows from financing activities		
Changes in short-term borrowings	(1,130)	(700)
Proceeds from short-term borrowings with maturities greater than 90 days	—	1,150
Repayments on short-term borrowings with maturities greater than 90 days	(150)	(350)
Issuance of long-term debt	3,925	4,301
Retirement of long-term debt	(857)	(6)
Dividends paid on common stock	(358)	(332)
Proceeds from employee stock plans	10	9
Transfer of cash, restricted cash, and cash equivalents to Constellation	—	(2,594)
Other financing activities	(60)	(62)
Net cash flows provided by financing activities	<u>1,380</u>	<u>1,416</u>
(Decrease) increase in cash, restricted cash, and cash equivalents	<u>(7)</u>	<u>1,379</u>
Cash, restricted cash, and cash equivalents at beginning of period	<u>1,090</u>	<u>1,619</u>
Cash, restricted cash, and cash equivalents at end of period	<u>\$ 1,083</u>	<u>\$ 2,998</u>
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (201)	\$ (322)
Increase in DPP	—	348
Decrease in PP&E related to ARO update	—	(335)

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	ASSETS	March 31, 2023	December 31, 2022
Current assets			
Cash and cash equivalents		\$ 522	\$ 407
Restricted cash and cash equivalents		381	566
Accounts receivable			
Customer accounts receivable	2,493	2,544	
Customer allowance for credit losses	(389)	(327)	
Customer accounts receivable, net		2,104	2,217
Other accounts receivable	1,346	1,426	
Other allowance for credit losses	(91)	(82)	
Other accounts receivable, net		1,255	1,344
Inventories, net			
Fossil fuel		70	208
Materials and supplies		582	547
Regulatory assets		2,386	1,641
Other		477	406
Total current assets		7,777	7,336
Property, plant, and equipment (net of accumulated depreciation and amortization of \$16,384 and \$15,930 as of March 31, 2023 and December 31, 2022, respectively)		70,117	69,076
Deferred debits and other assets			
Regulatory assets		7,878	8,037
Goodwill		6,630	6,630
Receivable related to Regulatory Agreement Units		3,069	2,897
Investments		234	232
Other		1,220	1,141
Total deferred debits and other assets		19,031	18,937
Total assets		\$ 96,925	\$ 95,349

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	\$ 1,306	\$ 2,586
Long-term debt due within one year	1,356	1,802
Accounts payable	2,762	3,382
Accrued expenses	1,183	1,226
Payables to affiliates	5	5
Regulatory liabilities	472	437
Mark-to-market derivative liabilities	23	8
Unamortized energy contract liabilities	9	10
Other	976	1,155
Total current liabilities	<u>8,092</u>	<u>10,611</u>
Long-term debt	38,732	35,272
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,483	11,250
Regulatory liabilities	9,307	9,112
Pension obligations	1,101	1,109
Non-pension postretirement benefit obligations	506	507
Asset retirement obligations	270	269
Mark-to-market derivative liabilities	77	83
Unamortized energy contract liabilities	32	35
Other	1,869	1,967
Total deferred credits and other liabilities	<u>24,645</u>	<u>24,332</u>
Total liabilities	<u>71,859</u>	<u>70,605</u>
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 994 shares outstanding as of March 31, 2023 and December 31, 2022)	20,921	20,908
Treasury stock, at cost (2 shares as of March 31, 2023 and December 31, 2022)	(123)	(123)
Retained earnings	4,907	4,597
Accumulated other comprehensive loss, net	(639)	(638)
Total shareholders' equity	<u>25,066</u>	<u>24,744</u>
Total liabilities and shareholders' equity	\$ 96,925	\$ 95,349

See the Combined Notes to Consolidated Financial Statements
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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions, shares in thousands)	Three Months Ended March 31, 2023						
	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2022	995,830	\$ 20,908	\$ (123)	\$ 4,597	\$ (638)	\$ —	\$ 24,744
Net income	—	—	—	669	—	—	669
Long-term incentive plan activity	306	1	—	—	—	—	1
Employee stock purchase plan issuances	266	12	—	—	—	—	12
Common stock dividends (\$0.36/common share)	—	—	—	(359)	—	—	(359)
Other comprehensive loss, net of income taxes	—	—	—	—	(1)	—	(1)
Balance, March 31, 2023	<u>996,402</u>	<u>\$ 20,921</u>	<u>\$ (123)</u>	<u>\$ 4,907</u>	<u>\$ (639)</u>	<u>\$ —</u>	<u>\$ 25,066</u>

(In millions, shares in thousands)	Three Months Ended March 31, 2022						
	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2021	981,291	\$ 20,324	\$ (123)	\$ 16,942	\$ (2,750)	\$ 402	\$ 34,795
Net income	—	—	—	597	—	1	598
Long-term incentive plan activity	540	(13)	—	—	—	—	(13)
Employee stock purchase plan issuances	211	9	—	—	—	—	9
Changes in equity of noncontrolling interests	—	—	—	—	—	(7)	(7)
Distribution of Constellation (Note 2)	—	(21)	—	(13,179)	2,023	(396)	(11,573)
Common stock dividends (\$0.34/common share)	—	—	—	(332)	—	—	(332)
Other comprehensive income, net of income taxes	—	—	—	—	14	—	14
Balance, March 31, 2022	<u>982,042</u>	<u>\$ 20,299</u>	<u>\$ (123)</u>	<u>\$ 4,028</u>	<u>\$ (713)</u>	<u>\$ —</u>	<u>\$ 23,491</u>

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended	
	2023	2022
Operating revenues		
Electric operating revenues	\$ 1,511	\$ 1,688
Revenues from alternative revenue programs	153	40
Operating revenues from affiliates	3	6
Total operating revenues	1,667	1,734
Operating expenses		
Purchased power	488	579
Purchased power from affiliate	—	59
Operating and maintenance	254	266
Operating and maintenance from affiliates	83	85
Depreciation and amortization	338	321
Taxes other than income taxes	93	96
Total operating expenses	1,256	1,406
Operating income	411	328
Other income and (deductions)		
Interest expense, net	(114)	(97)
Interest expense to affiliates	(3)	(3)
Other, net	18	12
Total other income and (deductions)	(99)	(88)
Income before income taxes	312	240
Income taxes	71	52
Net income	\$ 241	\$ 188
Comprehensive income	\$ 241	\$ 188

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Cash flows from operating activities		
Net income	\$ 241	\$ 188
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	338	321
Deferred income taxes and amortization of investment tax credits	55	54
Other non-cash operating activities	(153)	(9)
Changes in assets and liabilities:		
Accounts receivable	96	(45)
Receivables from and payables to affiliates, net	10	(42)
Inventories	(21)	3
Accounts payable and accrued expenses	(306)	(154)
Collateral (paid) received, net	(4)	43
Income taxes	15	(2)
Regulatory assets and liabilities, net	(338)	(8)
Pension and non-pension postretirement benefit contributions	(23)	(176)
Other assets and liabilities	(22)	(29)
Net cash flows (used in) provided by operating activities	<u>(112)</u>	<u>144</u>
Cash flows from investing activities		
Capital expenditures	(617)	(617)
Other investing activities	1	7
Net cash flows used in investing activities	<u>(616)</u>	<u>(610)</u>
Cash flows from financing activities		
Changes in short-term borrowings	(18)	—
Repayments on short-term borrowings with maturities greater than 90 days	(150)	—
Issuance of long-term debt	975	750
Dividends paid on common stock	(187)	(144)
Contributions from parent	186	167
Other financing activities	(11)	(10)
Net cash flows provided by financing activities	<u>795</u>	<u>763</u>
Increase in cash, restricted cash, and cash equivalents	<u>67</u>	<u>297</u>
Cash, restricted cash, and cash equivalents at beginning of period	<u>511</u>	<u>384</u>
Cash, restricted cash, and cash equivalents at end of period	<u>\$ 578</u>	<u>\$ 681</u>
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (35)	\$ (50)

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	ASSETS	March 31, 2023	December 31, 2022
Current assets			
Cash and cash equivalents		\$ 75	\$ 67
Restricted cash and cash equivalents		323	327
Accounts receivable			
Customer accounts receivable	674	558	
Customer allowance for credit losses	(74)	(59)	
Customer accounts receivable, net		600	499
Other accounts receivable	233	441	
Other allowance for credit losses	(18)	(17)	
Other accounts receivable, net		215	424
Receivables from affiliates		3	3
Inventories, net		216	196
Regulatory assets		1,472	775
Other		102	92
Total current assets		3,006	2,383
Property, plant, and equipment (net of accumulated depreciation and amortization of \$6,838 and \$6,673 as of March 31, 2023 and December 31, 2022, respectively)		27,858	27,513
Deferred debits and other assets			
Regulatory assets		2,517	2,667
Goodwill		2,625	2,625
Receivable related to Regulatory Agreement Units		2,804	2,660
Investments		6	6
Prepaid pension asset		1,225	1,206
Other		679	601
Total deferred debits and other assets		9,856	9,765
Total assets		\$ 40,720	\$ 39,661

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	\$ 409	\$ 577
Accounts payable	801	1,010
Accrued expenses	305	415
Payables to affiliates	84	74
Customer deposits	109	108
Regulatory liabilities	233	226
Mark-to-market derivative liabilities	22	5
Other	189	191
Total current liabilities	<u>2,152</u>	<u>2,606</u>
Long-term debt	11,480	10,518
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,100	5,021
Regulatory liabilities	7,143	6,913
Asset retirement obligations	149	148
Non-pension postretirement benefits obligations	167	165
Mark-to-market derivative liabilities	76	79
Other	644	642
Total deferred credits and other liabilities	<u>13,279</u>	<u>12,968</u>
Total liabilities	<u>27,116</u>	<u>26,297</u>
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	9,932	9,746
Retained earnings	2,084	2,030
Total shareholders' equity	<u>13,604</u>	<u>13,364</u>
Total liabilities and shareholders' equity	<u>\$ 40,720</u>	<u>\$ 39,661</u>

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Three Months Ended March 31, 2023			
	Common Stock	Other Paid-In Capital	Retained Earnings	Total Shareholders' Equity
Balance, December 31, 2022	\$ 1,588	\$ 9,746	\$ 2,030	\$ 13,364
Net income	—	—	241	241
Common stock dividends	—	—	(187)	(187)
Contributions from parent	—	186	—	186
Balance, March 31, 2023	<u>\$ 1,588</u>	<u>\$ 9,932</u>	<u>\$ 2,084</u>	<u>\$ 13,604</u>

(In millions)	Three Months Ended March 31, 2022			
	Common Stock	Other Paid-In Capital	Retained Earnings	Total Shareholders' Equity
Balance, December 31, 2021	\$ 1,588	\$ 9,076	\$ 1,691	\$ 12,355
Net income	—	—	188	188
Common stock dividends	—	—	(144)	(144)
Contributions from parent	—	167	—	167
Balance, March 31, 2022	<u>\$ 1,588</u>	<u>\$ 9,243</u>	<u>\$ 1,735</u>	<u>\$ 12,566</u>

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended	
	2023	March 31, 2022
Operating revenues		
Electric operating revenues	\$ 798	\$ 734
Natural gas operating revenues	316	306
Revenues from alternative revenue programs	(4)	6
Operating revenues from affiliates	2	1
Total operating revenues	<u>1,112</u>	<u>1,047</u>
Operating expenses		
Purchased power	330	229
Purchased fuel	154	145
Purchased power from affiliate	—	33
Operating and maintenance	219	196
Operating and maintenance from affiliates	51	51
Depreciation and amortization	98	92
Taxes other than income taxes	50	47
Total operating expenses	<u>902</u>	<u>793</u>
Operating income	<u>210</u>	<u>254</u>
Other income and (deductions)		
Interest expense, net	(45)	(38)
Interest expense to affiliates	(3)	(3)
Other, net	8	7
Total other income and (deductions)	<u>(40)</u>	<u>(34)</u>
Income before income taxes	<u>170</u>	<u>220</u>
Income taxes	<u>4</u>	<u>14</u>
Net income	<u>\$ 166</u>	<u>\$ 206</u>
Comprehensive income	<u>\$ 166</u>	<u>\$ 206</u>

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Cash flows from operating activities		
Net income	\$ 166	\$ 206
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	98	92
Deferred income taxes and amortization of investment tax credits	(16)	14
Other non-cash operating activities	32	15
Changes in assets and liabilities:		
Accounts receivable	36	(40)
Receivables from and payables to affiliates, net	8	(31)
Inventories	60	27
Accounts payable and accrued expenses	(176)	(24)
Income taxes	20	—
Regulatory assets and liabilities, net	15	(4)
Pension and non-pension postretirement benefit contributions	—	(12)
Other assets and liabilities	(75)	(102)
Net cash flows provided by operating activities	<u>168</u>	<u>141</u>
Cash flows from investing activities		
Capital expenditures	(335)	(344)
Other investing activities	—	2
Net cash flows used in investing activities	<u>(335)</u>	<u>(342)</u>
Cash flows from financing activities		
Changes in short-term borrowings	(94)	—
Changes in Exelon intercompany money pool	—	65
Dividends paid on common stock	(101)	(100)
Contributions from parent	330	227
Other financing activities	—	(1)
Net cash flows provided by financing activities	<u>135</u>	<u>191</u>
Decrease in cash, restricted cash, and cash equivalents	<u>(32)</u>	<u>(10)</u>
Cash, restricted cash, and cash equivalents at beginning of period	<u>68</u>	<u>44</u>
Cash, restricted cash, and cash equivalents at end of period	<u>\$ 36</u>	<u>\$ 34</u>
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (9)	\$ (41)

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	ASSETS		March 31, 2023	December 31, 2022
Current assets				
Cash and cash equivalents		\$	27	\$ 59
Restricted cash and cash equivalents			9	9
Accounts receivable				
Customer accounts receivable	588			635
Customer allowance for credit losses	(130)			(105)
Customer accounts receivable, net			458	530
Other accounts receivable	147			153
Other allowance for credit losses	(11)			(9)
Other accounts receivable, net			136	144
Receivables from affiliates			2	4
Inventories, net				
Fossil fuel			41	99
Materials and supplies			50	52
Prepaid utility taxes			100	—
Regulatory assets			83	80
Other			43	38
Total current assets			949	1,015
Property, plant, and equipment (net of accumulated depreciation and amortization of \$4,135 and \$4,078 as of March 31, 2023 and December 31, 2022, respectively)			12,359	12,125
Deferred debits and other assets				
Regulatory assets			693	652
Receivable related to Regulatory Agreement Units			265	237
Investments			31	30
Prepaid pension asset			417	413
Other			24	30
Total deferred debits and other assets			1,430	1,362
Total assets		\$	14,738	\$ 14,502

See the Combined Notes to Consolidated Financial Statements
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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	LIABILITIES AND SHAREHOLDER'S EQUITY		March 31, 2023	December 31, 2022
Current liabilities				
Short-term borrowings		\$	145	\$ 239
Long-term debt due within one year			50	50
Accounts payable			543	668
Accrued expenses			95	142
Payables to affiliates			48	42
Customer deposits			66	63
Regulatory liabilities			95	75
Other			50	32
Total current liabilities			1,092	1,311
Long-term debt			4,563	4,562
Long-term debt to financing trusts			184	184
Deferred credits and other liabilities				
Deferred income taxes and unamortized investment tax credits			2,245	2,213
Regulatory liabilities			295	270
Asset retirement obligations			28	28
Non-pension postretirement benefits obligations			286	286
Other			87	85
Total deferred credits and other liabilities			2,941	2,882
Total liabilities			8,780	8,939
Commitments and contingencies				
Shareholder's equity				
Common stock			4,032	3,702
Retained earnings			1,926	1,861
Total shareholder's equity			5,958	5,563
Total liabilities and shareholder's equity		\$	14,738	\$ 14,502

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Three Months Ended March 31, 2023		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2022	\$ 3,702	\$ 1,861	\$ 5,563
Net income	—	166	166
Common stock dividends	—	(101)	(101)
Contributions from parent	330	—	330
Balance, March 31, 2023	\$ 4,032	\$ 1,926	\$ 5,958

(In millions)	Three Months Ended March 31, 2022		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2021	\$ 3,428	\$ 1,684	\$ 5,112
Net income	—	206	206
Common stock dividends	—	(100)	(100)
Contributions from parent	227	—	227
Balance, March 31, 2022	\$ 3,655	\$ 1,790	\$ 5,445

See the Combined Notes to Consolidated Financial Statements
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BALTIMORE GAS AND ELECTRIC COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended	
	2023	2022
Operating revenues		
Electric operating revenues	\$ 780	\$ 735
Natural gas operating revenues	409	424
Revenues from alternative revenue programs	65	(12)
Operating revenues from affiliates	3	7
Total operating revenues	<u>1,257</u>	<u>1,154</u>
Operating expenses		
Purchased power	343	285
Purchased fuel	149	151
Purchased power from affiliate	—	18
Operating and maintenance	168	167
Operating and maintenance from affiliates	54	51
Depreciation and amortization	167	171
Taxes other than income taxes	83	76
Total operating expenses	<u>964</u>	<u>919</u>
Operating income	<u>293</u>	<u>235</u>
Other income and (deductions)		
Interest expense, net	(44)	(35)
Other, net	3	7
Total other income and (deductions)	<u>(41)</u>	<u>(28)</u>
Income before income taxes	<u>252</u>	<u>207</u>
Income taxes	<u>52</u>	<u>9</u>
Net income	<u>\$ 200</u>	<u>\$ 198</u>
Comprehensive income	<u>\$ 200</u>	<u>\$ 198</u>

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Cash flows from operating activities		
Net income	\$ 200	\$ 198
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	167	171
Deferred income taxes and amortization of investment tax credits	24	5
Other non-cash operating activities	(32)	44
Changes in assets and liabilities:		
Accounts receivable	43	(80)
Receivables from and payables to affiliates, net	(3)	(2)
Inventories	62	32
Accounts payable and accrued expenses	(96)	(30)
Collateral (paid) received, net	(22)	30
Income taxes	29	4
Regulatory assets and liabilities, net	(31)	(8)
Pension and non-pension postretirement benefit contributions	(8)	(56)
Other assets and liabilities	(24)	(31)
Net cash flows provided by operating activities	<u>309</u>	<u>277</u>
Cash flows from investing activities		
Capital expenditures	(350)	(303)
Other investing activities	3	3
Net cash flows used in investing activities	<u>(347)</u>	<u>(300)</u>
Cash flows from financing activities		
Changes in short-term borrowings	(165)	120
Dividends paid on common stock	(80)	(76)
Contributions from parent	237	—
Other financing activities	—	(1)
Net cash flows (used in) provided by financing activities	<u>(8)</u>	<u>43</u>
(Decrease) increase in cash, restricted cash, and cash equivalents	<u>(46)</u>	<u>20</u>
Cash, restricted cash, and cash equivalents at beginning of period	<u>67</u>	<u>55</u>
Cash, restricted cash, and cash equivalents at end of period	<u>\$ 21</u>	<u>\$ 75</u>
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (70)	\$ (32)

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	ASSETS	March 31, 2023	December 31, 2022
Current assets			
Cash and cash equivalents		\$ 20	\$ 43
Restricted cash and cash equivalents		1	24
Accounts receivable			
Customer accounts receivable	581	617	
Customer allowance for credit losses	(73)	(54)	
Customer accounts receivable, net		508	563
Other accounts receivable	128	132	
Other allowance for credit losses	(12)	(10)	
Other accounts receivable, net		116	122
Inventories, net			
Fossil fuel		23	91
Materials and supplies		71	65
Prepaid utility taxes		49	52
Regulatory assets		237	177
Other		13	13
Total current assets		1,038	1,150
Property, plant, and equipment (net of accumulated depreciation and amortization of \$4,658 and \$4,583 as of March 31, 2023 and December 31, 2022, respectively)		11,493	11,338
Deferred debits and other assets			
Regulatory assets		533	527
Investments		9	7
Prepaid pension asset		280	291
Other		58	37
Total deferred debits and other assets		880	862
Total assets		\$ 13,411	\$ 13,350

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ 243	\$ 408
Long-term debt due within one year	300	300
Accounts payable	310	462
Accrued expenses	174	159
Payables to affiliates	37	39
Customer deposits	107	105
Regulatory liabilities	61	47
Other	34	55
Total current liabilities	<u>1,266</u>	<u>1,575</u>
Long-term debt	<u>3,908</u>	<u>3,907</u>
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,878	1,832
Regulatory liabilities	791	816
Asset retirement obligations	30	30
Non-pension postretirement benefits obligations	161	166
Other	84	88
Total deferred credits and other liabilities	<u>2,944</u>	<u>2,932</u>
Total liabilities	<u>8,118</u>	<u>8,414</u>
Commitments and contingencies		
Shareholder's equity		
Common stock	3,098	2,861
Retained earnings	2,195	2,075
Total shareholder's equity	<u>5,293</u>	<u>4,936</u>
Total liabilities and shareholder's equity	<u>\$ 13,411</u>	<u>\$ 13,350</u>

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Three Months Ended March 31, 2023		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2022	\$ 2,861	\$ 2,075	\$ 4,936
Net income	—	200	200
Common stock dividends	—	(80)	(80)
Contributions from parent	237	—	237
Balance, March 31, 2023	\$ 3,098	\$ 2,195	\$ 5,293
(In millions)	Three Months Ended March 31, 2022		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2021	\$ 2,575	\$ 1,995	\$ 4,570
Net income	—	198	198
Common stock dividends	—	(76)	(76)
Balance, March 31, 2022	\$ 2,575	\$ 2,117	\$ 4,692

See the Combined Notes to Consolidated Financial Statements

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended	
	2023	2022
Operating revenues		
Electric operating revenues	\$ 1,371	\$ 1,323
Natural gas operating revenues	97	83
Revenues from alternative revenue programs	65	(5)
Operating revenues from affiliates	3	3
Total operating revenues	<u>1,536</u>	<u>1,404</u>
Operating expenses		
Purchased power	572	487
Purchased fuel	55	42
Purchased power from affiliate	—	50
Operating and maintenance	267	248
Operating and maintenance from affiliates	42	51
Depreciation and amortization	241	218
Taxes other than income taxes	120	119
Total operating expenses	<u>1,297</u>	<u>1,215</u>
Operating income	<u>239</u>	<u>189</u>
Other income and (deductions)		
Interest expense, net	(76)	(69)
Other, net	26	17
Total other income and (deductions)	<u>(50)</u>	<u>(52)</u>
Income before income taxes	<u>189</u>	<u>137</u>
Income taxes	<u>34</u>	<u>7</u>
Net income	<u>\$ 155</u>	<u>\$ 130</u>
Comprehensive income	<u>\$ 155</u>	<u>\$ 130</u>

See the Combined Notes to Consolidated Financial Statements
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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Cash flows from operating activities		
Net income	\$ 155	\$ 130
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	241	218
Deferred income taxes and amortization of investment tax credits	13	2
Other non-cash operating activities	(7)	35
Changes in assets and liabilities:		
Accounts receivable	98	(21)
Receivables from and payables to affiliates, net	—	(51)
Inventories	4	7
Accounts payable and accrued expenses	(88)	(23)
Collateral (paid) received, net	(189)	37
Income taxes	20	5
Regulatory assets and liabilities, net	27	(18)
Pension and non-pension postretirement benefit contributions	(7)	(67)
Other assets and liabilities	(11)	(22)
Net cash flows provided by operating activities	<u>256</u>	<u>232</u>
Cash flows from investing activities		
Capital expenditures	(561)	(409)
Other investing activities	8	2
Net cash flows used in investing activities	<u>(553)</u>	<u>(407)</u>
Cash flows from financing activities		
Changes in short-term borrowings	(414)	(468)
Issuance of long-term debt	450	700
Changes in Exelon intercompany money pool	8	39
Distributions to member	(112)	(102)
Contributions from member	405	704
Other financing activities	(17)	(9)
Net cash flows provided by financing activities	<u>320</u>	<u>864</u>
Increase in cash, restricted cash, and cash equivalents	<u>23</u>	<u>689</u>
Cash, restricted cash, and cash equivalents at beginning of period	<u>373</u>	<u>213</u>
Cash, restricted cash, and cash equivalents at end of period	<u>\$ 396</u>	<u>\$ 902</u>
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (76)	\$ (55)

See the Combined Notes to Consolidated Financial Statements
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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	ASSETS	March 31, 2023	December 31, 2022
Current assets			
Cash and cash equivalents		\$ 367	\$ 198
Restricted cash and cash equivalents		29	175
Accounts receivable			
Customer accounts receivable	650	734	
Customer allowance for credit losses	(112)	(109)	
Customer accounts receivable, net		538	625
Other accounts receivable	280	300	
Other allowance for credit losses	(50)	(46)	
Other accounts receivable, net		230	254
Receivables from affiliates		2	2
Inventories, net			
Fossil fuel		5	18
Materials and supplies		245	236
Regulatory assets		439	455
Other		68	96
Total current assets		1,923	2,059
Property, plant, and equipment (net of accumulated depreciation and amortization of \$2,757 and \$2,618 as of March 31, 2023 and December 31, 2022, respectively)		18,003	17,686
Deferred debits and other assets			
Regulatory assets		1,579	1,610
Goodwill		4,005	4,005
Investments		139	138
Prepaid pension asset		332	353
Other		227	231
Total deferred debits and other assets		6,282	6,337
Total assets		\$ 26,208	\$ 26,082

See the Combined Notes to Consolidated Financial Statements

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2023	December 31, 2022
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ —	\$ 414
Long-term debt due within one year	998	591
Accounts payable	634	771
Accrued expenses	252	260
Payables to affiliates	66	66
Borrowings from Exelon intercompany money pool	52	44
Customer deposits	92	88
Regulatory liabilities	69	76
Unamortized energy contract liabilities	9	10
PPA termination obligation	87	87
Other	149	330
Total current liabilities	2,408	2,737
Long-term debt		
	7,555	7,529
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,934	2,895
Regulatory liabilities	976	1,011
Asset retirement obligations	59	59
Non-pension postretirement benefit obligations	46	50
Unamortized energy contract liabilities	32	35
Other	520	536
Total deferred credits and other liabilities	4,567	4,586
Total liabilities	14,530	14,852
Commitments and contingencies		
Member's equity		
Membership interest	11,987	11,582
Undistributed losses	(309)	(352)
Total member's equity	11,678	11,230
Total liabilities and member's equity	\$ 26,208	\$ 26,082

See the Combined Notes to Consolidated Financial Statements

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
(Unaudited)

(In millions)	Three Months Ended March 31, 2023		
	Membership Interest	Undistributed (Losses)/Gains	Total Member's Equity
Balance, December 31, 2022	\$ 11,582	\$ (352)	\$ 11,230
Net income	—	155	155
Distributions to member	—	(112)	(112)
Contributions from member	405	—	405
Balance, March 31, 2023	<u>\$ 11,987</u>	<u>\$ (309)</u>	<u>\$ 11,678</u>

(In millions)	Three Months Ended March 31, 2022		
	Membership Interest	Undistributed (Losses)/Gains	Total Member's Equity
Balance, December 31, 2021	\$ 10,795	\$ (210)	\$ 10,585
Net income	—	130	130
Distributions to member	—	(102)	(102)
Contributions from member	704	—	704
Balance, March 31, 2022	<u>\$ 11,499</u>	<u>\$ (182)</u>	<u>\$ 11,317</u>

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Operating revenues		
Electric operating revenues	\$ 670	\$ 620
Revenues from alternative revenue programs	39	(7)
Operating revenues from affiliates	1	1
Total operating revenues	710	614
Operating expenses		
Purchased power	258	174
Purchased power from affiliate	—	39
Operating and maintenance	93	73
Operating and maintenance from affiliates	57	58
Depreciation and amortization	108	108
Taxes other than income taxes	94	95
Total operating expenses	610	547
Operating income	100	67
Other income and (deductions)		
Interest expense, net	(39)	(36)
Other, net	16	13
Total other income and (deductions)	(23)	(23)
Income before income taxes	77	44
Income taxes	12	(2)
Net income	\$ 65	\$ 46
Comprehensive income	\$ 65	\$ 46

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Cash flows from operating activities		
Net income	\$ 65	\$ 46
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	108	108
Deferred income taxes and amortization of investment tax credits	3	(2)
Other non-cash operating activities	(10)	12
Changes in assets and liabilities:		
Accounts receivable	52	(2)
Receivables from and payables to affiliates, net	3	(25)
Inventories	(3)	—
Accounts payable and accrued expenses	(27)	5
Collateral (paid) received, net	(25)	1
Income taxes	8	1
Regulatory assets and liabilities, net	(3)	(7)
Pension and non-pension postretirement benefit contributions	(4)	(5)
Other assets and liabilities	11	(12)
Net cash flows provided by operating activities	<u>178</u>	<u>120</u>
Cash flows from investing activities		
Capital expenditures	(264)	(218)
Other investing activities	8	1
Net cash flows used in investing activities	<u>(256)</u>	<u>(217)</u>
Cash flows from financing activities		
Changes in short-term borrowings	(299)	(175)
Issuance of long-term debt	250	400
Dividends paid on common stock	(48)	(42)
Contributions from parent	243	387
Other financing activities	(14)	(5)
Net cash flows provided by financing activities	<u>132</u>	<u>565</u>
Increase in cash, restricted cash, and cash equivalents	<u>54</u>	<u>468</u>
Cash, restricted cash, and cash equivalents at beginning of period	<u>99</u>	<u>68</u>
Cash, restricted cash, and cash equivalents at end of period	<u>\$ 153</u>	<u>\$ 536</u>
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (43)	\$ (36)

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	ASSETS	March 31, 2023	December 31, 2022
Current assets			
Cash and cash equivalents		\$ 126	\$ 45
Restricted cash and cash equivalents		27	54
Accounts receivable			
Customer accounts receivable	312	351	
Customer allowance for credit losses	(49)	(47)	
Customer accounts receivable, net		263	304
Other accounts receivable	166	180	
Other allowance for credit losses	(28)	(25)	
Other accounts receivable, net		138	155
Receivables from affiliates		1	—
Inventories, net		138	135
Regulatory assets		248	235
Other		33	53
Total current assets		974	981
Property, plant, and equipment (net of accumulated depreciation and amortization of \$4,118 and \$4,067 as of March 31, 2023 and December 31, 2022, respectively)		8,955	8,794
Deferred debits and other assets			
Regulatory assets		424	437
Investments		121	119
Prepaid pension asset		266	273
Other		55	53
Total deferred debits and other assets		866	882
Total assets		\$ 10,795	\$ 10,657

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ —	\$ 299
Long-term debt due within one year	405	4
Accounts payable	311	382
Accrued expenses	131	125
Payables to affiliates	38	34
Customer deposits	41	39
Regulatory liabilities	5	6
Merger related obligation	25	26
Other	75	93
Total current liabilities	1,031	1,008
Long-term debt	3,590	3,747
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,398	1,382
Regulatory liabilities	435	455
Asset retirement obligations	39	39
Other	260	244
Total deferred credits and other liabilities	2,132	2,120
Total liabilities	6,753	6,875
Commitments and contingencies		
Shareholder's equity		
Common stock	3,010	2,767
Retained earnings	1,032	1,015
Total shareholder's equity	4,042	3,782
Total liabilities and shareholder's equity	\$ 10,795	\$ 10,657

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Three Months Ended March 31, 2023		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2022	\$ 2,767	\$ 1,015	\$ 3,782
Net income	—	65	65
Common stock dividends	—	(48)	(48)
Contributions from parent	243	—	243
Balance, March 31, 2023	<u>\$ 3,010</u>	<u>\$ 1,032</u>	<u>\$ 4,042</u>

(In millions)	Three Months Ended March 31, 2022		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2021	\$ 2,302	\$ 1,173	\$ 3,475
Net income	—	46	46
Common stock dividends	—	(42)	(42)
Contributions from parent	387	—	387
Balance, March 31, 2022	<u>\$ 2,689</u>	<u>\$ 1,177</u>	<u>\$ 3,866</u>

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Operating revenues		
Electric operating revenues	\$ 366	\$ 348
Natural gas operating revenues	97	83
Revenues from alternative revenue programs	9	(1)
Operating revenues from affiliates	2	1
Total operating revenues	<u>474</u>	<u>431</u>
Operating expenses		
Purchased power	166	137
Purchased fuel	55	42
Purchased power from affiliate	—	10
Operating and maintenance	46	51
Operating and maintenance from affiliates	41	42
Depreciation and amortization	60	57
Taxes other than income taxes	20	18
Total operating expenses	<u>388</u>	<u>357</u>
Operating income	<u>86</u>	<u>74</u>
Other income and (deductions)		
Interest expense, net	(17)	(16)
Other, net	3	2
Total other income and (deductions)	<u>(14)</u>	<u>(14)</u>
Income before income taxes	<u>72</u>	<u>60</u>
Income taxes	<u>12</u>	<u>4</u>
Net income	<u>\$ 60</u>	<u>\$ 56</u>
Comprehensive income	<u>\$ 60</u>	<u>\$ 56</u>

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Cash flows from operating activities		
Net income	\$ 60	\$ 56
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	60	57
Deferred income taxes and amortization of investment tax credits	3	5
Other non-cash operating activities	(1)	9
Changes in assets and liabilities:		
Accounts receivable	23	(17)
Receivables from and payables to affiliates, net	4	(17)
Inventories	10	8
Accounts payable and accrued expenses	(16)	15
Collateral (paid) received, net	(120)	30
Income taxes	9	(1)
Regulatory assets and liabilities, net	27	—
Pension and non-pension postretirement benefit contributions	—	(1)
Other assets and liabilities	1	3
Net cash flows provided by operating activities	60	147
Cash flows from investing activities		
Capital expenditures	(134)	(103)
Other investing activities	—	1
Net cash flows used in investing activities	(134)	(102)
Cash flows from financing activities		
Changes in short-term borrowings	(115)	(149)
Issuance of long-term debt	125	125
Dividends paid on common stock	(42)	(41)
Contributions from parent	99	144
Other financing activities	(2)	(2)
Net cash flows provided by financing activities	65	77
(Decrease) increase in cash, restricted cash, and cash equivalents	(9)	122
Cash, restricted cash, and cash equivalents at beginning of period	152	71
Cash, restricted cash, and cash equivalents at end of period	\$ 143	\$ 193
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (3)	\$ (8)

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	ASSETS	March 31, 2023	December 31, 2022
Current assets			
Cash and cash equivalents		\$ 142	\$ 31
Restricted cash and cash equivalents		1	121
Accounts receivable			
Customer accounts receivable	182	204	
Customer allowance for credit losses	(26)	(21)	
Customer accounts receivable, net		156	183
Other accounts receivable	48	52	
Other allowance for credit losses	(8)	(7)	
Other accounts receivable, net		40	45
Inventories, net			
Fossil fuel		5	18
Materials and supplies		61	58
Regulatory assets		63	80
Other		30	37
Total current assets		498	573
Property, plant, and equipment (net of accumulated depreciation and amortization of \$1,811 and \$1,772 as of March 31, 2023 and December 31, 2022, respectively)			
		4,902	4,820
Deferred debits and other assets			
Regulatory assets		202	202
Prepaid pension asset		148	153
Other		54	54
Total deferred debits and other assets		404	409
Total assets		\$ 5,804	\$ 5,802

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ —	\$ 115
Long-term debt due within one year	584	584
Accounts payable	148	172
Accrued expenses	51	41
Payables to affiliates	26	22
Customer deposits	30	29
Regulatory liabilities	49	44
Other	17	136
Total current liabilities	<u>905</u>	<u>1,143</u>
Long-term debt	<u>1,477</u>	<u>1,354</u>
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	882	869
Regulatory liabilities	374	380
Asset retirement obligations	13	13
Non-pension postretirement benefits obligations	9	9
Other	77	84
Total deferred credits and other liabilities	<u>1,355</u>	<u>1,355</u>
Total liabilities	<u>3,737</u>	<u>3,852</u>
Commitments and contingencies		
Shareholder's equity		
Common stock	1,455	1,356
Retained earnings	612	594
Total shareholder's equity	<u>2,067</u>	<u>1,950</u>
Total liabilities and shareholder's equity	<u>\$ 5,804</u>	<u>\$ 5,802</u>

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

<i>(In millions)</i>	Three Months Ended March 31, 2023		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2022	\$ 1,356	\$ 594	\$ 1,950
Net income	—	60	60
Common stock dividends	—	(42)	(42)
Contributions from parent	99	—	99
Balance, March 31, 2023	<u>\$ 1,455</u>	<u>\$ 612</u>	<u>\$ 2,067</u>

<i>(In millions)</i>	Three Months Ended March 31, 2022		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2021	\$ 1,209	\$ 568	\$ 1,777
Net income	—	56	56
Common stock dividends	—	(41)	(41)
Contributions from parent	144	—	144
Balance, March 31, 2022	<u>\$ 1,353</u>	<u>\$ 583</u>	<u>\$ 1,936</u>

See the Combined Notes to Consolidated Financial Statements

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Operating revenues		
Electric operating revenues	\$ 335	\$ 345
Revenues from alternative revenue programs	17	3
Operating revenues from affiliates	1	1
Total operating revenues	353	349
Operating expenses		
Purchased power	148	176
Purchased power from affiliate	—	2
Operating and maintenance	44	47
Operating and maintenance from affiliates	37	37
Depreciation and amortization	67	47
Taxes other than income taxes	2	2
Total operating expenses	298	311
Operating income	55	38
Other income and (deductions)		
Interest expense, net	(16)	(14)
Other, net	5	3
Total other income and (deductions)	(11)	(11)
Income before income taxes	44	27
Income taxes	11	1
Net income	\$ 33	\$ 26
Comprehensive income	\$ 33	\$ 26

See the Combined Notes to Consolidated Financial Statements

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2023	2022
Cash flows from operating activities		
Net income	\$ 33	\$ 26
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	67	47
Deferred income taxes and amortization of investment tax credits	6	1
Other non-cash operating activities	(9)	2
Changes in assets and liabilities:		
Accounts receivable	24	(1)
Receivables from and payables to affiliates, net	(1)	(6)
Inventories	(3)	(1)
Accounts payable and accrued expenses	(15)	(17)
Collateral paid, net	(44)	(3)
Income taxes	5	—
Regulatory assets and liabilities, net	3	(3)
Pension and non-pension postretirement benefit contributions	(1)	(7)
Other assets and liabilities	(21)	6
Net cash flows provided by operating activities	<u>44</u>	<u>44</u>
Cash flows from investing activities		
Capital expenditures	(161)	(87)
Net cash flows used in investing activities	<u>(161)</u>	<u>(87)</u>
Cash flows from financing activities		
Changes in short-term borrowings	—	(144)
Issuance of long-term debt	75	175
Dividends paid on common stock	(21)	(19)
Contributions from parent	63	173
Other financing activities	(1)	(3)
Net cash flows provided by financing activities	<u>116</u>	<u>182</u>
(Decrease) increase in cash and cash equivalents	<u>(1)</u>	<u>139</u>
Cash and cash equivalents at beginning of period	<u>72</u>	<u>29</u>
Cash and cash equivalents at end of period	<u>\$ 71</u>	<u>\$ 168</u>
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (30)	\$ (10)

See the Combined Notes to Consolidated Financial Statements

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2023	December 31, 2022
ASSETS		
Current assets		
Cash and cash equivalents	\$ 71	\$ 72
Accounts receivable		
Customer accounts receivable	156	179
Customer allowance for credit losses	(37)	(41)
Customer accounts receivable, net	119	138
Other accounts receivable	64	70
Other allowance for credit losses	(14)	(14)
Other accounts receivable, net	50	56
Receivables from affiliates	2	1
Inventories, net	46	43
Regulatory assets	114	130
Other	5	3
Total current assets	407	443
Property, plant, and equipment (net of accumulated depreciation and amortization of \$1,583 and \$1,551 as of March 31, 2023 and December 31, 2022, respectively)	4,067	3,990
Deferred debits and other assets		
Regulatory assets	492	494
Prepaid pension asset	14	18
Other	33	34
Total deferred debits and other assets	539	546
Total assets	\$ 5,013	\$ 4,979

See the Combined Notes to Consolidated Financial Statements

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	\$ 3	\$ 3
Accounts payable	167	206
Accrued expenses	46	47
Payables to affiliates	26	26
Customer deposits	21	21
Regulatory liabilities	15	26
PPA termination obligation	87	87
Other	12	58
Total current liabilities	377	474
Long-term debt	1,828	1,754
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	742	734
Regulatory liabilities	148	156
Non-pension postretirement benefit obligations	7	8
Other	83	100
Total deferred credits and other liabilities	980	998
Total liabilities	3,185	3,226
Commitments and contingencies		
Shareholder's equity		
Common stock	1,828	1,765
Retained earnings (deficit)	—	(12)
Total shareholder's equity	1,828	1,753
Total liabilities and shareholder's equity	\$ 5,013	\$ 4,979

See the Combined Notes to Consolidated Financial Statements

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

<i>(In millions)</i>	Three Months Ended March 31, 2023		
	Common Stock	Retained (Deficit) Earnings	Total Shareholder's Equity
Balance, December 31, 2022	\$ 1,765	\$ (12)	\$ 1,753
Net income	—	33	33
Common stock dividends	—	(21)	(21)
Contributions from parent	63	—	63
Balance, March 31, 2023	<u>\$ 1,828</u>	<u>\$ —</u>	<u>\$ 1,828</u>

<i>(In millions)</i>	Three Months Ended March 31, 2022		
	Common Stock	Retained Deficit	Total Shareholder's Equity
Balance, December 31, 2021	\$ 1,590	\$ (15)	\$ 1,575
Net income	—	26	26
Common stock dividends	—	(19)	(19)
Contributions from parent	173	—	173
Balance, March 31, 2022	<u>\$ 1,763</u>	<u>\$ (8)</u>	<u>\$ 1,755</u>

See the Combined Notes to Consolidated Financial Statements

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in millions, except per share data, unless otherwise noted)

1. Significant Accounting Policies (All Registrants)

Description of Business

Exelon is a utility services holding company engaged in the energy transmission and distribution businesses through ComEd, PECO, BGE, Pepco, DPL, and ACE.

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation. The separation was completed on February 1, 2022, creating two publicly traded companies, Exelon and Constellation. See Note 2 — Discontinued Operations for additional information.

Name of Registrant	Business	Service Territories
Commonwealth Edison Company	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Northern Illinois, including the City of Chicago
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Southeastern Pennsylvania, including the City of Philadelphia (electricity) Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Central Maryland, including the City of Baltimore (electricity and natural gas)
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 Transmission and distribution of electricity to retail customers	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of Delaware and Maryland (electricity) Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Portions of Southern New Jersey

Basis of Presentation

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, except for the historical transactions between the Utility Registrants and Generation for the purposes of presenting discontinued operations in all periods presented in the Consolidated Statements of Operations and Comprehensive Income.

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, distribution and transmission planning, asset management, system operations, and power procurement, to PHI operating companies. 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" in the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in millions, except per share data, unless otherwise noted)

Note 1 — Significant Accounting Policies

The accompanying consolidated financial statements as of March 31, 2023 and for the three months ended March 31, 2023 and 2022 are unaudited but, in the opinion of the management of each Registrant 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, 2022 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, 2023. 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.

The separation of Constellation, including Generation and its subsidiaries, met the criteria for discontinued operations and as such, results of operations are presented as discontinued operations and have been excluded from continuing operations for all periods presented. Accounting rules require that certain BSC costs previously allocated to Generation be presented as part of Exelon's continuing operations as these costs do not qualify as expenses of the discontinued operations. Comprehensive income, shareholders' equity, and cash flows related to Constellation have not been segregated and are included in the Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Changes in Shareholders' Equity, and Consolidated Statements of Cash Flows, respectively, for the three months ended March 31, 2022. See Note 2 — Discontinued Operations for additional information.

2. Discontinued Operations (Exelon)

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies ("the separation"). Exelon completed the separation on February 1, 2022. Constellation was newly formed and incorporated in Pennsylvania on June 15, 2021 for the purposes of separation and holds Generation (including Generation's subsidiaries). Pursuant to the separation, Exelon contributed its equity ownership interest in Generation to Constellation. Exelon no longer retains any equity ownership interest in Generation or Constellation. See Note 2 — Discontinued Operations of the 2022 Form 10-K for additional information.

Continuing Involvement

In order to govern the ongoing relationships between Exelon and Constellation after the separation, and to facilitate an orderly transition, Exelon and Constellation have entered into several agreements, including the following:

- Separation Agreement – governs the rights and obligations between Exelon and Constellation regarding certain actions to be taken in connection with the separation, among others, including the allocation of assets and liabilities between Exelon and Constellation.
- Transition Services Agreement (TSA) – governs the terms and conditions of the services that Exelon will provide to Constellation and Constellation will provide to Exelon for an expected period of two years, provided that certain services may be longer than the term and services may be extended with approval from both parties. The services include specified accounting, finance, information technology, human resources, employee benefits and other services that have historically been provided on a centralized basis by BSC. For the three months ended March 31, 2023, the amounts Exelon billed Constellation and Constellation billed Exelon for these services were \$50 million recorded in Other income, net and \$6 million recorded in Operating and maintenance expense, respectively. For the period from February 1, 2022 to March 31, 2022, the amounts Exelon billed Constellation and Constellation billed Exelon for these services were \$56 million recorded in Other income, net and \$9 million recorded in Operating and maintenance expense, respectively.
- Tax Matters Agreement (TMA) – governs the respective rights, responsibilities and obligations of Exelon and Constellation with respect to all tax matters, including tax liabilities and benefits, tax attributes, tax returns, tax contests and other tax sharing regarding U.S. federal, state, local and foreign income taxes, other tax matters and related tax returns. See Note 7 — Income Taxes for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 2 — Discontinued Operations

In addition, the Utility Registrants will continue to incur expenses from transactions with Constellation after the separation. Prior to the separation, such expenses were primarily recorded as Purchased power from affiliates and an immaterial amount recorded as Operating and maintenance expense from affiliates at the Utility Registrants. After the separation, such expenses are primarily recorded as Purchased power and an immaterial amount recorded as Operating and maintenance expense at the Utility Registrants.

- ComEd had an ICC-approved RFP contract with Constellation to provide a portion of ComEd's electric supply requirements. ComEd also purchased RECs and ZECs from Constellation.
- PECO received electric supply from Constellation under contracts executed through PECO's competitive procurement process. In addition, PECO had a ten-year agreement with Constellation to sell solar AECs.
- BGE received a portion of its energy requirements from Constellation under its MDPSC-approved market-based SOS and gas commodity programs.
- Pepco received electric supply from Constellation under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.
- DPL received a portion of its energy requirements from Constellation under its MDPSC and DEPSC approved market-based SOS commodity programs.
- ACE received electric supply from Constellation under contracts executed through ACE's competitive procurement process approved by the NJBPU.

ComEd and PECO also have receivables with Constellation for estimated excess funds at the end of decommissioning the Regulatory Agreement Units, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 3 — Regulatory Matters and Note 23 — Related Party Transactions of the 2022 Form 10-K for additional information.

Discontinued Operations

The separation represented a strategic shift that would have a major effect on Exelon's operations and financial results. Accordingly, the separation meets the criteria for discontinued operations.

There were no results from discontinued operations for the three months ended March 31, 2023. The following table presents the results of Constellation that have been reclassified from continuing operations and included in discontinued operations within Exelon's Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2022.

These results are primarily Generation, which is comprised of Exelon's Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions reportable segments, and include the impact of transaction costs, certain BSC costs, including any transition costs, that were historically allocated and directly attributable to Generation, transactions between Generation and the Utility Registrants, and tax-related adjustments. Transaction costs include costs for external bankers, accountants, appraisers, lawyers, external counsels and other advisors, among others, who are involved in the negotiation, appraisal, due diligence and regulatory approval of the separation. Transition costs are primarily employee-related costs such as recruitment expenses, costs to establish certain stand-alone functions and information technology systems, professional services fees and other separation-related costs during the transition to separate Generation. For the purposes of reporting discontinued operations, these results also include transactions between Generation and the Utility Registrants that were historically eliminated within Exelon's Consolidated Statements of Operations as these transactions will be ongoing after the separation. Certain BSC costs that were historically allocated to Generation are presented as part of continuing operations in Exelon's Consolidated Statements of Operations as these costs do not qualify as expenses of the discontinued operations per the accounting rules.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 2 — Discontinued Operations

	Three Months Ended March 31, 2022
Operating revenues	
Competitive business revenues	\$ 1,855
Competitive business revenues from affiliates	161
Total operating revenues	2,016
Operating expenses	
Competitive businesses purchased power and fuel	1,138
Operating and maintenance ^(a)	371
Depreciation and amortization	94
Taxes other than income taxes	44
Total operating expenses	1,647
Gain on sales of assets and businesses	10
Operating income	379
Other income and (deductions)	
Interest expense, net	(20)
Other, net	(281)
Total other (deductions) and income	(301)
Income before income taxes	78
Income taxes	(40)
Equity in losses of unconsolidated affiliates	(1)
Net income	117
Net income attributable to noncontrolling interests	1
Net income from discontinued operations	\$ 116

(a) Includes transaction and transition costs related to the separation of \$52 million for the three months ended March 31, 2022.

There were no assets or liabilities of discontinued operations included in Exelon's Consolidated Balance Sheet as of March 31, 2023 and December 31, 2022. Constellation had net assets of \$11,573 million that separated on February 1, 2022 that resulted in a reduction to Exelon's equity during the year ended December 31, 2022. Refer to the Distribution of Constellation line in Exelon's Consolidated Statement of Changes in Shareholders' Equity for further information.

There were no discontinued operations included within Exelon's Consolidated Statements of Cash Flows for the three months ended March 31, 2023. The following table presents selected financial information regarding cash flows of the discontinued operations that are included within Exelon's Consolidated Statements of Cash Flows for the three months ended March 31, 2022.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 2 — Discontinued Operations

	Three Months Ended March 31, 2022
Non-cash items included in net income from discontinued operations:	
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	\$ 207
Loss on sales of assets and businesses	9
Deferred income taxes and amortization of investment tax credits	(143)
Net fair value changes related to derivatives	(59)
Net realized and unrealized losses on NDT fund investments	205
Net unrealized losses on equity investments	16
Other decommissioning-related activity	36
Cash flows from investing activities:	
Capital expenditures	(227)
Collection of DPP	169
Supplemental cash flow information:	
Decrease in capital expenditures not paid	(128)
Increase in DPP	348
Increase in PP&E related to ARO update	335

3. Regulatory Matters (All Registrants)

As discussed in Note 3 — Regulatory Matters of the 2022 Form 10-K, the Registrants are involved in rate and regulatory proceedings at FERC and their state commissions. The following discusses developments in 2023 and updates to the 2022 Form 10-K.

Distribution Base Rate Case Proceedings

The following tables show the completed and pending distribution base rate case proceedings in 2023.

Completed Distribution Base Rate Case Proceedings

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 3 — Regulatory Matters

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois ^(a)	April 15, 2022	Electric	\$ 199	\$ 199	7.85 %	November 17, 2022	January 1, 2023
PECO - Pennsylvania	March 31, 2022	Natural Gas	82	55	N/A ^(b)	October 27, 2022	January 1, 2023
BGE - Maryland ^(c)	May 15, 2020 (amended September 11, 2020)	Electric	203	140	9.50 %	December 16, 2020	January 1, 2021
		Natural Gas	108	74	9.65 %		
Pepco - Maryland ^(d)	October 26, 2020 (amended March 31, 2021)	Electric	104	52	9.55 %	June 28, 2021	June 28, 2021
DPL - Maryland ^(e)	May 19, 2022	Electric	38	29	9.60 %	December 14, 2022	January 1, 2023

- (a) ComEd's 2023 approved revenue requirement above reflects an increase of \$144 million for the initial year revenue requirement for 2023 and an increase of \$55 million related to the annual reconciliation for 2021. The revenue requirement for 2023 provides for a weighted average debt and equity return on distribution rate base of 5.94%, inclusive of an allowed ROE of 7.85%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points. The reconciliation revenue requirement for 2021 provides for a weighted average debt and equity return on distribution rate base of 5.91%, inclusive of an allowed ROE of 7.78%, reflecting the monthly yields on 30-year treasury bonds plus 580 basis points less a performance metrics penalty of 7 basis points. This is ComEd's last performance-based electric distribution formula rate update filing under EIMA. See discussion of CEJA below for details on the transition away from the electric distribution formula rate.
- (b) The PECO natural gas base rate case proceeding was resolved through a settlement agreement, which did not specify an approved ROE.
- (c) Reflects a three-year cumulative multi-year plan for 2021 through 2023. BGE proposed to use certain tax benefits to fully offset the increases in 2021 and 2022 and partially offset the increase in 2023. The MDPSC awarded BGE electric revenue requirement increases of \$59 million, \$39 million, and \$42 million, before offsets, in 2021, 2022, and 2023, respectively, and natural gas revenue requirement increases of \$53 million, \$11 million, and \$10 million, before offsets, in 2021, 2022, and 2023, respectively. However, the MDPSC utilized the tax benefits to fully offset the increases in 2021 and January 2022 such that customer rates remained unchanged. For the remainder of 2022, the MDPSC chose to offset only 25% of the cumulative 2021 and 2022 electric revenue requirement increases and 50% of the cumulative gas revenue requirement increases. In 2021, the MDPSC deferred a decision on whether to use certain tax benefits to offset the revenue requirement increases in 2023 and directed BGE to make another proposal at the end of 2022. In September 2022 BGE proposed that tax benefits not be used to offset the 2023 revenue requirement increases. On October 26, 2022, the MDPSC accepted BGE's recommendation to not use tax benefits to offset the 2023 revenue requirement increases.
- (d) Reflects a three-year cumulative multi-year plan for April 1, 2021 through March 31, 2024. The MDPSC awarded Pepco electric incremental revenue requirement increases of \$21 million, \$16 million, and \$15 million, before offsets, for the 12-month periods ending March 31, 2022, 2023, and 2024, respectively. Pepco proposed to utilize certain tax benefits to fully offset the increase through 2023 and partially offset customer rate increases in 2024. However, the MDPSC only utilized the acceleration of refunds for certain tax benefits to fully offset the increases such that customer rates remain unchanged through March 31, 2022. On February 23, 2022, the MDPSC chose to offset 25% of the cumulative revenue requirement increase for the 12-month period ending March 31, 2023. Whether certain tax benefits will be used to offset the customer rate increases for the 12-month period ending March 31, 2024 has not been decided, and Pepco cannot predict the outcome.
- (e) 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 3 — Regulatory Matters

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois ^(a)	January 17, 2023	Electric	\$ 1,472	10.50% to 10.65%	Fourth quarter of 2023
ComEd - Illinois ^(b)	April 21, 2023	Electric	247	8.91%	Fourth quarter of 2023
BGE - Maryland ^(c)	February 17, 2023	Electric	313	10.40%	Fourth quarter of 2023
		Natural Gas	289	10.40%	
Pepco - District of Columbia ^(d)	April 13, 2023	Electric	191	10.50%	First quarter of 2024
DPL - Delaware ^(e)	December 15, 2022 (amended February 28, 2023)	Electric	48	10.50%	Second quarter of 2024
ACE - New Jersey ^(f)	February 15, 2023	Electric	105	10.50%	First quarter of 2024

- (a) Reflects a four-year cumulative MRP for January 1, 2024 to December 31, 2027 and total requested revenue requirement increases of \$877 million effective January 1, 2024, \$175 million effective January 1, 2025, \$217 million effective January 1, 2026, and \$203 million effective January 1, 2027, based on forecasted revenue requirements. The revenue requirement will provide for a weighted average debt and equity return on distribution rate base of 7.43% in 2024, 7.50% in 2025, 7.62% in 2026, and 7.70% in 2027, inclusive of an allowed ROE of 10.50% in 2024, 10.55% in 2025, 10.60% in 2026, and 10.65% in 2027. The requested revenue requirements are based on capital structures that reflect between 50.58% and 51.19% common equity. ComEd's MRP also includes a proposed rate phase-in to defer approximately \$307 million of the \$877 million year-over-year increase for 2024 revenue from 2024 to 2026.
- (b) On April 21, 2023, ComEd filed its proposed Delivery Reconciliation Amount of \$247 million under Rider Delivery Service Pricing Reconciliation (Rider DSPR) which 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 2023 filing reconciles the delivery service rates in effect in 2022 with the actual delivery service costs incurred in 2022. Final order is expected by December 2023, and the reconciliation amount will be in customer rates beginning January 1, 2024.
- (c) Reflects a three-year cumulative multi-year plan for January 1, 2024 through December 31, 2026 submitted to the MDPSC. Inclusive of the proposed acceleration of remaining electric tax benefits in 2024 and 2025, and remaining gas tax benefits in 2024, BGE requested total electric revenue requirement increases of \$85 million, \$103 million, and \$125 million in 2024, 2025, and 2026, respectively, and natural gas revenue requirement increases of \$158 million, \$77 million, and \$54 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 2021 and 2022 reconciliation amounts are not included in the requested revenue requirement increase, as BGE is proposing that these amounts be recovered through the separate electric and gas riders in 2024. The 2021 reconciliation amounts are \$11 million and \$7 million for electric and gas, respectively, and the 2022 reconciliation amounts are \$44 million and \$15 million for electric and gas, respectively.
- (d) Reflects a three-year cumulative multi-year plan for January 1, 2024 through December 31, 2026 submitted to the DCPSC. Pepco requested total electric revenue requirement increases of \$117 million, \$37 million, and \$37 million in 2024, 2025, and 2026, respectively. Requested revenue requirement increases will be used to recover capital investments designed to advance system-readiness and support the District of Columbia's climate and clean energy goals.
- (e) The rates will go into effect on July 15, 2023, subject to refund.
- (f) Requested increases are before New Jersey sales and use tax. ACE intends to put rates into effect on November 17, 2023, subject to refund.

Transmission Formula Rates

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

taxes. The update for BGE also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2023, the following increases/(decreases) were included in BGE's annual electric transmission formula rate updates. ComEd, PECO, Pepco, DPL, and ACE intend to file by the required deadline for the annual update.

Registrant ^(a)	Initial Revenue Requirement Increase	Annual Reconciliation Decrease	Total Revenue Requirement Increase	Allowed Return on Rate Base ^(b)	Allowed ROE ^(c)
BGE	\$ 19	\$ (12)	\$ 4 ^(d)	7.34 %	10.50 %

(a) All rates are effective June 1, 2023 - May 31, 2024, subject to review by interested parties pursuant to review protocols of tariffs.

(b) Represents the weighted average debt and equity return on transmission rate bases.

(c) The rate of return on common equity includes a 50-basis-point incentive adder for being a member of a RTO.

(d) The increase in BGE's transmission revenue requirement includes a \$3 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) an extension of and certain adjustments to ComEd's energy efficiency MWh savings goals, (4) revisions to the Illinois RPS requirements, including expanded charges for the procurement of RECs from wind and solar generation, (5) a requirement to accelerate amortization of ComEd's unprotected excess deferred income taxes (EDIT) that ComEd was previously directed by the ICC to amortize using the average rate assumption method which equates to approximately 39.5 years, and (6) requirements that ComEd and the ICC initiate and conduct various regulatory proceedings on subjects including ethics, spending, grid investments, and performance metrics. Regulatory or legal challenges regarding the validity or implementation of CEJA are possible and Exelon and ComEd cannot reasonably predict the outcome of any such challenges.

ComEd Electric Distribution Rates

ComEd filed, and received approval for, its last performance-based electric distribution formula rate update filing under EIMA in 2022; those rates are in effect throughout 2023.

On February 3, 2022, the ICC approved a tariff that establishes the process under which ComEd will reconcile its 2022 and 2023 rate year revenue requirements with actual costs. Those reconciliation amounts will be determined using the same process as were used for prior reconciliations under the performance-based electric distribution formula rate. Using that process, for the rate years 2022 and 2023 ComEd will ultimately collect revenues from customers reflecting each year's actual recoverable costs, year-end rate base, and a weighted average debt and equity return on distribution rate base, with the ROE component based on the annual average of the monthly yields of the 30-year U.S. Treasury bonds plus 580 basis points. In April 2023, ComEd filed its first petition with the ICC to reconcile its 2022 actual costs with the approved revenue requirement that was in effect in 2022. The rate year 2023 reconciliation will be filed in 2024.

Beginning in 2024, ComEd will recover 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 3 — Regulatory Matters

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. The ICC must issue its decision on both the MRP and Grid Plan by mid-December 2023, for rates to begin with the January 2024 billing cycle.

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, 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. ComEd is determining how to implement the performance metrics, which take effect on January 1, 2024. ComEd will make its initial filing in 2025 to assess performance achieved under the metrics in 2024, and to determine any ROE adjustment, which would take effect in 2026.

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-powered 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 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. ComEd began issuing credits to its retail customers under its new CMC rider in the June 2022 billing period and recorded a regulatory asset of \$1,118 million as of March 31, 2023 for the difference between customer credits issued and the credit to be received from the participating nuclear-powered generating facilities.

Under CEJA, the costs of procuring CMCs, including carrying costs, will be recovered through a rider, the Rider Carbon-Free Resource Adjustment (Rider CFRA). The Rider CFRA provides for an annual reconciliation and true-up to actual costs incurred or credits received by ComEd to purchase CMCs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods. The difference between the net payments to (or receivables from) ComEd ratepayers and the credits received by ComEd to purchase CMCs is recorded to Purchased Power expense with an offset to the regulatory asset (or regulatory liability). On December 21, 2022, ComEd filed a supplemental statement to the Rider CFRA proposing that the company recover costs or provide credits faster than the tariff allows, implement monthly reconciliations, and allow the Company to adjust Rider CFRA rates based not only on anticipated differences but also past payments or credits. The ICC approved the proposal on January 19, 2023.

Beneficial Electrification Plan

On July 1, 2022, ComEd filed a proposed plan to promote beneficial electrification efforts in its Northern Illinois service area with the ICC as required by CEJA. ComEd's plan is designed to meaningfully reduce barriers to beneficial electrification, including those related to electric vehicles (EV), such as upfront technology adoption costs, charging costs, and charging availability; promote equity and environmental justice; reduce carbon emissions and surface-level pollutants; and support customer education and awareness of electrification options. As proposed, ComEd could expend approximately \$300 million in total over the three-year period 2023 through 2025. The beneficial electrification plan requests recovery of all those costs through a rider mechanism, under which certain of the costs would be amortized over ten years with a return on the unrecovered balance. On November 10, 2022, in responses to a Staff motion, the ICC approved an interim order dismissing from ComEd's Beneficial Electrification Plan certain rebates (rebates to support residential customers' purchase of EVs; and rebates to ComEd's commercial and industrial customers to support the installation of EV chargers). However, the ICC found that building electrification measures were properly within the scope of beneficial electrification, in line with ComEd's proposal. The ICC also adopted ComEd's position regarding the rate impact of spending associated with EV related infrastructure. On November 21, 2022, ComEd filed an application for rehearing of the interim order, which the ICC denied. On December 9, 2022, the Office of the Illinois Attorney General (AG) also

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 3 — Regulatory Matters

sought rehearing. On December 15, 2022, ComEd filed an appeal of the ICC's interim order and the denial of rehearing with the Illinois Appellate Court. That appeal has been stayed pending the ICC's disposition of the case. Also on December 15, 2022, the ICC denied the AG's application for rehearing and the AG subsequently filed an appeal.

On March 23, 2023, the ICC issued its final order in the beneficial electrification plan docket. The order adopts the beneficial electrification plan with modifications and directs ComEd to seek cost recovery through the multi-year rate plan filing for 2024 and 2025, and the final formula rate reconciliation docket for 2023, rather than through a new rider beneficial electrification as ComEd had proposed. The order also rejects ComEd's request for a regulatory asset. The order approves an overall annual budget of \$77 million per year for each of the three years in the plan (2023 through 2025), with flexibility to roll forward unused funds to future years within the same plan period. The final order also made specific reductions to the proposed \$100 million per year budget, reducing the proposed customer education and awareness budget; the portfolio budget for cross-cutting administrative support; and the light, medium, and heavy-duty EV rebate programs. The order dedicates funds for rebates related to the installation of heat pumps and the promotion of home electrification for low-income customers and those in Environmental Justice and Restore, Reinvest, and Renew designated communities. The order also requires ComEd to propose methods to minimize or exempt low-income ratepayers from the impact of its beneficial electrification plan, possibly through ComEd's next rate design investigation. On April 18, 2023, ComEd filed an application for rehearing concerning aspects of the ICC's order, including the approved budgets. The ICC must act on that application by May 8, 2023. On April 21, 2023, the Chicago Transit Authority and city of Chicago jointly filed an application for rehearing requesting the ICC modify the final order so the transit agencies do not pay the cost of make-ready infrastructure and to exempt transit agencies from paying the required deposit or providing a letter of credit to ComEd for the cost of make-ready infrastructure. On April 24, 2023, the AG also filed an application for rehearing on several topics, including the budget, rebate levels, retail rate cap, types of programs included in the beneficial electrification plan, compliance with the EV Act, benefit-to-cost analysis, and rate-related issues. On April 27, 2023, ICC staff filed a motion for clarification of the order's language regarding the annual budget. The ICC will likely rule on all of the applications for rehearing and staff's motion at their regularly scheduled May 4, 2023 regular open meeting. If the ICC denies rehearing, parties have 35 days to appeal arguments raised in their rehearing applications.

New Jersey Regulatory Matters

Termination of Energy Procurement Provisions of PPAs (Exelon, PHI, and ACE).

On December 22, 2021, ACE filed with the NJBPU a petition to terminate the provisions in the PPAs to purchase electricity from two coal-powered generation facilities located in the state of New Jersey. The petition was approved by the NJBPU on March 23, 2022. Upon closing of the transaction on March 31, 2022, ACE recognized a liability of \$203 million for the contract termination fee, which is to be paid by the end of 2024, and recognized a corresponding regulatory asset of \$203 million.

As of March 31, 2023, the \$118 million liability for the contract termination fee consists of \$87 million and \$31 million included in Other current liabilities and Other deferred credits and other liabilities, respectively, in Exelon's Consolidated Balance Sheet. The current and noncurrent liabilities are included in PPA termination obligation and Other deferred credits and other liabilities, respectively, in PHI's and ACE's Consolidated Balance Sheets. For the three months ended March 31, 2023, ACE has paid \$19 million of the liability, which is recorded in Changes in Other assets and liabilities in Exelon's, PHI's, and ACE's Consolidated Statements of Cash Flows.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 3 — Regulatory Matters

Other Federal Regulatory Matters

FERC Audit (Exelon and ComEd). The Utility Registrants are subject to periodic audits by FERC. FERC's Division of Audits and Accounting initiated a nonpublic audit of ComEd in May 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 covered the period from January 1, 2017 through August 31, 2022. On January 17 and February 21, 2023, ComEd was provided with information on a series of potential findings, including concerning ComEd's methodology regarding the allocation of certain overhead costs to capital under FERC regulations. As of March 31, 2023, ComEd has continued discussions with FERC staff and determined that a loss is probable and has recorded a liability that reflects management's best estimate. The final outcome and resolution of the findings or of the audit itself cannot be predicted and the results could be material to the Exelon and ComEd financial statements.

Regulatory Assets and Liabilities

The Utility Registrants' regulatory assets and liabilities have not changed materially since December 31, 2022, unless noted below. See Note 3 — Regulatory Matters of the 2022 Form 10-K for additional information on the specific regulatory assets and liabilities.

ComEd. Regulatory assets increased \$547 million primarily due to increases of \$275 million in the CMC regulatory asset, as discussed in CEJA above, and \$143 million in the Electric Distribution Formula Rate Annual Reconciliations regulatory asset.

PECO. Regulatory assets increased \$44 million primarily due to an increase of \$48 million in the Deferred Income Taxes regulatory asset. Regulatory liabilities increased \$45 million primarily due to increases of \$31 million in the Electric Energy and Natural Gas Costs regulatory liability and \$28 million in the Decommissioning the Regulatory Agreement Units regulatory liability.

BGE. Regulatory assets increased \$66 million primarily due to an increase of \$54 million in the Under-Recovered Revenue Decoupling regulatory asset.

DPL. Regulatory assets decreased \$17 million primarily due to a decrease of \$18 million in the Electric Energy and Natural Gas Costs regulatory asset.

ACE. Regulatory assets decreased \$18 million primarily due to a decrease of \$35 million in the Electric Energy Costs regulatory asset as a result of the PPA termination. Regulatory liabilities decreased \$19 million primarily due to a \$9 million decrease in the Over-Recovered Revenue Decoupling 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 as of March 31, 2023 and December 31, 2022.

	Exelon	ComEd ^(a)	BGE ^(b)	PHI	Pepco ^(c)	DPL ^(c)	ACE ^(b)
March 31, 2023	\$ 53	\$ 13	\$ 26	\$ 14	\$ 11	\$ 2	\$ 1
December 31, 2022	57	8	28	21	18	2	1

(a) Reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its electric distribution formula rate regulatory assets.

(b) BGE's and ACE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholder's investment on their respective AMI programs.

(c) Pepco's and DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholder's investment on their respective AMI Programs and Energy Efficiency and Demand Response Programs, and for Pepco District of Columbia revenue decoupling program. The earnings on energy efficiency are on Pepco District of Columbia and DPL Delaware programs only.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 4 — Revenue from Contracts with Customers

4. 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 2022 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 PHI, Pepco, DPL, and ACE these contract liabilities primarily relate to upfront consideration received in the third quarter of 2020 for a collaborative arrangement with an unrelated owner and manager of communication infrastructure. The revenue attributable to this arrangement will be recognized as operating revenue over the 35 years under the collaborative arrangement.

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, 2023 and 2022. As of March 31, 2023 and December 31, 2022, ComEd's, PECO's, and BGE's contract liabilities were immaterial.

	Exelon ^(a)	PHI ^(a)	Pepco ^(a)	DPL	ACE
Balance as of December 31, 2022	\$ 101	\$ 101	\$ 81	\$ 10	\$ 10
Revenues recognized	(1)	(1)	(1)	—	—
Balance as of March 31, 2023	<u>\$ 100</u>	<u>\$ 100</u>	<u>\$ 80</u>	<u>\$ 10</u>	<u>\$ 10</u>
	Exelon ^(a)	PHI ^(a)	Pepco ^(a)	DPL	ACE
Balance as of December 31, 2021	\$ 109	\$ 109	\$ 87	\$ 11	\$ 11
Revenues recognized	(2)	(2)	(2)	—	—
Balance as of March 31, 2022	<u>\$ 107</u>	<u>\$ 107</u>	<u>\$ 85</u>	<u>\$ 11</u>	<u>\$ 11</u>

(a) Revenues recognized in the three months ended March 31, 2023 and 2022, were included in the contract liabilities at December 31, 2022 and 2021, 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, 2023. 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.

Year	Exelon	PHI	Pepco	DPL	ACE
2023	\$ 7	\$ 7	\$ 5	\$ 1	\$ 1
2024	6	6	5	—	1
2025	5	5	5	—	—
2026	5	5	5	—	—
2027 and thereafter	77	77	60	9	8
Total	<u>\$ 100</u>	<u>\$ 100</u>	<u>\$ 80</u>	<u>\$ 10</u>	<u>\$ 10</u>

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 4 — Revenue from Contracts with Customers

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 5 — Segment Information for the presentation of the Registrants' revenue disaggregation.

5. 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.

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, Pepco, DPL, and ACE's CODMs evaluate the performance of and allocate resources to the segments based on net income.

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, 2023 and 2022 is as follows:

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 5 — Segment Information

	ComEd	PECO	BGE	PHI	Other ^(a)	Intersegment Eliminations	Exelon
Operating revenues^(b):							
2023							
Electric revenues	\$ 1,667	\$ 795	\$ 814	\$ 1,436	\$ —	\$ (5)	\$ 4,707
Natural gas revenues	—	317	443	97	—	(1)	856
Shared service and other revenues	—	—	—	3	437	(440)	—
Total operating revenues	<u>\$ 1,667</u>	<u>\$ 1,112</u>	<u>\$ 1,257</u>	<u>\$ 1,536</u>	<u>\$ 437</u>	<u>\$ (446)</u>	<u>\$ 5,563</u>
2022							
Electric revenues	\$ 1,734	\$ 741	\$ 736	\$ 1,318	\$ —	\$ (7)	\$ 4,522
Natural gas revenues	—	306	418	83	—	(2)	805
Shared service and other revenues	—	—	—	3	576	(579)	—
Total operating revenues	<u>\$ 1,734</u>	<u>\$ 1,047</u>	<u>\$ 1,154</u>	<u>\$ 1,404</u>	<u>\$ 576</u>	<u>\$ (588)</u>	<u>\$ 5,327</u>
Intersegment revenues^(c):							
2023	\$ 3	\$ 2	\$ 3	\$ 3	\$ 434	\$ (445)	\$ —
2022	6	1	7	3	576	(587)	6
Depreciation and amortization:							
2023	\$ 338	\$ 98	\$ 167	\$ 241	\$ 16	\$ —	\$ 860
2022	321	92	171	218	15	—	817
Operating expenses:							
2023	\$ 1,256	\$ 902	\$ 964	\$ 1,297	\$ 485	\$ (447)	\$ 4,457
2022	1,406	793	919	1,215	625	(531)	4,427
Interest expense, net:							
2023	\$ 117	\$ 48	\$ 44	\$ 76	\$ 127	\$ —	\$ 412
2022	100	41	35	69	93	—	338
Income (loss) from continuing operations before income taxes:							
2023	\$ 312	\$ 170	\$ 252	\$ 189	\$ (120)	\$ —	\$ 803
2022	240	220	207	137	(62)	(43)	699
Income taxes:							
2023	\$ 71	\$ 4	\$ 52	\$ 34	\$ (27)	\$ —	\$ 134
2022	52	14	9	7	146	(10)	218
Net income (loss) from continuing operations:							
2023	\$ 241	\$ 166	\$ 200	\$ 155	\$ (93)	\$ —	\$ 669
2022	188	206	198	130	(208)	(33)	481
Capital expenditures:							
2023	\$ 617	\$ 335	\$ 350	\$ 561	\$ 18	\$ —	\$ 1,881
2022	617	344	303	409	22	—	1,695
Total assets:							
March 31, 2023	\$ 40,720	\$ 14,738	\$ 13,411	\$ 26,208	\$ 6,042	\$ (4,194)	\$ 96,925
December 31, 2022	39,661	14,502	13,350	26,082	6,014	(4,260)	95,349

(a) Other primarily includes Exelon's corporate operations, shared service entities, and other financing and investment activities.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 5 — Segment Information

- (b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 15 — Supplemental Financial Information for additional information on total utility taxes.
(c) See Note 16 — Related Party Transactions for additional information on intersegment revenues.

PHI:

	Pepco	DPL	ACE	Other ^(a)	Intersegment Eliminations	PHI
Operating revenues^(b):						
2023						
Electric revenues	\$ 710	\$ 377	\$ 353	\$ —	\$ (4)	\$ 1,436
Natural gas revenues	—	97	—	—	—	97
Shared service and other revenues	—	—	—	102	(99)	3
Total operating revenues	\$ 710	\$ 474	\$ 353	\$ 102	\$ (103)	\$ 1,536
2022						
Electric revenues	\$ 614	\$ 348	\$ 349	\$ —	\$ 7	\$ 1,318
Natural gas revenues	—	83	—	—	—	83
Shared service and other revenues	—	—	—	107	(104)	3
Total operating revenues	\$ 614	\$ 431	\$ 349	\$ 107	\$ (97)	\$ 1,404
Intersegment revenues^(c):						
2023	\$ 1	\$ 2	\$ 1	\$ 102	\$ (103)	\$ 3
2022	1	1	1	97	(97)	3
Depreciation and amortization:						
2023	\$ 108	\$ 60	\$ 67	\$ 6	\$ —	\$ 241
2022	108	57	47	6	—	218
Operating expenses:						
2023	\$ 610	\$ 388	\$ 298	\$ 104	\$ (103)	\$ 1,297
2022	547	357	311	97	(97)	1,215
Interest expense, net:						
2023	\$ 39	\$ 17	\$ 16	\$ 4	\$ —	\$ 76
2022	36	16	14	3	—	69
Income (loss) before income taxes:						
2023	\$ 77	\$ 72	\$ 44	\$ (4)	\$ —	\$ 189
2022	44	60	27	6	—	137
Income taxes:						
2023	\$ 12	\$ 12	\$ 11	\$ (1)	\$ —	\$ 34
2022	(2)	4	1	4	—	7
Net income (loss):						
2023	\$ 65	\$ 60	\$ 33	\$ (3)	\$ —	\$ 155
2022	46	56	26	2	—	130
Capital expenditures:						
2023	\$ 264	\$ 134	\$ 161	\$ 2	\$ —	\$ 561
2022	218	103	87	1	—	409
Total assets:						
March 31, 2023	\$ 10,795	\$ 5,804	\$ 5,013	\$ 4,638	\$ (42)	\$ 26,208
December 31, 2022	10,657	5,802	4,979	4,677	(33)	26,082

(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 expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 15 — Supplemental Financial Information for additional information on total utility taxes.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 5 — Segment Information

(c) Includes intersegment revenues with ComEd, BGE, and PECO, 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.

Revenues from contracts with customers	Three Months Ended March 31, 2023						
	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Electric revenues							
Residential	\$ 836	\$ 519	\$ 434	\$ 639	\$ 283	\$ 210	\$ 146
Small commercial & industrial	361	135	92	160	39	62	59
Large commercial & industrial	84	65	149	378	282	33	63
Public authorities & electric railroads	10	8	7	17	8	4	5
Other ^(a)	217	68	96	176	56	58	63
Total electric revenues^(b)	\$ 1,508	\$ 795	\$ 778	\$ 1,370	\$ 668	\$ 367	\$ 336
Natural gas revenues							
Residential	\$ —	\$ 223	\$ 278	\$ 60	\$ —	\$ 60	\$ —
Small commercial & industrial	—	75	41	26	—	26	—
Large commercial & industrial	—	1	70	1	—	1	—
Transportation	—	8	—	4	—	4	—
Other ^(c)	—	9	19	6	—	6	—
Total natural gas revenues^(d)	\$ —	\$ 316	\$ 408	\$ 97	\$ —	\$ 97	\$ —
Total revenues from contracts with customers	\$ 1,508	\$ 1,111	\$ 1,186	\$ 1,467	\$ 668	\$ 464	\$ 336
Other revenues							
Revenues from alternative revenue programs	\$ 153	\$ (4)	\$ 65	\$ 65	\$ 39	\$ 9	\$ 17
Other electric revenues ^(e)	6	4	4	4	3	1	—
Other natural gas revenues ^(e)	—	1	2	—	—	—	—
Total other revenues	\$ 159	\$ 1	\$ 71	\$ 69	\$ 42	\$ 10	\$ 17
Total revenues for reportable segments	\$ 1,667	\$ 1,112	\$ 1,257	\$ 1,536	\$ 710	\$ 474	\$ 353

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 5 — Segment Information

Revenues from contracts with customers	Three Months Ended March 31, 2022						
	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Electric revenues							
Residential	\$ 857	\$ 487	\$ 417	\$ 652	\$ 275	\$ 207	\$ 170
Small commercial & industrial	423	111	81	141	38	56	47
Large commercial & industrial	153	64	131	323	253	26	44
Public authorities & electric railroads	14	8	7	16	8	4	4
Other ^(a)	239	62	97	193	46	56	81
Total electric revenues^(b)	\$ 1,686	\$ 732	\$ 733	\$ 1,325	\$ 620	\$ 349	\$ 346
Natural gas revenues							
Residential	\$ —	\$ 218	\$ 282	\$ 51	\$ —	\$ 51	\$ —
Small commercial & industrial	—	76	45	21	—	21	—
Large commercial & industrial	—	—	65	3	—	3	—
Transportation	—	8	—	4	—	4	—
Other ^(c)	—	3	35	4	—	4	—
Total natural gas revenues^(d)	\$ —	\$ 305	\$ 427	\$ 83	\$ —	\$ 83	\$ —
Total revenues from contracts with customers	\$ 1,686	\$ 1,037	\$ 1,160	\$ 1,408	\$ 620	\$ 432	\$ 346
Other revenues							
Revenues from alternative revenue programs	\$ 40	\$ 6	\$ (12)	\$ (5)	\$ (7)	\$ (1)	\$ 3
Other electric revenues ^(e)	8	3	4	1	1	—	—
Other natural gas revenues ^(e)	—	1	2	—	—	—	—
Total other revenues	\$ 48	\$ 10	\$ (6)	\$ (4)	\$ (6)	\$ (1)	\$ 3
Total revenues for reportable segments	\$ 1,734	\$ 1,047	\$ 1,154	\$ 1,404	\$ 614	\$ 431	\$ 349

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.

(b) Includes operating revenues from affiliates in 2023 and 2022 respectively of:

- \$3 million, \$6 million at ComEd
- \$1 million, \$1 million at PECO
- \$2 million, \$2 million at BGE
- \$3 million, \$3 million at PHI
- \$1 million, \$1 million at Pepco
- \$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 2023 and 2022 respectively of:

- \$1 million, less than a \$1 million at PECO
- \$1 million, \$6 million at BGE

(e) Includes late payment charge revenues.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 6 — Accounts Receivable

6. 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, 2023							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2022	\$ 327	\$ 59	\$ 105	\$ 54	\$ 109	\$ 47	\$ 21	\$ 41
Plus: Current period provision for expected credit losses ^(a)	108	22	39	30	17	9	7	1
Less: Write-offs, net of recoveries ^(b)	46	7	14	11	14	7	2	5
Balance as of March 31, 2023	<u>\$ 389</u>	<u>\$ 74</u>	<u>\$ 130</u>	<u>\$ 73</u>	<u>\$ 112</u>	<u>\$ 49</u>	<u>\$ 26</u>	<u>\$ 37</u>

	Three Months Ended March 31, 2022							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2021	\$ 320	\$ 73	\$ 105	\$ 38	\$ 104	\$ 37	\$ 18	\$ 49
Plus: Current period provision for expected credit losses	110	26	31	26	27	11	7	9
Less: Write-offs, net of recoveries	41	7	11	5	18	8	1	9
Balance as of March 31, 2022	<u>\$ 389</u>	<u>\$ 92</u>	<u>\$ 125</u>	<u>\$ 59</u>	<u>\$ 113</u>	<u>\$ 40</u>	<u>\$ 24</u>	<u>\$ 49</u>

(a) For PECO and BGE, the change in current period provision for expected credit losses is primarily a result of increased aging of receivables.

(b) 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, 2023							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2022	\$ 82	\$ 17	\$ 9	\$ 10	\$ 46	\$ 25	\$ 7	\$ 14
Plus: Current period provision for expected credit losses	14	2	3	4	5	3	1	1
Less: Write-offs, net of recoveries ^(a)	5	1	1	2	1	—	—	1
Balance as of March 31, 2023	<u>\$ 91</u>	<u>\$ 18</u>	<u>\$ 11</u>	<u>\$ 12</u>	<u>\$ 50</u>	<u>\$ 28</u>	<u>\$ 8</u>	<u>\$ 14</u>

	Three Months Ended March 31, 2022							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2021	\$ 72	\$ 17	\$ 7	\$ 9	\$ 39	\$ 16	\$ 8	\$ 15
Plus: Current period provision for expected credit losses	14	4	3	3	4	2	1	1
Less: Write-offs, net of recoveries	5	1	1	1	2	—	—	2
Balance as of March 31, 2022	<u>\$ 81</u>	<u>\$ 20</u>	<u>\$ 9</u>	<u>\$ 11</u>	<u>\$ 41</u>	<u>\$ 18</u>	<u>\$ 9</u>	<u>\$ 14</u>

(a) Recoveries were not material to the Registrants.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 6 — Accounts Receivable

Unbilled Customer Revenue

The following table provides additional information about unbilled customer revenues recorded in the Registrants' Consolidated Balance Sheets as of March 31, 2023 and December 31, 2022.

	Unbilled customer revenues ^(a)									
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE		
March 31, 2023	\$ 709	\$ 237	\$ 149	\$ 149	\$ 174	\$ 74	\$ 49	\$ 51		
December 31, 2022	912	223	219	247	223	103	74	46		

(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

The Utility Registrants are 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 participate in the utilities' consolidated billing. The following table presents the total receivables purchased.

	Total receivables purchased							
	Exelon ^(a)	ComEd	PECO	BGE ^(a)	PHI	Pepco	DPL	ACE
Three months ended March 31, 2023	\$ 1,108	\$ 240	\$ 309	\$ 245	\$ 314	\$ 210	\$ 56	\$ 48
Three months ended March 31, 2022	1,044	248	292	222	282	174	57	51

(a) Includes \$4 million of receivables purchased from Generation prior to the separation on February 1, 2022 for the three months ended March 31, 2022.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

7. 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, 2023 ^(a)							
	Exelon	ComEd	PECO ^(b)	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	6.0	7.9	(1.4)	6.4	6.0	5.4	6.3	6.9
Plant basis differences	(4.0)	(0.3)	(15.2)	(0.7)	(1.8)	(2.5)	(1.0)	(0.9)
Excess deferred tax amortization	(6.3)	(5.7)	(2.4)	(5.4)	(7.0)	(8.4)	(8.8)	(2.0)
Amortization of investment tax credit, including deferred taxes on basis difference	(0.1)	(0.1)	—	(0.1)	(0.1)	—	(0.1)	(0.1)
Tax credits	(0.5)	(0.3)	—	(0.5)	(0.4)	(0.4)	(0.4)	(0.3)
Other	0.6	0.3	0.4	(0.1)	0.3	0.5	(0.3)	0.4
Effective income tax rate	16.7 %	22.8 %	2.4 %	20.6 %	18.0 %	15.6 %	16.7 %	25.0 %

	Three Months Ended March 31, 2022 ^(a)							
	Exelon	ComEd	PECO ^(b)	BGE ^(c)	PHI	Pepco ^(d)	DPL	ACE ^(e)
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 ^(f)	21.1	8.0	(0.1)	2.4	3.7	(4.5)	6.2	6.8
Plant basis differences	(3.6)	(0.6)	(11.3)	(0.9)	(1.6)	(2.6)	(0.7)	(1.3)
Excess deferred tax amortization	(11.5)	(6.3)	(3.2)	(17.6)	(17.7)	(17.4)	(19.4)	(22.2)
Amortization of investment tax credit, including deferred taxes on basis difference	(0.1)	(0.1)	—	(0.1)	(0.1)	—	(0.2)	(0.2)
Tax credits ^(e)	1.7	(0.3)	—	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)
Other ^(f)	2.6	—	—	(0.1)	0.2	(0.6)	0.1	(0.1)
Effective income tax rate	31.2 %	21.7 %	6.4 %	4.3 %	5.1 %	(4.5)%	6.7 %	3.7 %

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

(b) For PECO, the lower effective tax rate is primarily related to plant basis differences attributable to tax repair deductions.

(c) For PECO, the lower effective tax rate is primarily related to plant basis differences attributable to tax repair deductions. 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. For Pepco, the income tax benefit is primarily due to the Maryland and Washington, D.C. multi-year plans which resulted in the acceleration of certain income tax benefits. For ACE, the lower effective tax rate is primarily related to the acceleration of certain income tax benefits due to distribution rate case settlements.

(d) For Exelon, the higher state income taxes, net of federal income tax benefit, is primarily due to the long-term marginal state income tax rate change of approximately \$67 million and the recognition of a valuation allowance of approximately \$40 million against the net deferred tax asset position for certain standalone state filing jurisdiction as a result of the separation.

(e) For Exelon, reflects the income tax expense related to the write-off of federal tax credits subject to recapture of approximately \$15 million as a result of the separation.

(f) For Exelon, primarily reflects the nondeductible transaction costs of approximately \$19 million arising as part of the separation.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 7 — Income Taxes

Unrecognized Tax Benefits

Exelon, PHI and ACE have the following unrecognized tax benefits as of March 31, 2023 and December 31, 2022. ComEd's, PECO's, BGE's, Pepco's, and DPL's amounts are not material.

	Exelon ^(a)	PHI	ACE
March 31, 2023	\$ 148	\$ 59	\$ 17
December 31, 2022	148	59	17

(a) As of March 31, 2023 and December 31, 2022, Exelon recorded a receivable of \$50 million in Other deferred debits and other assets in the Consolidated Balance Sheet for Constellation's share of unrecognized tax benefits for periods prior to the separation.

Reasonably possible the total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

As of March 31, 2023, ACE has \$14 million of unrecognized state 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. The unrecognized tax benefit, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

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. As of March 31, 2023, Exelon recorded a payable of \$18 million in Other current liabilities that is due to 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.

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 provides that Exelon will reimburse Constellation when those allocated tax credit carryforwards are utilized. As of March 31, 2023, Exelon recorded a payable of \$212 million and \$319 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 7 — Income Taxes

Beginning in 2023, 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. Exelon is continuing to assess the financial statement impacts of the IRA and will update estimates based on future guidance issued by the U.S. Treasury.

8. Retirement Benefits (All Registrants)

Defined Benefit Pension and OPEB

The majority of the 2023 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 5.53%. The majority of the 2023 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 5.51%.

During the first quarter of 2023, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2023. This valuation resulted in an increase to the pension obligation of \$27 million and an increase to the OPEB obligation of \$2 million. Additionally, AOCI increased by \$10 million (after-tax) and regulatory assets and liabilities increased by \$18 million and \$1 million, respectively.

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, 2023 and 2022.

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2023	2022	2023	2022
Components of net periodic benefit cost:				
Service cost	\$ 39	\$ 61	\$ 6	\$ 10
Interest cost	145	110	25	19
Expected return on assets	(189)	(209)	(21)	(25)
Amortization of:				
Prior service cost (credit)	1	1	(2)	(5)
Actuarial loss	41	76	—	4
Net periodic benefit cost	\$ 37	\$ 39	\$ 8	\$ 3

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 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 8 — Retirement Benefits

Pension and OPEB Costs (Benefit)	Three Months Ended March 31,			
	2023		2022	
Exelon	\$	45	\$	42
ComEd		6		16
PECO		(3)		(2)
BGE		14		11
PHI		24		13
Pepco		8		2
DPL		4		1
ACE		4		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, 2023 and 2022.

Savings Plan Employer Contributions	Three Months Ended March 31,			
	2023		2022	
Exelon	\$	21	\$	20
ComEd		9		8
PECO		3		3
BGE		2		2
PHI		3		3
Pepco		1		1
DPL		1		1
ACE		—		—

9. 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. At Exelon, derivative economic hedges related to interest rates are recorded at fair value and offsets are recorded to Electric operating revenues or Interest expense based on the activity the transaction is economically hedging. 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.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade. Cash collateral held by 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Commodity Price Risk

The 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 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 contracts for between 10-20% of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period.
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 2022 Form 10-K for additional information.

(b) The fair value of the DPL economic hedge is not material as of March 31, 2023 and December 31, 2022.

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 and Other 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. In addition, Exelon Corporate may also utilize interest rate swaps to manage interest rate exposure and manage potential fluctuations in Electric operating revenues at the corporate level in consolidation, which are directly correlated to yields on U.S. Treasury bonds under ComEd's distribution formula rate. These interest rate swaps are accounted for as economic hedges. A hypothetical 50

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

basis point change in the interest rates associated with Exelon's interest rate swaps as of March 31, 2023 would result in an immaterial impact to Exelon's Consolidated Net Income.

Below is a summary of the interest rate hedge balances as of March 31, 2023 and December 31, 2022.

	March 31, 2023		
	Derivatives Designated as Hedging Instruments	Economic Hedges	Total
Other deferred debits (noncurrent assets)	\$ —	\$ 3	\$ 3
Total derivative assets	—	3	3
Mark-to-market derivative liabilities (current liabilities)	—	(1)	(1)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1)	—	(1)
Total mark-to-market derivative liabilities	(1)	(1)	(2)
Total mark-to-market derivative net assets	\$ (1)	\$ 2	\$ 1

	December 31, 2022		
	Derivatives Designated as Hedging Instruments	Economic Hedges	Total
Other deferred debits (noncurrent assets)	\$ 6	\$ 5	\$ 11
Total derivative assets	6	5	11
Mark-to-market derivative liabilities (current liabilities)	—	(3)	(3)
Mark-to-market derivative liabilities (noncurrent liabilities)	(4)	—	(4)
Total mark-to-market derivative liabilities	(4)	(3)	(7)
Total mark-to-market derivative net assets	\$ 2	\$ 2	\$ 4

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. The total notional of the swaps issued as of December 31, 2022 was \$1.27 billion. In January 2023, Exelon Corporate entered into \$115 million notional of 5-year maturity floating-to-fixed swaps and \$115 million notional of 10-year maturity floating-to-fixed swaps, for a total of \$230 million designated as cash flow hedges. In February 2023, Exelon terminated the previously issued floating-to-fixed swaps with a total notional of \$1.5 billion upon issuance of \$2.5 billion of debt. See Note 10 – Debt and Credit Agreements for additional information on the debt issuance. Prior to the termination, the AOCI derivative gain was \$7 million (net of tax). The settlements resulted in a cash receipt of \$10 million, which will be amortized into Interest expense in Exelon's Consolidated Statement of Operations and Comprehensive Income over the terms of the swaps. See Note 14 – Changes in Accumulated Other Comprehensive Income (Loss) for additional information.

In March 2023, Exelon Corporate entered into \$65 million notional of 5-year maturity floating-to-fixed swaps and \$65 million 10-year maturity floating-to-fixed swaps, for a total of \$130 million designated as cash flow hedges. The related AOCI derivative gain for the three months ended as of March 31, 2023 was immaterial.

Economic Hedges (Interest Rate and Other Risk)

Exelon Corporate executes derivative instruments to mitigate exposure to fluctuations in interest rates but for which the fair value or cash flow hedge elections were not made. For derivatives intended to serve as economic hedges, fair value is recorded on the balance sheet and changes in fair value each period are recognized in earnings or as a regulatory asset or liability, if regulatory requirements are met, each period.

Exelon Corporate enters into floating-to-fixed interest rate cap swaps to manage a portion of interest rate exposure in connection with existing borrowings. In the fourth quarter of 2022, Exelon Corporate entered into \$1

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 9 — Derivative Financial Instruments

billion notional of 18-month maturity floating-to-fixed interest rate cap swaps and \$850 million notional of 6-month maturity floating-to-fixed interest rate cap swaps, for a total of \$1.85 billion notional of floating-to-fixed interest rate cap swaps as of December 31, 2022. The 6-month maturity floating-to-fixed interest rate cap swaps of \$850 million notional matured in March 2023. The total remaining notional of the swaps was \$1 billion as of March 31, 2023.

Additionally, to manage potential fluctuations in Electric operating revenues related to ComEd's distribution formula rate, Exelon Corporate enters into 30-year constant maturity treasury interest rate (Corporate 30-year treasury) swaps. In the first quarter of 2023, Exelon Corporate entered into a total of \$3.6 billion notional of calendar year 2023 Corporate 30-year treasury swaps. The total notional of the swaps issued was \$4.1 billion and \$500 million as of March 31, 2023 and December 31, 2022, respectively.

For the three months ended March 31, 2023, Exelon Corporate recognized the following net pre-tax mark-to-market gains (losses) which are also recognized in Net fair value changes related to derivatives in Exelon's Consolidated Statements of Cash Flows. Exelon had no swaps for the three months ended March 31, 2022.

Income Statement Location	Gain (Loss)	
	2023	
Electric operating revenues	\$	1
Interest expense		(1)
Total	\$	—

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 decreased as of March 31, 2023 due to decreasing energy prices. The amount of cash collateral for PECO was immaterial as of March 31, 2023 and December 31, 2022. The following table reflects the Registrants' cash collateral held with external counterparties, which is recorded in Other current liabilities on their respective Consolidated Balance Sheets, as of March 31, 2023 and December 31, 2022:

	March 31, 2023		December 31, 2022	
Exelon	\$	81	\$	297
ComEd		73		77
BGE		1		23
PHI		8		197
Pepco		1		26
DPL		1		121
ACE		6		50

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, with thresholds contingent upon PECO's, BGE's, and DPL's credit rating. As of March 31, 2023, 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, 2023, they could have been required to post collateral to their counterparties of \$39 million, \$73 million, and \$14 million, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 10 — Debt and Credit Agreements

10. 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 their 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 and bilateral credit agreements as of March 31, 2023 and December 31, 2022. As of March 31, 2023 and December 31, 2022, ACE had no commercial paper borrowings:

Commercial Paper Issuer	Outstanding Commercial Paper as of		Average Interest Rate on Commercial Paper Borrowings as of	
	March 31, 2023	December 31, 2022	March 31, 2023	December 31, 2022
Exelon ^(a)	\$ 807	\$ 1,938	5.12 %	4.77 %
ComEd	409	427	5.09 %	4.71 %
PECO	145	239	5.04 %	4.71 %
BGE	243	409	5.24 %	4.81 %
PHI ^(b)	—	414	— %	4.78 %
Pepco	—	299	— %	4.79 %
DPL	—	115	— %	4.76 %

(a) Exelon Corporate had \$10 million and \$449 million in outstanding commercial paper borrowings as of March 31, 2023 and December 31, 2022, respectively.

(b) Represents the consolidated amounts of Pepco, DPL, and ACE.

Revolving Credit Agreements

Exelon Corporate and the Utility Registrants each have a 5-year revolving credit facility. The following table reflects the credit agreements:

Borrower	Aggregate Bank Commitment	Interest Rate
Exelon Corporate	\$ 900	SOFR plus 1.275 %
ComEd	1,000	SOFR plus 1.000 %
PECO	600	SOFR plus 0.900 %
BGE	600	SOFR plus 0.900 %
Pepco	300	SOFR plus 1.075 %
DPL	300	SOFR plus 1.000 %
ACE	300	SOFR plus 1.075 %

Exelon Corporate and the Utility Registrants had no outstanding amounts on the revolving credit facilities as of March 31, 2023.

The Utility Registrants have credit facility agreements, arranged at minority and community banks, which are solely utilized to issue letters of credit. The new 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 6, 2023.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

See Note 16 — Debt and Credit Agreements of the 2022 Form 10-K for additional information on the Registrants' credit facilities.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for \$500 million. The loan agreement was renewed in the first quarter of 2023 and was bifurcated into two tranches of \$300 million on March 14, 2023 and \$200 million on March 24, 2023. The agreements will expire on March 14, 2024 and March 22, 2024, respectively. Pursuant to the loan agreements, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.90% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On October 4, 2022, ComEd entered into a 364-day term loan agreement for \$150 million with a variable rate equal to SOFR plus 0.75% and an expiration date of October 3, 2023. The proceeds from this loan were used to repay outstanding commercial paper obligations. The balance of the loan was repaid on January 13, 2023 in conjunction with the \$400 million and \$575 million First Mortgage Bond agreements that were entered into on January 3, 2023. Refer to the Issuance of Long-Term Debt table below for further information.

Long-Term Debt

Issuance of Long-Term Debt

During the three months ended March 31, 2023, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Notes	5.15%	March 15, 2028	\$1,000	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes	5.30%	March 15, 2033	850	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes	5.60%	March 15, 2053	650	Repay existing indebtedness and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 134	4.90%	February 1, 2033	400	Repay outstanding commercial paper obligations and to fund other general corporate purposes.
ComEd	First Mortgage Bonds Series 135	5.30%	February 1, 2053	575	Repay outstanding commercial paper obligations and to fund other general corporate purposes.
Pepco ^(a)	First Mortgage Bonds	5.30%	March 15, 2033	85	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	5.40%	March 15, 2038	40	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	5.57%	March 15, 2053	125	Repay existing indebtedness and for general corporate purposes.
DPL ^(b)	First Mortgage Bonds	5.30%	March 15, 2033	60	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.57%	March 15, 2053	65	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	5.57%	March 15, 2053	75	Repay existing indebtedness and for general corporate purposes.

(a) On March 15, 2023, Pepco entered into a purchase agreement of First Mortgage Bonds of \$100 million at 5.35% due on September 13, 2033. The closing date of the issuance is expected to occur in September 2023.

(b) On March 15, 2023, DPL entered into a purchase agreement of First Mortgage Bonds of \$340 million, \$75 million, and \$110 million at 5.45%, 5.55% and 5.72% due on November 8, 2033, November 8, 2038, and November 8, 2053, respectively. The closing date of the issuance is expected to occur in November 2023.

Debt Covenants

As of March 31, 2023, the Registrants are in compliance with debt covenants.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 11 — Fair Value of Financial Assets and Liabilities

11. 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.

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, 2023 and December 31, 2022. The Registrants have no financial liabilities classified as Level 1 or 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, 2023				December 31, 2022			
	Carrying Amount	Fair Value			Carrying Amount	Fair Value		
		Level 2	Level 3	Total		Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year^(a)								
Exelon	\$ 40,088	\$ 33,224	\$ 2,870	\$ 36,094	\$ 37,074	\$ 29,902	\$ 2,327	\$ 32,229
ComEd	11,480	10,236	—	10,236	10,518	9,006	—	9,006
PECO	4,613	3,946	50	3,996	4,612	3,864	50	3,914
BGE	4,208	3,685	—	3,685	4,207	3,613	—	3,613
PHI	8,553	4,632	2,820	7,452	8,120	4,507	2,277	6,784
Pepco	3,995	2,295	1,507	3,802	3,751	2,229	1,205	3,434
DPL	2,061	1,183	604	1,787	1,938	1,164	458	1,622
ACE	1,831	935	709	1,644	1,757	909	614	1,523
Long-Term Debt to Financing Trusts								
Exelon	\$ 390	\$ —	\$ 392	\$ 392	\$ 390	\$ —	\$ 384	\$ 384
ComEd	205	—	207	207	205	—	204	204
PECO	184	—	185	185	184	—	180	180

(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 2022 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 2022 Form 10-K for finance lease liabilities.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 11 — Fair Value of Financial Assets and Liabilities

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 as of March 31, 2023 and December 31, 2022. The Registrants have no financial assets or liabilities measured using the NAV practical expedient:

Exelon

	As of March 31, 2023				As of December 31, 2022			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents ^(a)	\$ 523	\$ —	\$ —	\$ 523	\$ 664	\$ —	\$ —	\$ 664
Rabbi trust investments								
Cash equivalents	65	—	—	65	62	—	—	62
Mutual funds	49	—	—	49	49	—	—	49
Fixed income	—	7	—	7	—	7	—	7
Life insurance contracts	—	56	41	97	—	58	40	98
Rabbi trust investments subtotal	114	63	41	218	111	65	40	216
Interest rate derivative assets								
Derivatives designated as hedging instruments	—	—	—	—	—	6	—	6
Economic hedges	—	3	—	3	—	5	—	5
Interest rate derivative assets subtotal	—	3	—	3	—	11	—	11
Total assets	637	66	41	744	775	76	40	891
Liabilities								
Mark-to-market derivative liabilities	—	—	(98)	(98)	—	—	(84)	(84)
Interest rate derivative liabilities								
Derivatives designated as hedging instruments	—	(1)	—	(1)	—	(4)	—	(4)
Economic hedges	—	(1)	—	(1)	—	(3)	—	(3)
Interest rate derivative liabilities subtotal	—	(2)	—	(2)	—	(7)	—	(7)
Deferred compensation obligation	—	(75)	—	(75)	—	(75)	—	(75)
Total liabilities	—	(77)	(98)	(175)	—	(82)	(84)	(166)
Total net assets (liabilities)	\$ 637	\$ (11)	\$ (57)	\$ 569	\$ 775	\$ (6)	\$ (44)	\$ 725

(a) Exelon excludes cash of \$482 million and \$345 million as of March 31, 2023 and December 31, 2022, respectively, and restricted cash of \$78 million and \$81 million as of March 31, 2023 and December 31, 2022, respectively, and includes long-term restricted cash of \$180 million and \$117 million as of March 31, 2023 and December 31, 2022, respectively, which is reported in Other deferred debits and other assets in the Consolidated Balance Sheets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 11 — Fair Value of Financial Assets and Liabilities

ComEd, PECO, and BGE

	ComEd				PECO				BGE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
As of March 31, 2023												
Assets												
Cash equivalents ^(a)	\$ 454	\$ —	\$ —	\$ 454	\$ 11	\$ —	\$ —	\$ 11	\$ 1	\$ —	\$ —	\$ 1
Rabbi trust investments												
Mutual funds	—	—	—	—	8	—	—	8	9	—	—	9
Life insurance contracts	—	—	—	—	—	15	—	15	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	8	15	—	23	9	—	—	9
Total assets	454	—	—	454	19	15	—	34	10	—	—	10
Liabilities												
Mark-to-market derivative liabilities ^(b)	—	—	(98)	(98)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(8)	—	(8)	—	(4)	—	(4)
Total liabilities	—	(8)	(98)	(106)	—	(8)	—	(8)	—	(4)	—	(4)
Total net assets (liabilities)	\$ 454	\$ (8)	\$ (98)	\$ 348	\$ 19	\$ 7	\$ —	\$ 26	\$ 10	\$ (4)	\$ —	\$ 6
As of December 31, 2022												
Assets												
Cash equivalents ^(a)	\$ 392	\$ —	\$ —	\$ 392	\$ 10	\$ —	\$ —	\$ 10	\$ 23	\$ —	\$ —	\$ 23
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	7	—	—	7
Life insurance contracts	—	—	—	—	—	15	—	15	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	7	15	—	22	7	—	—	7
Total assets	392	—	—	392	17	15	—	32	30	—	—	30
Liabilities												
Mark-to-market derivative liabilities ^(b)	—	—	(84)	(84)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(7)	—	(7)	—	(4)	—	(4)
Total liabilities	—	(8)	(84)	(92)	—	(7)	—	(7)	—	(4)	—	(4)
Total net assets (liabilities)	\$ 392	\$ (8)	\$ (84)	\$ 300	\$ 17	\$ 8	\$ —	\$ 25	\$ 30	\$ (4)	\$ —	\$ 26

- (a) ComEd excludes cash of \$51 million and \$42 million as of March 31, 2023 and December 31, 2022, respectively, and restricted cash of \$73 million and \$77 million as of March 31, 2023 and December 31, 2022, respectively, and includes long-term restricted cash of \$180 million and \$117 million as of March 31, 2023 and December 31, 2022, respectively, which is reported in Other deferred debits and other assets in the Consolidated Balance Sheets. PECO excludes cash of \$25 million and \$58 million as of March 31, 2023 and December 31, 2022, respectively. BGE excludes cash of \$19 million and \$43 million as of March 31, 2023 and December 31, 2022, respectively, and restricted cash of \$1 million and \$1 million as of March 31, 2023 and December 31, 2022, respectively.
- (b) The Level 3 balance consists of the current and noncurrent liability of \$22 million and \$76 million, respectively, as of March 31, 2023 and \$5 million and \$79 million, respectively, as of December 31, 2022 related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 11 — Fair Value of Financial Assets and Liabilities

PHI, Pepco, DPL, and ACE

PHI	As of March 31, 2023				As of December 31, 2022			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents ^(a)	\$ 35	\$ —	\$ —	\$ 35	\$ 205	\$ —	\$ —	\$ 205
Rabbi trust investments								
Cash equivalents	62	—	—	62	59	—	—	59
Mutual funds	10	—	—	10	11	—	—	11
Fixed income	—	7	—	7	—	7	—	7
Life insurance contracts	—	20	39	59	—	22	39	61
Rabbi trust investments subtotal	72	27	39	138	70	29	39	138
Total assets	107	27	39	173	275	29	39	343
Liabilities								
Deferred compensation obligation	—	(13)	—	(13)	—	(14)	—	(14)
Total liabilities	—	(13)	—	(13)	—	(14)	—	(14)
Total net assets	\$ 107	\$ 14	\$ 39	\$ 160	\$ 275	\$ 15	\$ 39	\$ 329

As of March 31, 2023	Pepco				DPL				ACE			
	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)	\$ 26	\$ —	\$ —	\$ 26	\$ 1	\$ —	\$ —	\$ 1	\$ 1	\$ —	\$ —	\$ 1
Rabbi trust investments												
Cash equivalents	61	—	—	61	—	—	—	—	—	—	—	—
Life insurance contracts	—	20	39	59	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	61	20	39	120	—	—	—	—	—	—	—	—
Total assets	87	20	39	146	1	—	—	1	1	—	—	1
Liabilities												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total liabilities	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total net assets	\$ 87	\$ 19	\$ 39	\$ 145	\$ 1	\$ —	\$ —	\$ 1	\$ 1	\$ —	\$ —	\$ 1

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 11 — Fair Value of Financial Assets and Liabilities

As of December 31, 2022	Pepco				DPL				ACE			
	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)	\$ 51	\$ —	\$ —	\$ 51	\$ 121	\$ —	\$ —	\$ 121	\$ 1	\$ —	\$ —	\$ 1
Rabbi trust investments												
Cash equivalents	59	—	—	59	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	38	60	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	59	22	38	119	—	—	—	—	—	—	—	—
Total assets	110	22	38	170	121	—	—	121	1	—	—	1
Liabilities												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total liabilities	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total net assets	\$ 110	\$ 21	\$ 38	\$ 169	\$ 121	\$ —	\$ —	\$ 121	\$ 1	\$ —	\$ —	\$ 1

(a) PHI excludes cash of \$358 million and \$165 million as of March 31, 2023 and December 31, 2022, respectively, and restricted cash of \$3 million and \$3 million as of March 31, 2023 and December 31, 2022, respectively. Pepco excludes cash of \$124 million and \$45 million as of March 31, 2023 and December 31, 2022, respectively, and restricted cash of \$3 million and \$3 million as of March 31, 2023 and December 31, 2022, respectively. DPL excludes cash of \$142 million and \$31 million as of March 31, 2023 and December 31, 2022, respectively. ACE excludes cash of \$70 million and \$71 million as of March 31, 2023 and December 31, 2022, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 11 — Fair Value of Financial Assets and Liabilities

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, 2023 and 2022:

	Exelon	ComEd	PHI and Pepco
	Total	Mark-to-Market Derivatives	Life Insurance Contracts
Three Months Ended March 31, 2023			
Balance as of December 31, 2022	\$ (44)	\$ (84)	\$ 40
Total realized / unrealized gains			
Included in net income ^(a)	1	—	1
Included in regulatory assets/liabilities	(14)	(14) ^(b)	—
Balance as of March 31, 2023	\$ (57)	\$ (98) ^(c)	\$ 41
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of March 31, 2023	\$ 1	\$ —	\$ 1
Three Months Ended March 31, 2022			
Balance as of December 31, 2021	\$ (182)	\$ (219)	\$ 35
Total realized / unrealized gains			
Included in net income ^(a)	1	—	1
Included in regulatory assets	75	75 ^(b)	—
Transfers out of Level 3	(1)	—	—
Balance as of March 31, 2022	\$ (107)	\$ (144)	\$ 36
The amount of total gains included in income attributed to the change in unrealized gain related to assets and liabilities as of March 31, 2022	\$ 1	\$ —	\$ 1

(a) Classified in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

(b) Includes \$25 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, 2023. Includes \$69 million of increases in fair value and an increase for realized losses due to settlements of \$6 million recorded in Purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2022.

(c) The balance consists of a current and noncurrent liability of \$22 million and \$76 million, respectively, as of March 31, 2023.

Valuation Techniques Used to Determine Fair Value

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 2022 Form 10-K.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 11 — Fair Value of Financial Assets and Liabilities

Mark-to-Market Derivatives (Exelon and ComEd)

The table below discloses the significant unobservable inputs to the forward curve used to value mark-to-market derivatives.

Type of trade	Fair Value as of March 31, 2023	Fair Value as of December 31, 2022	Valuation Technique	Unobservable Input	2023 Range & Arithmetic Average		2022 Range & Arithmetic Average					
Mark-to-market derivatives	\$ (98)	\$ (84)	Discounted Cash Flow	Forward power price ^(a)	\$22.49	-	\$83.26	\$47.69	\$34.78	-	\$75.71	\$48.44

(a) An increase to the forward power price would increase the fair value.

12. 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 2022 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 as of March 31, 2023:

Description	Exelon	PHI	Pepco	DPL	ACE
Total commitments	\$ 513	\$ 320	\$ 120	\$ 89	\$ 111
Remaining commitments ^(a)	48	42	37	3	2

(a) Remaining commitments extend through 2026 and include rate credits, energy efficiency programs and delivery system modernization.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 12 — Commitments and Contingencies

Commercial Commitments (All Registrants). The Registrants' commercial commitments as of March 31, 2023, representing commitments potentially triggered by future events were as follows:

	Total	Expiration within					
		2023	2024	2025	2026	2027	2028 and beyond
Exelon							
Letters of credit	\$ 19	\$ 17	\$ 2	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	205	190	15	—	—	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values ^(b)	29	—	5	6	5	4	9
Total commercial commitments	\$ 631	\$ 207	\$ 22	\$ 6	\$ 5	\$ 4	\$ 387
ComEd							
Letters of credit	\$ 12	\$ 10	\$ 2	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	47	42	5	—	—	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	\$ 259	\$ 52	\$ 7	\$ —	\$ —	\$ —	\$ 200
PECO							
Letters of credit	\$ 1	\$ 1	\$ —	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	2	1	1	—	—	—	—
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	\$ 181	\$ 2	\$ 1	\$ —	\$ —	\$ —	\$ 178
BGE							
Letters of credit	\$ 2	\$ 2	\$ —	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	3	2	1	—	—	—	—
Total commercial commitments	\$ 5	\$ 4	\$ 1	\$ —	\$ —	\$ —	\$ —
PHI							
Surety bonds ^(a)	\$ 95	\$ 90	\$ 5	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	29	—	5	6	5	4	9
Total commercial commitments	\$ 124	\$ 90	\$ 10	\$ 6	\$ 5	\$ 4	\$ 9
Pepco							
Surety bonds ^(a)	\$ 84	\$ 84	\$ —	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	10	—	2	2	2	1	3
Total commercial commitments	\$ 94	\$ 84	\$ 2	\$ 2	\$ 2	\$ 1	\$ 3
DPL							
Surety bonds ^(a)	\$ 6	\$ 2	\$ 4	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	12	—	2	2	2	2	4
Total commercial commitments	\$ 18	\$ 2	\$ 6	\$ 2	\$ 2	\$ 2	\$ 4
ACE							
Surety bonds ^(a)	\$ 5	\$ 4	\$ 1	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	7	—	1	2	1	1	2
Total commercial commitments	\$ 12	\$ 4	\$ 2	\$ 2	\$ 1	\$ 1	\$ 2

(a) Surety bonds — Guarantees issued related to contract and commercial agreements, excluding bid bonds.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Note 12 — Commitments and Contingencies

(b) Represents the maximum potential obligation in the event that 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 \$65 million guaranteed by Exelon and PHI, of which \$21 million, \$27 million, and \$17 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.

- ComEd has 20 sites that are 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 that are 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 2024.
- BGE has 4 sites that currently require some level of remediation and/or ongoing activity. BGE expects the majority of the remediation at these sites to continue through at least 2025.
- DPL has 1 site that is 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 completion of 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 12 — Commitments and Contingencies

As of March 31, 2023 and December 31, 2022, 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, 2023		December 31, 2022	
	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	\$ 421	\$ 343	\$ 409	\$ 355
ComEd	313	312	325	324
PECO	25	23	25	23
BGE	9	8	9	8
PHI	70	—	46	—
Pepco	68	—	44	—
DPL	1	—	1	—
ACE	1	—	1	—

Benning Road Site (Exelon, PHI, and Pepco). In September 2010, PHI received a letter from 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 DOEE approved on February 3, 2020. The Pepco Entities are completing a FS to evaluate possible remedial alternatives for submission to DOEE. In October 2022, 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. After completion and approval of the landside FS, now scheduled for September 2023, DOEE will prepare a Proposed Plan for public comment and then issue a Record of Decision (ROD) identifying any further response actions determined to be necessary to address any landside issues. The DOEE will issue a separate ROD for the waterside FS when that work is completed which is now anticipated to be by March 31, 2024.

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, 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 river-wide 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 DOEE's contractor.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 12 — Commitments and Contingencies

On September 30, 2020, DOEE released its Interim ROD. 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 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 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 to enter into settlement discussions. Since that time Exelon and the other PRPs at the site have exchanged letters with the D.C. OAG exploring potential settlement options. Those discussions are ongoing. Exelon, PHI, and Pepco have determined that it is probable that costs for remediation will be incurred and have accrued a liability for management’s best estimate of its share of the costs. Pepco 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 entered into negotiations with the Trustees to evaluate possible incorporation of NRD assessment and restoration as part of its remedial activities associated with the Benning site to accelerate the NRD benefits for that portion of the Anacostia River Sediment Project (ARSP) assessment. Pepco has concluded that a loss associated with the eventual NRD assessment is reasonably possible. Due to the very early stage of the assessment process, Pepco cannot reasonably estimate the final range of loss potentially resulting from this process.

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 ARSP 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. The D.C. OAG invited Pepco to resolve the threatened enforcement action through a court-approved consent decree, and Pepco is engaged in discussions with the D.C. OAG regarding a potential resolution. Exelon, PHI, and Pepco have determined that a loss associated with this matter is probable and have accrued an estimated liability. Pepco concluded that incremental exposure is reasonably possible, but the range of loss cannot be reasonably estimated beyond the amounts 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. On October 22, 2019, the SEC notified Exelon and ComEd that it had also opened an investigation into their lobbying activities. On July 17, 2020, ComEd entered into a DPA with the USAO to resolve the USAO investigation. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the former Speaker of the Illinois House of Representatives and the Speaker’s associates, with the intent to influence the Speaker’s action regarding legislation affecting ComEd’s

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 12 — Commitments and Contingencies

interests. The DPA provides that the USAO will defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period subject to certain obligations of ComEd, including payment to the U.S. Treasury of \$200 million, which was paid in November 2020. Exelon was not made a party to the DPA, and therefore the investigation by the USAO into Exelon's activities ended with no charges being brought against Exelon. The SEC's investigation remains ongoing and Exelon and ComEd have cooperated fully and intend to continue to cooperate fully with the SEC. Exelon and ComEd cannot predict the outcome of the SEC investigation. No loss contingency has been reflected in Exelon's and ComEd's consolidated financial statements with respect to the SEC investigation, as this contingency is neither probable nor reasonably estimable at this time.

Subsequent to Exelon announcing the receipt of the subpoenas, various lawsuits were filed, and various demand letters were received related to the subject of the subpoenas, the conduct described in the DPA and the SEC's investigation, including:

- Four putative class action lawsuits against ComEd and Exelon were filed in federal court on behalf of ComEd customers in the third quarter of 2020 alleging, among other things, civil violations of federal racketeering laws. In addition, the Citizens Utility Board (CUB) filed a motion to intervene in these cases on October 22, 2020 which was granted on December 23, 2020. On September 9, 2021, the federal court granted Exelon's and ComEd's motion to dismiss and dismissed the plaintiffs' and CUB's federal law claim with prejudice. The federal court also dismissed the related state law claims made by the federal plaintiffs and CUB on jurisdictional grounds. Plaintiffs appealed dismissal of the federal law claim to the Seventh Circuit Court of Appeals. Plaintiffs and CUB also refiled their state law claims in state court and moved to consolidate them with the already pending consumer state court class action, discussed below. On August 22, 2022, the Seventh Circuit affirmed the dismissal of the consolidated federal cases in their entirety. The time to further appeal has passed and the Seventh Circuit's decision is final.
- Three putative class action lawsuits against ComEd and Exelon were filed in Illinois state court in the third quarter of 2020 seeking restitution and compensatory damages on behalf of ComEd customers. The cases were consolidated into a single action in October of 2020. In November 2020, CUB filed a motion to intervene in the cases pursuant to an Illinois statute allowing CUB to intervene as a party or otherwise participate on behalf of utility consumers in any proceeding which affects the interest of utility consumers. On November 23, 2020, the court allowed CUB's intervention, but denied CUB's request to stay these cases. Plaintiffs subsequently filed a consolidated complaint, and ComEd and Exelon filed a motion to dismiss on jurisdictional and substantive grounds on January 11, 2021. Briefing on that motion was completed on March 2, 2021. The parties agreed, on March 25, 2021, along with the federal court plaintiffs discussed above, to jointly engage in mediation. The parties participated in a one-day mediation on June 7, 2021 but no settlement was reached. On December 23, 2021, the state court granted ComEd and Exelon's motion to dismiss with prejudice. On December 30, 2021, plaintiffs filed a motion to reconsider that dismissal and for permission to amend their complaint. The court denied the plaintiffs' motion on January 21, 2022. Plaintiffs have appealed the court's ruling dismissing their complaint to the First District Court of Appeals. On February 15, 2022, Exelon and ComEd moved to dismiss the federal plaintiffs' refiled state law claims, seeking dismissal on the same legal grounds asserted in their motion to dismiss the original state court plaintiffs' complaint. The court granted dismissal of the refiled state claims on February 16, 2022. The original federal plaintiffs appealed that dismissal on February 18, 2022. The two state appeals were consolidated on March 21, 2022. The appellate briefing is complete and the parties are awaiting oral argument and/or a decision.
- On November 3, 2022, a plaintiff filed a putative class action complaint in Lake County, Illinois Circuit Court against ComEd and Exelon for unjust enrichment and deceptive business practices in connection with the conduct giving rise to the DPA. Plaintiff seeks an accounting and disgorgement of any benefits ComEd allegedly obtained from said conduct. Plaintiff served initial discovery requests on ComEd in December 2022, to which ComEd has responded. ComEd and Exelon filed a motion to dismiss the Complaint on February 3, 2023. The parties fully briefed the motion, and on April 21, 2023, the court heard oral argument on the motion. The court expects to issue its ruling on the motion to dismiss on or before June 9, 2023.
- A putative class action lawsuit against Exelon and certain officers of Exelon and ComEd was filed in federal court in December 2019 alleging misrepresentations and omissions in Exelon's SEC filings

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 12 — Commitments and Contingencies

related to ComEd's lobbying activities and the related investigations. The complaint was amended on September 16, 2020, to dismiss two of the original defendants and add other defendants, including ComEd. Defendants filed a motion to dismiss in November 2020. The court denied the motion in April 2021. On May 26, 2021, defendants moved the court to certify its order denying the motion to dismiss for interlocutory appeal. Briefing on the motion was completed in June 2021. That motion was denied on January 28, 2022. In May 2021, the parties each filed respective initial discovery disclosures. On June 9, 2021, defendants filed their answer and affirmative defenses to the complaint and the parties engaged thereafter in discovery. On September 9, 2021, the U.S. government moved to intervene in the lawsuit and stay discovery until the parties entered into an amendment to their protective order that would prohibit the parties from requesting discovery into certain matters, including communications with the U.S. government. The court ordered said amendment to the protective order on November 15, 2021 and discovery resumed. The court further amended the protective order on October 17, 2022 and extended it until May 15, 2023. The next court status is set for June 27, 2023. Based on recent developments, management has determined that a probable loss exists for this matter in the amount of \$173 million. Management anticipates that such loss would be fully covered by insurance. The probable loss and the expected insurance recovery are reflected in Exelon's Consolidated Balance Sheets within Accrued expenses and Other accounts receivable, respectively.

- Several shareholders have sent letters to the Exelon Board of Directors since 2020 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. On October 12, 2021, the parties to the derivative action filed an agreed motion to stay that litigation for 120 days in order to allow the SLC to continue its investigation, which the court granted. The stay has been extended several times. On March 27, 2023, the court issued an order further extending the stay until June 9, 2023, with a status report due by May 31, 2023. The parties participated in a mediation in February 2023 and efforts to resolve the matter remain ongoing. On April 26 and May 1, 2023, two additional demand letter shareholders each filed a separate derivative lawsuit against current and former Exelon and ComEd officers and directors, and certain third parties, and against Exelon as nominal defendant, asserting claims similar to those made in their respective demand letters.
- Several shareholders have sent requests seeking review of certain Exelon books and records since August 2021. Exelon has responded to each request.

Except as noted above, no loss contingencies have been reflected in Exelon's and ComEd's consolidated financial statements with respect to these matters, as such contingencies are neither probable nor reasonably estimable at this time.

In August 2022, the ICC concluded its investigation initiated on August 12, 2021 into rate impacts of conduct admitted in the DPA, including the costs recovered from customers related to the DPA and Exelon's funding of the fine paid by ComEd. On August 17, 2022, the ICC issued its final order accepting ComEd's voluntary customer refund offer of approximately \$38 million (of which about \$31 million is ICC jurisdictional; the remaining balance is FERC jurisdictional) that resolves the question of whether customer funds were used for DPA related activities. The customer refund includes the cost of every individual or entity that was either (i) identified in the DPA or (ii) identified by ComEd as an associate of the former Speaker of the Illinois House of Representatives in the ICC proceeding. The ICC rejected an argument by the Illinois Attorney General, City of Chicago, and CUB that a costly permanent adjustment also needed to be made to ComEd's ratemaking capital structure on account of Exelon having funded ComEd's payment of the DPA fine with an equity infusion. On October 6, the ICC denied the application for rehearing filed by the Illinois Attorney General, City of Chicago, and CUB that specifically focused on their capital structure argument. The window to file an appeal on the ICC final order has expired and the ICC's DPA investigation is now closed. An accrual for the amount of the customer refund has been recorded in Regulatory liabilities and Regulatory assets in Exelon's and ComEd's Consolidated Balance Sheets as of March 31, 2023. The ICC jurisdictional refund is being made to customers during the April 2023 billing cycle, as required by the ICC. The FERC jurisdictional refund will be made as part of the next transmission formula rate

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Note 12 — Commitments and Contingencies

update proceeding in 2023. The customer refund will not be recovered in rates or charged to customers and ComEd will not seek or accept reimbursement or indemnification from any source other than Exelon.

Savings Plan Claim (Exelon). On December 6, 2021, seven current and former employees filed a putative ERISA class action suit in U.S. District Court for the Northern District of Illinois against Exelon, its Board of Directors, the former Board Investment Oversight Committee, the Corporate Investment Committee, individual defendants, and other unnamed fiduciaries of the Exelon Corporation Employee Savings Plan (Plan). The complaint alleges that the defendants violated their fiduciary duties under the Plan by including certain investment options that allegedly were more expensive than and underperformed similar passively-managed or other funds available in the marketplace and permitting a third-party administrative service provider/recordkeeper and an investment adviser to charge excessive fees for the services provided. The plaintiffs seek declaratory, equitable and monetary relief on behalf of the Plan and participants. On February 16, 2022, the court granted the parties' stipulated dismissal of the individual named defendants without prejudice. The remaining defendants filed a motion to dismiss the complaint on February 25, 2022. On March 4, 2022, the Chamber of Commerce filed a brief of amicus curiae in support of the defendants' motion to dismiss. On September 22, 2022, the court granted Exelon's motion to dismiss without prejudice. The court granted plaintiffs leave until October 31, 2022 to file an amended complaint, which was later extended to November 30, 2022. Plaintiffs filed their amended complaint on November 30, 2022. Defendants filed their motion to dismiss the amended complaint on January 20, 2023. Briefing on the motion to dismiss is now complete and the parties await a ruling. No loss contingencies have been reflected in Exelon's consolidated financial statements with respect to this matter, as such contingencies are neither probable nor reasonably estimable at this time.

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.

13. Shareholders' Equity (Exelon)

At-the-Market (ATM) 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 \$1.0 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. As of March 31, 2023, Exelon has not issued any shares of Common Stock under the ATM program and has not entered into any forward sale agreements.

14. Changes in Accumulated Other Comprehensive Income (Loss) (Exelon)

The following tables present changes in Exelon's AOCI, net of tax, by component:

Three Months Ended March 31, 2023	Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items ^(a)	Foreign Currency Items	Total
Balance as of December 31, 2022	\$ 2	\$ (640)	\$ —	\$ (638)
OCI before reclassifications	6	(10)	—	(4)
Amounts reclassified from AOCI	—	3	—	3
Net current-period OCI	6	(7)	—	(1)
Balance as of March 31, 2023	\$ 8	\$ (647)	\$ —	\$ (639)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 14 — Changes in Accumulated Other Comprehensive Income

Three Months Ended March 31, 2022	Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items ^(a)	Foreign Currency Items	Total
Balance as of December 31, 2021	\$ (6)	\$ (2,721)	\$ (23)	\$ (2,750)
Separation of Constellation	6	1,994	23	2,023
Amounts reclassified from AOCI	—	14	—	14
Net current-period OCI	—	14	—	14
Balance as of March 31, 2022	\$ —	\$ (713)	\$ —	\$ (713)

(a) This AOCI component is included in the computation of net periodic pension and OPEB cost. Additionally, as of February 1, 2022, in connection with the separation, Exelon's pension and OPEB plans were remeasured. See Note 14 — Retirement Benefits of the 2022 Form 10-K and Note 8 — Retirement Benefits 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,	
	2023	2022
Pension and non-pension postretirement benefit plans:		
Actuarial loss reclassified to periodic benefit cost	\$ (1)	\$ (5)
Pension and non-pension postretirement benefit plans valuation adjustment	3	—
Unrealized gain on cash flow hedges	(1)	—

15. 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:

Three Months Ended March 31, 2023	Taxes other than income taxes							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes ^(a)	\$ 220	\$ 74	\$ 40	\$ 29	\$ 77	\$ 68	\$ 8	\$ 1
Property	99	10	4	50	35	24	11	—
Payroll	32	7	5	5	7	2	1	1
Three Months Ended March 31, 2022								
Utility taxes ^(a)	\$ 221	\$ 78	\$ 38	\$ 27	\$ 78	\$ 70	\$ 7	\$ 1
Property	94	10	4	46	34	23	10	1
Payroll	37	7	4	4	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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 15 — Supplemental Financial Information

	Other, Net							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2023								
AFUDC — Equity	\$ 38	\$ 10	\$ 6	\$ 3	\$ 19	\$ 14	\$ 2	\$ 3
Non-service net periodic benefit cost	(1)	—	—	—	—	—	—	—
Three Months Ended March 31, 2022								
AFUDC — Equity	\$ 36	\$ 8	\$ 7	\$ 6	\$ 15	\$ 11	\$ 2	\$ 2
Non-service net periodic benefit cost	17	—	—	—	—	—	—	—

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 ^(a)	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2023								
Property, plant, and equipment ^(b)	\$ 680	\$ 267	\$ 95	\$ 124	\$ 180	\$ 76	\$ 51	\$ 47
Amortization of regulatory assets ^(b)	178	71	3	43	61	32	9	20
Amortization of intangible assets, net ^(b)	2	—	—	—	—	—	—	—
Total depreciation and amortization	\$ 860	\$ 338	\$ 98	\$ 167	\$ 241	\$ 108	\$ 60	\$ 67
Three Months Ended March 31, 2022								
Property, plant, and equipment ^(b)	\$ 726	\$ 254	\$ 88	\$ 117	\$ 164	\$ 72	\$ 45	\$ 41
Amortization of regulatory assets ^(b)	179	67	4	54	54	36	12	6
Amortization of intangible assets, net ^(b)	6	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities ^(c)	3	—	—	—	—	—	—	—
Nuclear fuel ^(d)	66	—	—	—	—	—	—	—
ARO accretion ^(e)	44	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	\$ 1,024	\$ 321	\$ 92	\$ 171	\$ 218	\$ 108	\$ 57	\$ 47

- (a) Exelon's 2022 amounts include amounts related to Generation prior to the separation. See Note 2 — Discontinued Operations for additional information.
- (b) Included in Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income.
- (c) Included in Electric operating revenues or Purchased power expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.
- (d) Included in Purchased fuel expense in Exelon's Consolidated Statement of Operations and Comprehensive Income.
- (e) Included in Operating and maintenance expense in Exelon's Consolidated Statement of Operations and Comprehensive Income.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 15 — Supplemental Financial Information

	Other non-cash operating activities							
	Exelon ^(a)	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2023								
Pension and OPEB costs (benefit)	\$ 45	\$ 6	\$ (3)	\$ 14	\$ 24	\$ 8	\$ 4	\$ 4
Allowance for credit losses	70	—	37	18	15	7	5	3
True-up adjustments to decoupling mechanisms and formula rates ^(b)	(282)	(153)	4	(65)	(68)	(39)	(11)	(18)
Long-term incentive plan	2	—	—	—	—	—	—	—
Amortization of operating ROU asset	10	1	—	1	7	1	2	1
Change in environmental liabilities	25	—	—	—	25	25	—	—
AFUDC — Equity	(38)	(10)	(6)	(3)	(19)	(14)	(2)	(3)
Three Months Ended March 31, 2022								
Pension and OPEB costs (benefit)	\$ 44	\$ 16	\$ (2)	\$ 12	\$ 13	\$ 2	\$ 1	\$ 3
Allowance for credit losses	78	17	27	18	18	9	6	3
Other decommissioning-related activity	36	—	—	—	—	—	—	—
Energy-related options	60	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates ^(b)	(29)	(40)	(6)	12	5	7	1	(3)
Long-term incentive plan	25	—	—	—	—	—	—	—
Amortization of operating ROU asset	23	1	—	7	7	2	2	1
AFUDC — Equity	(36)	(8)	(7)	(6)	(15)	(11)	(2)	(2)

(a) Exelon's 2022 amounts include amounts related to Generation prior to the separation. See Note 2 — Discontinued Operations for additional information.

(b) For ComEd, reflects the true-up adjustments in regulatory assets and liabilities associated with its 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 2022 Form 10-K for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 15 — Supplemental Financial Information

The following tables provide a reconciliation of cash, cash equivalents, and restricted cash reported within the Registrants' Consolidated Balance Sheets that sum to the total of the same amounts in their Consolidated Statements of Cash Flows.

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
March 31, 2023								
Cash and cash equivalents	\$ 522	\$ 75	\$ 27	\$ 20	\$ 367	\$ 126	\$ 142	\$ 71
Restricted cash and cash equivalents	381	323	9	1	29	27	1	—
Restricted cash included in other deferred debits and other assets	180	180	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	<u>\$ 1,083</u>	<u>\$ 578</u>	<u>\$ 36</u>	<u>\$ 21</u>	<u>\$ 396</u>	<u>\$ 153</u>	<u>\$ 143</u>	<u>\$ 71</u>
December 31, 2022								
Cash and cash equivalents	\$ 407	\$ 67	\$ 59	\$ 43	\$ 198	\$ 45	\$ 31	\$ 72
Restricted cash and cash equivalents	566	327	9	24	175	54	121	—
Restricted cash included in other deferred debits and other assets	117	117	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	<u>\$ 1,090</u>	<u>\$ 511</u>	<u>\$ 68</u>	<u>\$ 67</u>	<u>\$ 373</u>	<u>\$ 99</u>	<u>\$ 152</u>	<u>\$ 72</u>
March 31, 2022								
Cash and cash equivalents	\$ 2,476	\$ 343	\$ 26	\$ 41	\$ 796	\$ 502	\$ 120	\$ 168
Restricted cash and cash equivalents	430	246	8	34	106	34	73	—
Restricted cash included in other deferred debits and other assets	92	92	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	<u>\$ 2,998</u>	<u>\$ 681</u>	<u>\$ 34</u>	<u>\$ 75</u>	<u>\$ 902</u>	<u>\$ 536</u>	<u>\$ 193</u>	<u>\$ 168</u>
December 31, 2021								
Cash and cash equivalents	\$ 672	\$ 131	\$ 36	\$ 51	\$ 136	\$ 34	\$ 28	\$ 29
Restricted cash and cash equivalents	321	210	8	4	77	34	43	—
Restricted cash included in other deferred debits and other assets	44	43	—	—	—	—	—	—
Cash, restricted cash, and cash equivalents from discontinued operations	582	—	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	<u>\$ 1,619</u>	<u>\$ 384</u>	<u>\$ 44</u>	<u>\$ 55</u>	<u>\$ 213</u>	<u>\$ 68</u>	<u>\$ 71</u>	<u>\$ 29</u>

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the 2022 Form 10-K.

Supplemental Balance Sheet Information

The following table provides additional information about material items recorded in the Registrants' Consolidated Balance Sheets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 15 — Supplemental Financial Information

	Accrued expenses							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
March 31, 2023								
Compensation-related accruals ^(a)	\$ 359	\$ 107	\$ 43	\$ 42	\$ 59	\$ 18	\$ 11	\$ 10
Taxes accrued	214	102	3	83	94	67	14	16
Interest accrued	373	78	44	45	75	35	22	16
December 31, 2022								
Compensation-related accruals ^(a)	\$ 613	\$ 179	\$ 81	\$ 79	\$ 104	\$ 29	\$ 20	\$ 16
Taxes accrued	211	92	10	34	70	52	8	12
Interest accrued	338	124	47	42	61	32	9	14

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.

16. Related Party Transactions (All Registrants)

Utility Registrants' expense with Generation

The Utility Registrants incurred expenses from transactions with the Generation affiliate as described in the footnotes to the table below prior to separation on February 1, 2022. Such expenses were primarily recorded as Purchased power from affiliate and an immaterial amount recorded as Operating and maintenance expense from affiliates at the Utility Registrants. Effective February 1, 2022, Generation is no longer considered a related party.

	Three Months Ended March 31,	
	2022	
ComEd ^(a)	\$	59
PECO ^(b)		33
BGE ^(c)		18
PHI		51
Pepco ^(d)		39
DPL ^(e)		10
ACE ^(f)		2

- (a) ComEd had an ICC-approved RFP contract with Generation to provide a portion of ComEd's electric supply requirements. ComEd also purchased RECs and ZECs from Generation.
- (b) PECO received electric supply from Generation under contracts executed through PECO's competitive procurement process. In addition, PECO had a ten-year agreement with Generation to sell solar AECs.
- (c) BGE received a portion of its energy requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs.
- (d) Pepco received electric supply from Generation under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.
- (e) DPL received a portion of its energy requirements from Generation under its MDPSC and DEPSC approved market-based SOS commodity programs.
- (f) ACE received electric supply from Generation under contracts executed through ACE's competitive procurement process approved by the NJBPU.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 16 — Related Party Transactions

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,	
	2023	2022	2023	2022
Exelon				
BSC			\$ 175	\$ 205
PHISCO			24	19
ComEd				
BSC	\$ 83	\$ 85	81	85
PECO				
BSC	51	49	30	36
BGE				
BSC	54	51	24	38
PHI				
BSC	42	50	40	46
PHISCO	—	—	24	19
Pepco				
BSC	27	29	14	17
PHISCO	30	29	11	8
DPL				
BSC	17	18	10	14
PHISCO	24	24	7	6
ACE				
BSC	14	15	14	15
PHISCO	22	21	6	5

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Note 16 — Related Party Transactions

Current Receivables from/Payables to affiliates

The following tables present current Receivables from affiliates and current Payables to affiliates:

March 31, 2023

Payables to affiliates:	Receivables from affiliates:									
	ComEd	PECO	BGE	Pepco	DPL	ACE	BSC	PHISCO	Other	Total
ComEd	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 78	\$ —	\$ 6	\$ 84
PECO	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 1	\$ 39	\$ —	\$ 8	\$ 48
BGE	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 35	\$ —	\$ 2	\$ 37
PHI	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 7	\$ —	\$ 10	\$ 17
Pepco	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 22	\$ 15	\$ 1	\$ 38
DPL	\$ —	\$ 1	\$ —	\$ —	\$ —	\$ —	\$ 13	\$ 12	\$ —	\$ 26
ACE	\$ —	\$ 1	\$ —	\$ 1	\$ —	\$ —	\$ 13	\$ 11	\$ —	\$ 26
Other	\$ 3	\$ —	\$ —	\$ —	\$ —	\$ 1	\$ —	\$ 1	\$ —	\$ 5
Total	\$ 3	\$ 2	\$ —	\$ 1	\$ —	\$ 2	\$ 207	\$ 39	\$ 27	\$ 281

December 31, 2022

Payables to affiliates:	Receivables from affiliates:									
	ComEd	PECO	BGE	Pepco	DPL	ACE	BSC	PHISCO	Other	Total
ComEd	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 66	\$ —	\$ 8	\$ 74
PECO	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 39	\$ —	\$ 3	\$ 42
BGE	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 38	\$ —	\$ 1	\$ 39
PHI	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 4	\$ —	\$ 10	\$ 14
Pepco	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 20	\$ 13	\$ 1	\$ 34
DPL	\$ —	\$ 2	\$ —	\$ —	\$ —	\$ —	\$ 12	\$ 8	\$ —	\$ 22
ACE	\$ —	\$ 2	\$ —	\$ —	\$ —	\$ —	\$ 14	\$ 9	\$ 1	\$ 26
Other	\$ 3	\$ —	\$ —	\$ —	\$ —	\$ 1	\$ —	\$ —	\$ —	\$ 4
Total	\$ 3	\$ 4	\$ —	\$ —	\$ —	\$ 1	\$ 193	\$ 30	\$ 24	\$ 255

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, 2023			December 31, 2022		
	Exelon	ComEd	PECO	Exelon	ComEd	PECO
ComEd Financing III	\$ 206	\$ 205	\$ —	\$ 206	\$ 205	\$ —
PECO Trust III	81	—	81	81	—	81
PECO Trust IV	103	—	103	103	—	103
Total	\$ 390	\$ 205	\$ 184	\$ 390	\$ 205	\$ 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 ComEd, PECO, BGE, Pepco, DPL, and ACE.

Exelon has six reportable segments consisting of ComEd, PECO, BGE, Pepco, DPL, and ACE. See Note 1 — Significant Accounting Policies and Note 5 — 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 from continuing operations and the Utility Registrants' Net income for the three months ended March 31, 2023 compared to the same period in 2022. For additional information regarding the financial results for the three months ended March 31, 2023 and 2022 see the discussions of Results of Operations by Registrant.

	Three Months Ended March 31,				Favorable (Unfavorable) Variance
	2023	2022			
Exelon	\$	669	\$	481	\$ 188
ComEd		241		188	53
PECO		166		206	(40)
BGE		200		198	2
PHI		155		130	25
Pepco		65		46	19
DPL		60		56	4
ACE		33		26	7
Other ^(a)		(93)		(241)	148

(a) Other primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities, and other financing and investment activities.

The separation of Constellation, including Generation and its subsidiaries, meets the criteria for discontinued operations and as such, Generation's results of operations are presented as discontinued operations and have been excluded from Exelon's continuing operations for the three months ended March 31, 2022 presented in the table above. See Note 1 — Significant Accounting Policies and Note 2 — Discontinued Operations for additional information.

Accounting rules require that certain BSC costs previously allocated to Generation be presented as part of Exelon's continuing operations as these costs do not qualify as expenses of the discontinued operations. Such costs are included in Other in the table above and were \$28 million on a pre-tax basis, for the three months ended March 31, 2022.

Three Months Ended March 31, 2023 Compared to Three Months Ended March 31, 2022. Net income attributable to common shareholders from continuing operations increased by \$188 million and diluted earnings per average common share from continuing operations increased to \$0.67 in 2023 from \$0.49 in 2022 primarily due to:

- Higher electric distribution formula rate earnings from higher allowed ROE due to an increase in U.S. treasury rates and impacts of higher rate base at ComEd;
- The favorable impacts of rate increases at PECO, BGE, and PHI;
- Lower BSC costs presented in Exelon's continuing operations, which were previously allocated to Generation but did not qualify as discontinued operation expenses per the accounting rules; and
- Carrying costs related to the CMC regulatory assets at ComEd.

The increases were partially offset by:

- Unfavorable weather at PECO and PHI;
- Higher interest expense at BGE and Exelon Corporate;
- An increase in environmental liabilities at Pepco;
- Higher depreciation expense at PECO; and
- Higher credit loss expense at PECO.

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-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets, and planning and forecasting of future periods. 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 tables provide a reconciliation between Net income attributable to common shareholders from continuing operations as determined in accordance with GAAP and Adjusted (non-GAAP) operating earnings for the three months ended March 31, 2023 compared to the same period in 2022:

(In millions, except per share data)	Three Months Ended March 31,			
	2023		2022	
		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders from Continuing Operations	\$ 669	\$ 0.67	\$ 481	\$ 0.49
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of \$0)	(1)	—	—	—
Change in Environmental Liabilities (net of taxes of \$7)	18	0.02	—	—
ERP System Implementation Costs (net of taxes of \$0) ^(a)	—	—	1	—
Change in FERC Audit Liability (net of taxes of \$4)	11	0.01	—	—
Separation Costs (net of taxes of \$0 and \$7, respectively) ^(b)	(1)	—	17	0.02
Income Tax-Related Adjustments (entire amount represents tax expense) ^(c)	—	—	134	0.14
Adjusted (non-GAAP) Operating Earnings	\$ 696	\$ 0.70	\$ 634	\$ 0.64

Note:

Amounts may not sum due to rounding.

Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income 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 2023 and 2022 ranged from 24.0% to 29.0%.

- (a) Reflects costs related to a multi-year ERP system implementation, which are recorded in Operating and maintenance expense.
- (b) Represents costs related to the separation primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation, and employee-related severance costs, which are recorded in Operating and maintenance expense.
- (c) In connection with the separation, Exelon recorded an income tax expense primarily due to the long-term marginal state income tax rate change, the recognition of valuation allowances against the net deferred tax assets positions for certain standalone state filing jurisdictions, and nondeductible transaction costs.

Significant 2023 Transactions and Developments

Separation

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies ("the separation"). Exelon completed the separation on February 1, 2022. Constellation was newly formed and incorporated in Pennsylvania on June 15, 2021 for the purpose of separation and holds Generation. The separation represented a strategic shift that would have a major effect on Exelon's operations and financial results. Accordingly, the separation met the criteria for discontinued operations. See Note 2 — Discontinued Operations of the Combined Notes to Consolidated Financial Statements for additional information on the separation and discontinued operations.

In connection with the separation, Exelon incurred separation (benefit)/costs impacting continuing operations of \$(1) million and \$24 million on a pre-tax basis for the three months ended March 31, 2023 and 2022, respectively, which are recorded in Operating and maintenance expense. Total separation costs impacting continuing operations for the remainder of 2023 are not expected to be material. These costs are excluded from Adjusted (non-GAAP) Operating Earnings. The separation costs are primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation, and employee-related severance costs.

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 2023. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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	April 15, 2022	Electric	\$ 199	\$ 199	7.85 %	November 17, 2022	January 1, 2023
PECO - Pennsylvania	March 31, 2022	Natural Gas	82	55	N/A	October 27, 2022	January 1, 2023
BGE - Maryland	May 15, 2020 (amended September 11, 2020)	Electric	203	140	9.50 %	December 16, 2020	January 1, 2021
		Natural Gas	108	74	9.65 %		
Pepco - Maryland	October 26, 2020 (amended March 31, 2021)	Electric	104	52	9.55 %	June 28, 2021	June 28, 2021
DPL - Maryland	May 19, 2022	Electric	38	29	9.60 %	December 14, 2022	January 1, 2023

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois	January 17, 2023	Electric	\$ 1,472	10.50% to 10.65%	Fourth quarter of 2023
ComEd - Illinois	April 21, 2023	Electric	247	8.91 %	Fourth quarter of 2023
BGE - Maryland	February 17, 2023	Electric	313	10.40 %	Fourth quarter of 2023
		Natural Gas	289	10.40 %	
Pepco - District of Columbia	April 13, 2023	Electric	191	10.50 %	First quarter of 2024
DPL - Delaware	December 15, 2022 (amended February 28, 2023)	Electric	48	10.50 %	Second quarter of 2024
ACE - New Jersey	February 15, 2023	Electric	105	10.50 %	First quarter of 2024

Transmission Formula Rates

For 2023, the following increases/(decreases) were included in BGE's annual electric transmission formula rate updates. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Registrant	Initial Revenue Requirement Increase	Annual Reconciliation Decrease	Total Revenue Requirement Increase	Allowed Return on Rate Base	Allowed ROE
BGE	\$ 19	\$ (12)	\$ 4	7.34 %	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 May 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 covered the period from January 1, 2017 through August 31, 2022. On January 17 and February 21, 2023, ComEd was provided with information on a series of potential findings, including concerning ComEd's methodology regarding the allocation of certain overhead costs to capital under FERC regulations. As of March 31, 2023, ComEd has continued discussions with FERC staff and determined that a loss is probable and has recorded a liability that reflects management's best estimate. The final outcome and resolution of the findings or of the audit itself cannot be predicted and the results, while not reasonably estimable at this time, could be material to the Exelon and ComEd financial statements. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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 2022 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 2022 Form 10-K, and Note 12 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in this report for additional information on various environmental matters.

Legislative and Regulatory Developments

City of Chicago Franchise Agreement

The current ComEd Franchise Agreement with the City of Chicago (the City) has been in force since 1992. The Franchise Agreement grants rights to use the public right of way to install, maintain, and operate the wires, poles, and other infrastructure required to deliver electricity to residents and businesses across the City. The Franchise Agreement became terminable on one year notice as of December 31, 2020. It now continues in effect indefinitely unless and until either party issues a notice of termination, effective one year later, or it is replaced by mutual agreement with a new franchise agreement between ComEd and the City. If either party terminates and no new agreement is reached between the parties, the parties could continue with ComEd providing electric services within the City with no franchise agreement in place. The City also has an option to terminate and purchase the ComEd system ("municipalize"), which also requires one year notice. Neither party has issued a notice of termination at this time, the City has not exercised its municipalization option, and no new agreement has become effective. Accordingly, the 1992 Franchise Agreement remains in effect at this time. In April 2021, the City invited interested parties to respond to a Request for Information (RFI) regarding the franchise for electricity delivery. Final responses to the RFI were due on July 30, 2021, however, on July 29, 2021, the City chose to extend the final submission deadline to September 30, 2021. ComEd submitted its response to the RFI by the due date. However, the City did not proceed to issue an RFP. Since that time, ComEd and the City continued to negotiate and have arrived at a proposed Chicago Franchise Agreement (CFA) and an Energy and Equity Agreement (EEA). These agreements together are intended to grant ComEd the right to continue providing electric utility services using public ways within the City of Chicago, and to create a new non-profit entity to advance energy and energy-related equity projects. On February 1, 2023, the proposed CFA and EEA were introduced to the City Council. The proposed CFA and EEA remain subject to approval by the City Council and the Exelon Board.

While Exelon and ComEd cannot predict the ultimate outcome of these processes, fundamental changes in the agreements or other adverse actions affecting ComEd's business in the City would require changes in their business planning models and operations and could have a material adverse impact on Exelon's and ComEd's consolidated financial statements. If the City were to disconnect from the ComEd system, ComEd would seek full compensation for the business and its associated property taken by the City, as well as for all damages resulting to ComEd and its system. ComEd would also seek appropriate compensation for stranded costs with FERC.

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. Federal agencies are developing guidelines to implement spending programs under IIJA. The time needed to develop these guidelines will vary with some limited program applications opened as early as the first quarter of 2022. The Registrants are continuing to analyze the legislation and considering 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.

In September 2022, ComEd and BGE applied for the MMG, which establishes and funds construction, improvement, or acquisition of middle mile broadband infrastructure which creates high-speed internet services. The MMG addresses inequitable broadband access by expansion and extension of the middle mile infrastructure in underserved communities. The grant process is expected to be highly competitive, and therefore, ComEd and

BGE cannot predict how many of their total applications will be approved as filed or the precise timing of receiving any funds if they are awarded a grant.

In March 2023, Exelon, ComEd and PHI submitted three applications related to the Smart Grid Grants program under section 40107 of IJJA. These applications are focused on replacing existing Advanced Distribution Management Systems (ADMS) in support of distributed energy resources (DERs) and grid-edged technologies, strengthening interoperability and data architecture of systems in support of two-way power flows and accelerating advanced metering deployment in disadvantaged communities. In April 2023, ComEd, PECO BGE and PHI submitted seven applications related to the Grid Resilience Grants program under section 40101(c) of IJJA. These applications are broadly focused on improving grid resilience with an emphasis on disadvantaged communities, relief of capacity constraints and modernizing infrastructure, deployment of DER and microgrid technologies and providing improved resilience through storm hardening projects. Through its applications under section 40107 and 40101(c) of IJJA, the Registrants are requesting nearly \$700 million in proposed federal funding. The grant process is expected to be highly competitive, and therefore, the Registrants cannot predict how many of their total applications will be approved as filed, or the precise timing of receiving any funds if they are awarded a grant.

The Registrants are supporting three different Regional Clean Hydrogen Hub opportunities, covering all five states that Exelon operates in plus Washington D.C. under a program that will create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of hydrogen as a clean energy carrier that can deliver or store energy. Applications for the three opportunities under this program were submitted in April 2023. The selection process is expected to be highly competitive, and therefore, the Registrants cannot predict how many of their total applications will be approved as filed or the precise timing of receiving any funds if they are awarded a grant.

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, 2023, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2022. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in the 2022 Form 10-K for further information.

Results of Operations by Registrant

Results of Operations — ComEd

	Three Months Ended March 31,		(Unfavorable) Favorable Variance
	2023	2022	
Operating revenues	\$ 1,667	\$ 1,734	\$ (67)
Operating expenses			
Purchased power	488	638	150
Operating and maintenance	337	351	14
Depreciation and amortization	338	321	(17)
Taxes other than income taxes	93	96	3
Total operating expenses	1,256	1,406	150
Operating income	411	328	83
Other income and (deductions)			
Interest expense, net	(117)	(100)	(17)
Other, net	18	12	6
Total other income and (deductions)	(99)	(88)	(11)
Income before income taxes	312	240	72
Income taxes	71	52	(19)
Net income	\$ 241	\$ 188	\$ 53

Three Months Ended March 31, 2023 Compared to Three Months Ended March 31, 2022. Net income increased by \$53 million as compared to the same period in 2022, primarily due to increases in electric distribution formula rate earnings (reflecting higher allowed ROE due to an increase in U.S. Treasury rates and the impacts of higher rate base) and carrying costs related to the CMC regulatory assets.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2023 Increase (Decrease)
Distribution	\$ 111
Transmission	(12)
Energy efficiency	14
Other	2
	115
Regulatory required programs	(182)
Total decrease	\$ (67)

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 implemented pursuant to FEJA.

Distribution Revenue. EIMA and FEJA provide for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. 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 revenue increased for the three months ended March 31, 2023 as compared to the same period in 2022, due to higher allowed ROE due to an increase in U.S. Treasury rates, the impact of a higher rate base, and higher fully recoverable costs.

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. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue.

Energy Efficiency Revenue. FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under FEJA, energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. Energy efficiency revenue increased for the three months ended March 31, 2023 as compared to the same period in 2022, 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 revenue increased for the three months ended March 31, 2023 as compared to the same period in 2022, which primarily reflects 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. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding CMCs. ETAC is a retail customer surcharge collected by electric utilities operating in Illinois established by CEJA 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. 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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The decrease of \$150 million for the three months ended March 31, 2023 compared to the same period in 2022, in **Purchased power expense** is primarily due to the CMCs from the participating nuclear-powered generating facilities including the deferral of any associated carrying costs. This favorability is offset by a decrease in Operating revenues as part of regulatory required programs. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding CMCs.

The changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended March 31, 2023	
	Increase (Decrease)	
Labor, other benefits, contracting and materials	\$	17
Storm-related costs		1
Pension and non-pension postretirement benefits expense		(4)
BSC costs		(2)
Other ^(a)		(6)
		4
Regulatory required programs ^(b)		(18)
Total decrease	\$	(14)

(a) For the three months ended March 31, 2023, the decrease is primarily due to the voluntary customer refund made in 2022 related to the ICC investigation of matters identified in the Deferred Prosecution Agreement. See Note 12 —

Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information related to the Deferred Prosecution Agreement.

(b) ComEd is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through a rider mechanism.

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2023	
	Increase	
Depreciation and amortization ^(a)	\$	13
Regulatory asset amortization ^(b)		4
Total increase	\$	17

(a) Reflects ongoing capital expenditures and higher depreciation rates effective January 2023.

(b) Includes amortization of ComEd's energy efficiency formula rate regulatory asset.

Interest expense, net increased by \$17 million for the three months ended March 31, 2023, compared to the same period in 2022, primarily due to an increase in interest rates and the issuance of debt during the year.

Effective income tax rates were 22.8% and 21.7% for the three months ended March 31, 2023 and 2022, respectively. See Note 7 — 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
	2023	2022	
Operating revenues	\$ 1,112	\$ 1,047	\$ 65
Operating expenses			
Purchased power and fuel	484	407	(77)
Operating and maintenance	270	247	(23)
Depreciation and amortization	98	92	(6)
Taxes other than income taxes	50	47	(3)
Total operating expenses	902	793	(109)
Operating income	210	254	(44)
Other income and (deductions)			
Interest expense, net	(48)	(41)	(7)
Other, net	8	7	1
Total other income and (deductions)	(40)	(34)	(6)
Income before income taxes	170	220	(50)
Income taxes	4	14	10
Net income	\$ 166	\$ 206	\$ (40)

Three Months Ended March 31, 2023 Compared to Three Months Ended March 31, 2022. Net income decreased by \$40 million, primarily due to unfavorable weather and credit loss expense, partially offset by an increase in gas distribution rates.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2023		
	(Decrease) Increase		
	Electric	Gas	Total
Weather	\$ (25)	\$ (25)	\$ (50)
Volume	(7)	2	(5)
Pricing	11	23	34
Transmission	(2)	—	(2)
Other	(1)	6	5
Regulatory required programs	78	5	83
Total increase	\$ 54	\$ 11	\$ 65

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, 2023 compared to the same period in 2022, Operating revenues related to weather decreased by the impact of 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, 2023 compared to the same period in 2022 and normal weather consisted of the following:

PECO Service Territory	Three Months Ended March 31,		Normal	% Change	
	2023	2022		2023 vs. 2022	2023 vs. Normal
Heating Degree-Days	1,888	2,228	2,418	(15.3)%	(21.9)%
Cooling Degree-Days	—	1	1	(100.0)%	(100.0)%

Volume. Electric volume, exclusive of the effects of weather, for the three months ended March 31, 2023, compared to the same period in 2022, remained relatively consistent. Natural gas volume for the three months ended March 31, 2023 compared to the same period in 2022, remained relatively consistent.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,		% Change	Weather - Normal % Change ^(b)
	2023	2022		
Residential	3,358	3,758	(10.6)%	(0.1)%
Small commercial & industrial	1,843	1,937	(4.9)%	0.4 %
Large commercial & industrial	3,237	3,332	(2.9)%	(1.2)%
Public authorities & electric railroads	168	182	(7.7)%	9.3 %
Total electric retail deliveries ^(a)	8,606	9,209	(6.5)%	(0.2)%

Number of Electric Customers	As of March 31,	
	2023	2022
Residential	1,529,779	1,521,255
Small commercial & industrial	155,846	155,485
Large commercial & industrial	3,118	3,102
Public authorities & electric railroads	10,401	10,342
Total	1,699,144	1,690,184

- (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,		% Change	Weather - Normal % Change ^(b)
	2023	2022		
Residential	17,190	20,837	(17.5)%	(2.4)%
Small commercial & industrial	8,699	10,546	(17.5)%	(3.4)%
Large commercial & industrial	29	10	190.0 %	21.7 %
Transportation	7,014	7,639	(8.2)%	(5.4)%
Total natural gas retail deliveries ^(a)	32,932	39,032	(15.6)%	(3.2)%

Number of Natural Gas Customers	As of March 31,	
	2023	2022
Residential	504,181	499,188
Small commercial & industrial	45,003	44,959
Large commercial & industrial	9	5
Transportation	650	664
Total	549,843	544,816

- (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, 2023 compared to the same period in 2022 increased primarily due to an increase in 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.

Other revenue primarily includes revenue related to late payment charges. Other revenue for the three months ended March 31, 2023 compared to the same period in 2022 remained relatively consistent.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency, PGC, and the GSA. The riders are designed to provide full and current cost recovery as well as 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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The increase of \$77 million for the three months ended March 31, 2023 compared to the same period in 2022, 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, 2023	
	Increase (Decrease)	
Labor, other benefits, contracting and materials	\$	14
Credit loss expense		10
BSC costs		2
Pension and non-pension postretirement benefit expense		(2)
Storm-related costs		(4)
Other		(3)
		17
Regulatory required programs		6
Total increase	\$	23

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2023	
	Increase (Decrease)	
Depreciation and amortization ^(a)	\$	7
Regulatory asset amortization		(1)
Total increase	\$	6

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Interest expense, net increased \$7 million for the three months ended March 31, 2023, compared to the same period in 2022, primarily due to the issuance of debt in 2022 and increases in interest rates.

Effective income tax rates were 2.4% and 6.4% for the three months ended March 31, 2023 and 2022, respectively. See Note 7 — 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,		Favorable (Unfavorable) Variance
	2023	2022	
Operating revenues	\$ 1,257	\$ 1,154	\$ 103
Operating expenses			
Purchased power and fuel	492	454	(38)
Operating and maintenance	222	218	(4)
Depreciation and amortization	167	171	4
Taxes other than income taxes	83	76	(7)
Total operating expenses	964	919	(45)
Operating income	293	235	58
Other income and (deductions)			
Interest expense, net	(44)	(35)	(9)
Other, net	3	7	(4)
Total other income and (deductions)	(41)	(28)	(13)
Income before income taxes	252	207	45
Income taxes	52	9	(43)
Net income	\$ 200	\$ 198	\$ 2

Three Months Ended March 31, 2023 Compared to Three Months Ended March 31, 2022. Net income increased \$2 million primarily due to a favorable impacts of the multi-year plans, partially offset by an increase in interest expense. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the three-year electric and natural gas distribution multi-year plans.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2023		
	Increase		
	Electric	Gas	Total
Distribution	\$ 26	\$ 23	\$ 49
Transmission	18	—	18
Other	—	1	1
Regulatory required programs	44	24	68
Total increase	\$ 78	\$ 25	\$ 103

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.

Number of Electric Customers	As of March 31,	
	2023	2022
Residential	1,207,486	1,199,272
Small commercial & industrial	115,658	115,363
Large commercial & industrial	12,911	12,674
Public authorities & electric railroads	266	268
Total	1,336,321	1,327,577

<u>Number of Natural Gas Customers</u>	As of March 31,	
	2023	2022
Residential	656,583	653,397
Small commercial & industrial	38,260	38,356
Large commercial & industrial	6,261	6,193
Total	701,104	697,946

Distribution Revenue increased for the three months ended March 31, 2023, compared to the same period in 2022, 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, 2023, compared to the same period in 2022, 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.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as conservation, demand response, STRIDE, 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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

The increase of \$38 million for the three months ended March 31, 2023 compared to the same period in 2022, 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, 2023	
	Increase (Decrease)	
Labor, other benefits, contracting, and materials	\$	8
Storm-related costs		(5)
Pension and non-pension postretirement benefits expense		1
BSC costs		3
Other		(3)
		4
Regulatory required programs		—
Total increase	\$	4

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2023	
	Increase (Decrease)	
Depreciation and amortization ^(a)	\$	7
Regulatory required programs		(9)
Regulatory asset amortization		(2)
Total decrease	\$	(4)

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Interest expense, net increased by \$9 million for the three months ended March 31, 2023, compared to the same period in 2022, primarily due to an increase in interest rates and the issuance of debt in Q2 2022.

Effective income tax rates were 20.6% and 4.3% for the three months ended March 31, 2023 and 2022, respectively. The change is primarily due to a decrease in the multi-year plans' accelerated income tax benefits in 2023 as compared to 2022. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the three-year electric and natural gas distribution multi-year plans and Note 7 — 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, 2023 compared to the same period in 2022. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2023	2022	
PHI	\$ 155	\$ 130	\$ 25
Pepco	65	46	19
DPL	60	56	4
ACE	33	26	7
Other ^(a)	(3)	2	(5)

(a) Primarily includes eliminating and consolidating adjustments, PHI's corporate operations, shared service entities, and other financing and investment activities.

Three Months Ended March 31, 2023 Compared to Three Months Ended March 31, 2022. Net Income increased by \$25 million primarily due to favorable impacts as a result of Pepco Maryland and DPL Maryland multi-year plans, timing of decoupling revenues in the District of Columbia, higher distribution rates at DPL Delaware, and higher transmission rates at Pepco and ACE, partially offset by an increase in environmental liabilities at Pepco, and unfavorable weather conditions at DPL Delaware electric and natural gas service territories.

Results of Operations — Pepco

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2023	2022	
Operating revenues	\$ 710	\$ 614	\$ 96
Operating expenses			
Purchased power	258	213	(45)
Operating and maintenance	150	131	(19)
Depreciation and amortization	108	108	—
Taxes other than income taxes	94	95	1
Total operating expenses	610	547	(63)
Operating income	100	67	33
Other income and (deductions)			
Interest expense, net	(39)	(36)	(3)
Other, net	16	13	3
Total other income and (deductions)	(23)	(23)	—
Income before income taxes	77	44	33
Income taxes	12	(2)	(14)
Net income	\$ 65	\$ 46	\$ 19

Three Months Ended March 31, 2023 Compared to Three Months Ended March 31, 2022. Net income increased by \$19 million primarily due to favorable impacts of the Maryland multi-year plan, timing of decoupling revenues in the District of Columbia, and higher transmission rates, partially offset by an increase in environmental liabilities.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2023 Increase
Distribution	\$ 40
Transmission	18
Regulatory required programs	38
Total increase	\$ 96

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 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 are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

Number of Electric Customers	As of March 31,	
	2023	2022
Residential	859,207	846,258
Small commercial & industrial	54,089	54,509
Large commercial & industrial	22,858	22,620
Public authorities & electric railroads	201	184
Total	936,355	923,571

Distribution Revenue increased for the three months ended March 31, 2023 compared to the same period in 2022 primarily due to favorable impacts of the Maryland multi-year plan and higher rates due to the expiration of customer offsets and timing of decoupling revenues in the District of Columbia.

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, 2023, compared to the same period in 2022, primarily due to increases in capital investment and underlying costs.

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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

The increase of \$45 million for the three months ended March 31, 2023 compared to the same period in 2022, 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, 2023	
	Increase (Decrease)	
Labor, other benefits, contracting and materials ^(a)	\$	24
Pension and non-pension postretirement benefits expense		3
Storm-related costs		(5)
Credit loss expense		(4)
BSC and PHISCO Costs		(1)
Other		(3)
		14
Regulatory required programs		5
Total increase	\$	19

(a) Primarily reflects an increase in environmental liabilities.

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2023	
	Increase (Decrease)	
Depreciation and amortization ^(a)	\$	3
Regulatory asset amortization		4
Regulatory required programs		(7)
Total increase	\$	—

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Effective income tax rates were 15.6% and (4.5)% for three months ended March 31, 2023 and 2022, respectively. See Note 7 — 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 — DPL

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2023	2022	
Operating revenues	\$ 474	\$ 431	\$ 43
Operating expenses			
Purchased power and fuel	221	189	(32)
Operating and maintenance	87	93	6
Depreciation and amortization	60	57	(3)
Taxes other than income taxes	20	18	(2)
Total operating expenses	388	357	(31)
Operating income	86	74	12
Other income and (deductions)			
Interest expense, net	(17)	(16)	(1)
Other, net	3	2	1
Total other income and (deductions)	(14)	(14)	—
Income before income taxes	72	60	12
Income taxes	12	4	(8)
Net income	\$ 60	\$ 56	\$ 4

Three Months Ended March 31, 2023 Compared to Three Months Ended March 31, 2022. Net income increased \$4 million primarily due to favorable impacts of the Maryland multi-year plan, higher Delaware electric and natural gas distribution rates, partially offset by unfavorable weather conditions at Delaware electric and natural gas service territories.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2023		
	Electric	Gas	Total
	(Decrease) Increase		
Weather	\$ (5)	\$ (4)	\$ (9)
Volume	(2)	(2)	(4)
Distribution	11	5	16
Transmission	7	—	7
	11	(1)	10
Regulatory required programs	18	15	33
Total increase	\$ 29	\$ 14	\$ 43

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 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, 2023 compared to the same period in 2022, Operating revenues related to weather decreased due to unfavorable weather conditions in Delaware electric and natural gas service territories.

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 the Delaware electric service territory and a 30-year period in the Delaware natural gas service territory. The changes in heating and cooling degree days in the Delaware service territory for the three months ended March 31, 2023 compared to same period in 2022 and normal weather consisted of the following:

Delaware Electric Service Territory	Three Months Ended March 31,			Normal	% Change	
	2023	2022			2023 vs. 2022	2023 vs. Normal
Heating Degree-Days	1,952	2,355		2,489	(17.1)%	(21.6)%
Cooling Degree-Days	—	3		1	(100.0)%	(100.0)%

Delaware Natural Gas Service Territory	Three Months Ended March 31,			Normal	% Change	
	2023	2022			2023 vs. 2022	2023 vs. Normal
Heating Degree-Days	1,952	2,355		2,497	(17.1)%	(21.8)%

Volume, exclusive of the effects of weather, decreased for the three months ended March 31, 2023 compared to the same period in 2022 primarily due to customer usage, partially offset by customer growth.

Electric Retail Deliveries to Delaware Customers (in GWhs)	Three Months Ended March 31,		Normal	% Change	Weather - Normal % Change ^(b)
	2023	2022			
Residential	797	895		(10.9)%	(1.2)%
Small commercial & industrial	327	370		(11.6)%	(7.2)%
Large commercial & industrial	719	765		(6.0)%	(4.7)%
Public authorities & electric railroads	9	9		—%	(6.3)%
Total electric retail deliveries ^(a)	1,852	2,039		(9.2)%	(3.6)%

Number of Total Electric Customers (Maryland and Delaware)	As of March 31,	
	2023	2022
Residential	482,979	478,009
Small commercial & industrial	63,794	63,296
Large commercial & industrial	1,236	1,221
Public authorities & electric railroads	595	603
Total	548,604	543,129

(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,		Normal	% Change	Weather - Normal % Change ^(b)
	2023	2022			
Residential	3,581	4,453		(19.6)%	(6.6)%
Small commercial & industrial	1,652	1,983		(16.7)%	(1.8)%
Large commercial & industrial	414	457		(9.4)%	(9.5)%
Transportation	1,900	2,207		(13.9)%	(6.9)%
Total natural gas deliveries ^(a)	7,547	9,100		(17.1)%	(5.8)%

Number of Delaware Natural Gas Customers	As of March 31,	
	2023	2022
Residential	129,791	128,695
Small commercial & industrial	10,158	10,097
Large commercial & industrial	16	17
Transportation	158	159
Total	140,123	138,968

- (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, 2023 compared to the same period in 2022 primarily due to favorable impacts of the Maryland multi-year plan that became effective in January 2023, higher natural gas distribution rates effective in August 2022, and higher DSIC rates in Delaware that became effective in January 2023.

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, 2023 compared to the same period in 2022, transmission revenue increased, primarily due to increases underlying costs.

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 5 — 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, 2023, compared to the same period in 2022, 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, 2023	
	(Decrease) Increase	
Labor, other benefits, contracting and materials	\$	(3)
Storm-related costs		(3)
BSC and PHISCO costs		(1)
Credit loss expense		(1)
Pension and non-pension postretirement benefits expense		1
		(7)
Regulatory required programs		1
Total decrease	\$	(6)

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2023	
	Increase (Decrease)	
Depreciation and amortization ^(a)	\$	7
Regulatory asset amortization		(1)
Regulatory required programs		(3)
Total increase	\$	3

(a) Reflects ongoing capital expenditures, higher distribution depreciation rates in Maryland effective March 2022 and higher transmission depreciation rates effective September 2022.

Effective income tax rates were 16.7% and 6.7% for the three months ended March 31, 2023 and 2022, respectively. See Note 7 — 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,		Favorable (Unfavorable) Variance
	2023	2022	
Operating revenues	\$ 353	\$ 349	\$ 4
Operating expenses			
Purchased power	148	178	30
Operating and maintenance	81	84	3
Depreciation and amortization	67	47	(20)
Taxes other than income taxes	2	2	—
Total operating expenses	298	311	13
Operating income	55	38	17
Other income and (deductions)			
Interest expense, net	(16)	(14)	(2)
Other, net	5	3	2
Total other income and (deductions)	(11)	(11)	—
Income before income taxes	44	27	17
Income taxes	11	1	(10)
Net income	\$ 33	\$ 26	\$ 7

Three Months Ended March 31, 2023 Compared to Three Months Ended March 31, 2022. Net income increased by \$7 million primarily due to higher transmission rates and decreases in various operating expenses.

The changes in **Operating revenues** consisted of the following:

	Three Months Ended March 31, 2023
	Increase (Decrease)
Distribution	\$ 8
Transmission	12
	20
Regulatory required programs	(16)
Total increase	\$ 4

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in New Jersey are not 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.

<u>Number of Electric Customers</u>	As of March 31,	
	2023	2022
Residential	503,260	500,511
Small commercial & industrial	62,230	62,124
Large commercial & industrial	3,030	3,124
Public authorities & electric railroads	726	724
Total	569,246	566,483

Distribution Revenue increased for the three months ended March 31, 2023 compared to the same period in 2022 due to higher distribution rates primarily due to the expiration of customer credits related to the TCJA tax benefits.

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 increased for the three months ended March 31, 2023 compared to the same period in 2022, primarily due to increases in capital investment and underlying costs.

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 Bond Charge, 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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

The decrease of \$30 million for the three months ended March 31, 2023 compared to the same period in 2022, 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, 2023	
	(Decrease) Increase	
Labor, other benefits, contracting and materials	\$	(2)
Storm-related costs		(2)
Other		2
Regulatory required programs ^(a)		(2)
Total decrease	\$	(3)

(a) ACE is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through the Societal Benefits Charge.

The changes in **Depreciation and amortization expense** consisted of the following:

	Three Months Ended March 31, 2023	
	Increase	
Depreciation and amortization ^(a)	\$	7
Regulatory asset amortization		—
Regulatory required programs ^(b)		13
Total increase	\$	20

(a) Reflects ongoing capital expenditures and higher transmission depreciation rates effective September 2022.

(b) Regulatory required programs increased primarily due to the regulatory asset amortization of the PPA termination obligation which is fully offset in Operating revenues.

Effective income tax rates were 25.0% and 3.7% for the three months ended March 31, 2023 and 2022, respectively. See Note 7 — 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 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt and credit agreements.

Cash flows related to Generation have not been presented as discontinued operations and are included in the Consolidated Statements of Cash Flows for only 2022. The Exelon Consolidated Statement of Cash Flows for the three months ended March 31, 2022 includes one month of cash flows from Generation.

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 2022 Form 10-K and Notes 3 — Regulatory Matters and 12 — 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, 2023 and 2022 by Registrant:

Increase (decrease) in cash flows from operating activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income (loss)	\$ 71	\$ 53	\$ (40)	\$ 2	\$ 25	\$ 19	\$ 4	\$ 7
Adjustments to reconcile net income to cash:								
Non-cash operating activities	(683)	(126)	(7)	(61)	(8)	(17)	(9)	14
Option premiums (paid), net	39	—	—	—	—	—	—	—
Collateral (paid) received, net	(1,356)	(47)	—	(52)	(226)	(26)	(150)	(41)
Income taxes	(54)	17	20	25	15	7	10	5
Pension and non-pension postretirement benefit contributions	530	153	12	48	60	1	1	6
Regulatory assets and liabilities, net	(293)	(330)	19	(23)	45	4	27	6
Changes in working capital and other assets and liabilities	448	24	23	93	113	70	30	3
(Decrease) increase in cash flows from operating activities	\$ (1,298)	\$ (256)	\$ 27	\$ 32	\$ 24	\$ 58	\$ (87)	\$ —

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. See above for additional information related to cash flows from Generation. Significant operating cash flow impacts for the Registrants and Generation for the three months ended March 31, 2023 and 2022 were as follows:

- See Note 15 — 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 Generation 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 decreased due to decreasing energy prices. See Note 9 — Derivative Financial Instruments for additional information.
- See Note 7 — 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 receiving an updated valuation of its pension and OPEB to reflect census data as of January 1, 2023. See Note 8 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements 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 differs from the recovery period of those costs. Included within the changes is energy efficiency spend for ComEd of \$72 million and \$50 million for the three months ended March 31, 2023 and 2022, respectively. Also included within the changes is energy efficiency and demand response programs spend for BGE, Pepco, DPL and ACE of \$33 million, \$14 million, \$5 million, and \$4 million for the three months ended March 31, 2023 and \$26 million, \$13 million, \$6 million, and \$2 million for the three months ended March 31, 2022, respectively. PECO had no energy efficiency and demand response programs spend recorded to the regulatory asset for the three months ended March 31,

2023 and 2022. See Note 3 — 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 \$125 million and for Generation total \$323 million. The change for Generation primarily relates to the revolving accounts receivable financing arrangement which was entered into in April 2020. 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, 2023, the established pricing resulted in a ComEd owing payments to nuclear-powered generating facilities, which is reported within the cash flows from operations as a change in accounts payable and accrued expense.

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, 2023 and 2022 by Registrant:

Increase (decrease) in cash flows from investing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	\$ 41	\$ —	\$ 9	\$ (47)	\$ (152)	\$ (46)	\$ (31)	\$ (74)
Investment in NDT fund sales, net	28	—	—	—	—	—	—	—
Collection of DPP	(169)	—	—	—	—	—	—	—
Proceeds from sales of assets and businesses	(16)	—	—	—	—	—	—	—
Other investing activities	64	(6)	(2)	—	6	7	(1)	—
(Decrease) increase in cash flows from investing activities	<u>\$ (52)</u>	<u>\$ (6)</u>	<u>\$ 7</u>	<u>\$ (47)</u>	<u>\$ (146)</u>	<u>\$ (39)</u>	<u>\$ (32)</u>	<u>\$ (74)</u>

Significant investing cash flow impacts for the Registrants for three months ended March 31, 2023 and 2022 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. See Note 2 — Discontinued Operations of the Combined Notes to Consolidated Financial Statements for capital expenditures related to Generation prior to the separation.
- **Collection of DPP** relates to Generation's revolving accounts receivable financing agreement which Generation entered into in April 2020.

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, 2023 and 2022 by Registrant:

(Decrease) increase in cash flows from financing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	\$ (1,380)	\$ (168)	\$ (94)	\$ (285)	\$ 54	\$ (124)	\$ 34	\$ 144
Long-term debt, net	(1,227)	225	—	—	(250)	(150)	—	(100)
Changes in intercompany money pool	—	—	(65)	—	(31)	—	—	—
Dividends paid on common stock	(26)	(43)	(1)	(4)	—	(6)	(1)	(2)
Distributions to member	—	—	—	—	(10)	—	—	—
Contributions from parent/member	—	19	103	237	(299)	(144)	(45)	(110)
Transfer of cash, restricted cash, and cash equivalents to Constellation	2,594	—	—	—	—	—	—	—
Other financing activities	3	(1)	1	1	(8)	(9)	—	2
(Decrease) increase in cash flows from financing activities	\$ (36)	\$ 32	\$ (56)	\$ (51)	\$ (544)	\$ (433)	\$ (12)	\$ (66)

Significant financing cash flow impacts for the Registrants for the three months ended March 31, 2023 and 2022 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 10 — 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 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on debt issuances. Refer to the debt redemptions table 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.
- 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 2022 Form 10-K for additional information on dividend restrictions. See below for quarterly dividends declared.
- Refer to Note 2 — Discontinued Operations for the **transfer of cash, restricted cash, and cash equivalents to Constellation** related to the separation.

Debt

See Note 10 — 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, 2023, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon	SMBC Term Loan Agreement	SOFR plus 0.65%	July 21, 2023	\$ 300
Exelon	US Bank Term Loan Agreement	SOFR plus 0.65%	July 21, 2023	300
Exelon	PNC Term Loan Agreement	SOFR plus 0.65%	July 24, 2023	250
Exelon	Long-Term Software License Agreement	3.70 %	August 9, 2025	6
Exelon	Long-Term Software License Agreement	3.70 %	August 9, 2025	1

Dividends

Quarterly dividends declared by the Exelon Board of Directors during the three months ended March 31, 2023 and for the second quarter of 2023 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share ^(a)
First Quarter 2023	February 14, 2023	February 27, 2023	March 10, 2023	\$ 0.3600
Second Quarter 2023	April 25, 2023	May 15, 2023	June 9, 2023	\$ 0.3600

(a) Exelon's Board of Directors approved an updated dividend policy for 2023. The 2023 quarterly dividend will be \$0.36 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 \$3.2 billion was available to support additional commercial paper as of March 31, 2023, and of which no financial institution has more than 6% 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, 2023 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 10 — 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 2022 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. As of March 31, 2023, Exelon has not issued any shares of common stock under the ATM program and has not entered into any forward sale agreements.

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, 2023 and available credit facility capacity prior to any incremental collateral at March 31, 2023:

	PJM Credit Policy Collateral	Other Incremental Collateral Required ^(a)	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	\$ 17	\$ —	\$ 586
PECO	1	39	455
BGE	3	73	357
Pepco	4	—	300
DPL	4	14	300
ACE	2	—	300

(a) Represents incremental collateral related to natural gas procurement contracts.

Capital Expenditure Spending

As of March 31, 2023, the most recent estimates of capital expenditures for plant additions and improvements for 2023 are as follows:

(In millions)	Transmission	Distribution	Gas	Total ^(a)
Exelon	N/A	N/A	N/A	\$ 7,175
ComEd	500	2,075	N/A	2,550
PECO	75	975	325	1,375
BGE	325	525	475	1,325
PHI	550	1,225	125	1,900
Pepco	250	650	N/A	900
DPL	175	275	125	575
ACE	125	300	N/A	425

(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 \$20 million in 2023. 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 2022 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 10 — 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 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

The credit ratings for Exelon and the Utility Registrants did not change for the three months ended March 31, 2023.

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, 2023, are presented in the following table. Pepco, DPL, and ACE had no activity within the PHI intercompany money pool during the three months ended March 31, 2023.

Exelon Intercompany Money Pool	During the Three Months Ended March 31, 2023		As of March 31, 2023
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	\$ 510	\$ —	\$ 266
PECO	—	(238)	—
BSC	—	(327)	(259)
PHI Corporate	—	(52)	(52)
PCI	45	—	45

Shelf Registration Statements

Exelon and the Utility Registrants have a currently effective combined shelf registration statement, unlimited in amount, that will expire in August 2025. The ability of each Registrant to sell securities off the shelf registration statement 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.

Regulatory Authorizations

The Utility Registrants are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	As of March 31, 2023					
	Short-term Financing Authority			Remaining Long-term Financing Authority		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd	FERC	December 31, 2023	\$ 2,500	ICC	January 1, 2025	\$ 368
PECO	FERC	December 31, 2023	1,500	PAPUC	December 31, 2024	1,125
BGE ^(a)	FERC	December 31, 2023	700	MDPSC	N/A	1,800
Peppo ^(b)	FERC	December 31, 2023	500	MDPSC / DCPSC	December 31, 2025	1,150
DPL ^(b)	FERC	December 31, 2023	500	MDPSC / DEPSC	December 31, 2025	1,075
ACE	NJBPU	December 31, 2023	350	NJBPU	December 31, 2024	625

(a) On December 21, 2022, BGE received approval from the MDPSC for \$1.8 billion in new long-term financing authority with an effective date of January 4, 2023.

(b) The financing authority filed with MDPSC does not have an expiration date, while the financing authority filed with DEPSC has an expiration date of December 31, 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 9 — 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 8 — Retirement Benefits of the 2022 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 10 — 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, or to lock in rate levels on borrowings, which are typically designated as economic hedges. See Note 9 – Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.
- Electric operating revenues risk associated with ComEd's distribution formula rate. ComEd's ROE for its electric distribution service through 2023 is directly correlated to yields on U.S. Treasury bonds. Exelon Corporate may utilize interest rate derivatives to mitigate volatility and manage risk to Exelon, which are typically accounted for as economic hedges. See Note 9 – 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 9 — Derivative Financial Instruments and Note 11 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements.

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 11 — 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.

Commodity derivative contracts ^(a) :	Maturities Within						Total Fair Value
	2023	2024	2025	2026	2027	2028 and Beyond	
Prices based on model or other valuation methods (Level 3)	\$ (20)	\$ (16)	\$ (14)	\$ (12)	\$ (10)	\$ (26)	\$ (98)

(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 2023, 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, 2023, 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 2023 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 2022 Form 10-K, (b) Notes 3 — Regulatory Matters and 18 — Commitments and Contingencies of the 2022 Form 10-K, and (c) Notes 3 — Regulatory Matters and 12 — 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, 2023, the Registrants' risk factors were consistent with the risk factors described in the 2022 Form 10-K in ITEM 1A. RISK FACTORS.

ITEM 5. OTHER INFORMATION

All Registrants

None.

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 relevant 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

<u>Exhibit No.</u>	<u>Description</u>	<u>Location</u>
4-1	Sixth Supplemental Indenture, dated as of February 1, 2023, 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, 2023, Exhibit 4.2

Potomac Electric Power Company

<u>Exhibit No.</u>	<u>Description</u>	<u>Location</u>
4-2	Supplemental Indenture to the Potomac Electric Power Company Mortgage and Deed of Trust, dated as of March 1, 2023	File No. 001-01072, Form 8-K dated March 15, 2023, Exhibit 4.6

Delmarva Power & Light Company

<u>Exhibit No.</u>	<u>Description</u>	<u>Location</u>
4-3	Supplemental Indenture to the Delmarva Power & Light Company Mortgage and Deed of Trust, dated as of March 1, 2023	File No. 001-01405, Form 8-K dated March 15, 2023, Exhibit 4.4

Atlantic City Electric Company

<u>Exhibit No.</u>	<u>Description</u>	<u>Location</u>
4-4	Supplemental Indenture to the Atlantic City Electric Company Mortgage and Deed of Trust, dated as of March 1, 2023	File No. 001-03559, Form 8-K dated March 15, 2023, Exhibit 4.2

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, 2023 filed by the following officers for the following companies:

[Table of Contents](#)

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 Elisabeth J. Graham for Commonwealth Edison Company

PECO Energy Company

Exhibit No.	Description
31-5	Filed by Michael A. Innocenzo for PECO Energy Company
31-6	Filed by Marissa 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 David M. Vahos 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 Phillip S. Barnett 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 Phillip S. Barnett 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 Phillip S. Barnett 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 Phillip S. Barnett 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, 2023 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 Elisabeth J. Graham for Commonwealth Edison Company
PECO Energy Company	
Exhibit No.	Description
32-5	Filed by Michael A. Innocenzo for PECO Energy Company
32-6	Filed by Marissa 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 David M. Vahos 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 Phillip S. Barnett 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 Phillip S. Barnett 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 Phillip S. Barnett 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 Phillip S. Barnett 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)

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.

Calvin G. Butler, Jr.
President, Chief Executive Officer
(Principal Executive Officer) and Director

/s/ JOSEPH R. TRPIK

Joseph R. Trpik
Senior Vice President and Corporate Controller
(Principal Accounting Officer)

/s/ JEANNE M. JONES

Jeanne M. Jones
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

May 3, 2023

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
Gil C. Quiniones
Chief Executive Officer
(Principal Executive Officer) and Director

/s/ ELISABETH J. GRAHAM
Elisabeth J. Graham
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ STEVEN J. CICHOCKI
Steven J. Cichocki
Director, Accounting
(Principal Accounting Officer)

May 3, 2023

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
Carim V. Khouzami
President, Chief Executive Officer
(Principal Executive Officer) and Director

/s/ DAVID M. VAHOS
David M. Vahos
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ JASON T. JONES
Jason T. Jones
Director, Accounting
(Principal Accounting Officer)

May 3, 2023

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

J. Tyler Anthony
President, Chief Executive Officer
(Principal Executive Officer) and Director

/s/ JULIE E. GIESE

Julie E. Giese
Director, Accounting
(Principal Accounting Officer)

/s/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

May 3, 2023

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

J. Tyler Anthony
President, Chief Executive Officer
(Principal Executive Officer) and Director

/s/ JULIE E. GIESE

Julie E. Giese
Director, Accounting
(Principal Accounting Officer)

/s/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer, Treasurer
(Principal Financial Officer) and Director

May 3, 2023

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

J. Tyler Anthony
President, Chief Executive Officer
(Principal Executive Officer) and Director

/s/ JULIE E. GIESE

Julie E. Giese
Director, Accounting
(Principal Accounting Officer)

/s/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

May 3, 2023

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

J. Tyler Anthony
President, Chief Executive Officer
(Principal Executive Officer) and Director

/s/ JULIE E. GIESE

Julie E. Giese
Director, Accounting
(Principal Accounting Officer)

/s/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

May 3, 2023

