

Delmarva Power
PO Box 9239
Newark, DE 19714-9239
800.375.7117

delmarva.com

May 26, 2021

Andrew S. Johnston, Executive Secretary
Maryland Public Service Commission
William Donald Schaefer Tower, 16th Floor
6 St. Paul Street
Baltimore, Maryland 21202-6806

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, 2020 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 2020 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 2020 Annual Report/Maryland Jurisdictional Electric Sales Statistics.
3. One (1) copy of the report of Energy Taxes and Property Taxes paid in 2020 to each municipal, county and state agency in Maryland.
4. One (1) copy of the Exelon First Quarter 2021 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) 231-1571.

Sincerely,

Barbara Temmo, CPA
Manager, External Financial Reporting, Exelon
10 S. Dearborn, Chicago, IL 60603
Barbara.Gbewonyo-Temmo@exeloncorp.com

Enclosures

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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 2020/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q**GENERAL INFORMATION****I. 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.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees 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:

- (1) one million megawatt hours of total annual sales,
- (2) 100 megawatt hours of annual sales for resale,
- (3) 500 megawatt hours of annual power exchanges delivered, or
- (4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: <http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp>. The software is used to submit the electronic filing to the Commission via the Internet.

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

(c) 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

(d) 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:

- a) 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
- b) 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.)

<u>Reference Schedules</u>	<u>Pages</u>
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

- e) 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 _____ for the year ended on which we have reported separately under date of _____, we have also reviewed 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.

- (f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at <http://www.ferc.gov/help/how-to.asp>.

- (g) 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 <http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf> and <http://www.ferc.gov/docs-filing/forms.asp#3Q-gas>.

IV. When to Submit:

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

- a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
- b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. 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

- I. 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.
- II. 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.
- III. 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.
- IV. 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.
- V. 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).
- VI. 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.
- VII. For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.
- VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.
- IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

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

I. 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.

II. 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:

(3) '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;

(4) 'Person' means an individual or a corporation;

(5) '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;

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

(11) "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

(a) 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. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be 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 salt 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).

REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

Document Accession #: 07200408006

File Date: 03/29/2021

IDENTIFICATION		
01 Exact Legal Name of Respondent Delmarva Power & Light Company		02 Year/Period of Report End of <u>2020/Q4</u>
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 (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) / /

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) 03/29/2021
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.

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)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	N/A
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
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	224-225	N/A
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	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	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
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	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
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	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	N/A
64	Hydroelectric Generating Plant Statistics	406-407	N/A
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	N/A

LIST OF SCHEDULES (Electric Utility) (continued)

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)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	N/A
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	<p>Stockholders' Reports Check appropriate box:</p> <p><input type="checkbox"/> Two copies will be submitted</p> <p><input type="checkbox"/> No annual report to stockholders is prepared</p>		

Name of Respondent Document Accession #: 20210329-8006 Delmarva Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 03/29/2021 / /	Year/Period of Report End of <u>2020/Q4</u>
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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
701 Ninth Street, N.W.
Washington, DC 20068

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.

Incorporated under the laws of the State of Delaware, April 22, 1909 and the Commonwealth of Virginia, December 31, 1979.

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.

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...Enter the date when such independent accountant was initially engaged:
- (2) No

Name of Respondent Document Accession #: 20210329-8006 Delmarva Power & Light Company	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 <u>2020/Q4</u>
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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, 2020, Delmarva Power & Light Company 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. For additional information, see the Exelon Corporation Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2020.

CORPORATIONS CONTROLLED BY RESPONDENT

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

Definitions

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

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

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President and Chief Executive Officer	Velazquez, David M.	621,366
2	Sr. Vice President and Chief Operating Officer	Anthony, J. Tyler	422,300
3	Sr. Vice President, Chief Financial Officer & Treasurer	Barnett, Phillip S.	404,034
4	Sr. Vice President, Governmental & External Affairs	Lavinson, Melissa	395,906
5	Sr. Vice President, Legal and Regulatory Strategy	Stark, Wendy E.	346,450
6	and General Counsel		
7	Sr. Vice President, Customer Operations	Dickens, Derrick	300,000
8	Vice President, Regulatory Policy and Strategy	McGowan, Kevin M.	330,000
9	Corporate Secretary	O'Neill, Thomas S.	538,125
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13	Listed officers are employees of PHI Service Company		
14	or Exelon Business Services Company LLC; salary for		
15	year represents the executive's annual base salary		
16	as of December 31, 2020 and only a portion of their		
17	annual base salary is allocated to DPL.		
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Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 7 Column: a

Effective January 1, 2020, Derrick Dickens was elected to the role of Sr. Vice President, Customer Operations.

Schedule Page: 104 Line No.: 9 Column: a

Effective December 31, 2020, Thomas O'Neill resigned from his role as Corporate Secretary. Mr. O'Neill earned \$538,125 in 2019.

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Butler, Calvin G., Chairman ***	701 Ninth Street, N.W., Washington, D.C. 20068
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3	Velazquez, David M., Chief Executive Officer	701 Ninth Street, N.W., Washington, D.C. 20068
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

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	FERC Proceeding
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-9A of PJM OATT	ER20-2198, Cost Revenue Alignment
9		
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Name of Respondent Delmarva Power & Light Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 03/29/2021	Year/Period of Report End of 2020/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

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20200515-5178	05/15/2020	ER09-1158	Informational Filing of Annual Formula	
2					
3					
4					
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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).	Schedule	Column	Line No
1		Not Applicable		
2				
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Name of Respondent Delmarva Power & Light Company	Document Accession #: 20210329-8006	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report Filed Date: 03/29/2021	Year/Period of Report End of 2020/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.

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

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

IMPORTANT CHANGES DURING THE QUARTER/YEAR

This information is for changes in the year ended December 31, 2020.

Item 1	None
Item 2	None
Item 3	None
Item 4	None
Item 5	None
Item 6	Refer to Note 10, "Debt and Credit Agreements" of the accompanying "Notes to the Financial Statements" and back schedule pages 256 - 257 for a discussion of DPL's debt. The authorizations for the issuances of long-term debt are Delaware Public Service Commission (DPSC) order number 9525 and Maryland Public Service Commission (MDPSC) order number 89457. 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 ES20-4-000.
Item 7	None
Item 8	None
Item 9	Refer to Note 12, "Commitments and Contingencies" of the accompanying "Notes to Financial Statements" for a discussion of DPL's legal proceedings
Item 10	None
Item 11	"Reserved"
Item 12	"Not Applicable"
Item 13	See Officers page (Page 104) and Directors page (Page 105) for details concerning changes in the respondent's officers during 2020.
Item 14	DPL participates in a cash management program. As of December 31, 2020, DPL's proprietary capital ratio is greater than 30 percent.

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)	200-201	5,721,801,010	5,371,631,253
3	Construction Work in Progress (107)	200-201	163,907,674	125,378,143
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,885,708,684	5,497,009,396
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,574,752,836	1,477,597,220
6	Net Utility Plant (Enter Total of line 4 less 5)		4,310,955,848	4,019,412,176
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		4,310,955,848	4,019,412,176
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		13,968,767	13,968,767
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,488,907	4,430,033
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		473,822	475,049
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		9,953,682	10,013,783
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		15,331,860	12,448,546
36	Special Deposits (132-134)		488	305
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		843	329,194
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		116,423,491	91,803,458
41	Other Accounts Receivable (143)		66,784,660	40,230,363
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		30,210,469	14,626,712
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		1,376,155	122,848
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	50,993,734	44,642,941
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	9,751,967	8,787,093

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

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)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		4,906,107	6,872,547
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		1,255,416	1,609,136
57	Prepayments (165)		11,870,726	18,471,567
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		523	45,208
60	Rents Receivable (172)		1,522,391	1,031,368
61	Accrued Utility Revenues (173)		61,873,231	61,127,012
62	Miscellaneous Current and Accrued Assets (174)		1,556,557	1,741,870
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		313,437,680	274,636,744
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		12,339,832	12,414,416
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	177,685,017	176,322,478
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	168,388,483	173,825,745
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		5,331,985	5,464,330
82	Accumulated Deferred Income Taxes (190)	234	198,485,231	198,093,922
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		562,230,548	566,120,891
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,196,577,758	4,870,183,594

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)	250-251	2,250	2,250
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		537,612,396	537,612,396
7	Other Paid-In Capital (208-211)	253	561,182,049	448,555,442
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	9,924,450	9,924,450
11	Retained Earnings (215, 215.1, 216)	118-119	584,379,203	602,118,249
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,177,779	-2,177,779
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		1,671,073,669	1,576,186,108
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,657,230,000	1,557,230,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	10,000,000	10,000,000
22	Unamortized Premium on Long-Term Debt (225)		2,147,780	2,634,428
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,331,025	1,380,567
24	Total Long-Term Debt (lines 18 through 23)		1,668,046,755	1,568,483,861
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		17,592,040	8,620,632
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		6,613,991	5,850,520
29	Accumulated Provision for Pensions and Benefits (228.3)		17,302,679	18,514,393
30	Accumulated Miscellaneous Operating Provisions (228.4)		230,701	276,213
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		14,296,727	11,870,625
35	Total Other Noncurrent Liabilities (lines 26 through 34)		56,036,138	45,132,383
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		146,094,951	55,995,943
38	Accounts Payable (232)		111,564,716	99,578,447
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		35,912,097	32,398,374
41	Customer Deposits (235)		32,433,474	35,555,431
42	Taxes Accrued (236)	262-263	18,090,528	14,107,560
43	Interest Accrued (237)		6,514,228	7,742,554
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

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)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		398,676	414,358
48	Miscellaneous Current and Accrued Liabilities (242)		44,796,369	41,201,993
49	Obligations Under Capital Leases-Current (243)		2,884,295	1,432,227
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		398,689,334	288,426,887
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		9,575,635	7,907,288
57	Accumulated Deferred Investment Tax Credits (255)	266-267	1,691,783	2,004,132
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	33,935,898	22,840,731
60	Other Regulatory Liabilities (254)	278	445,224,945	507,596,758
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		807,017,637	754,148,951
64	Accum. Deferred Income Taxes-Other (283)		105,285,964	97,456,495
65	Total Deferred Credits (lines 56 through 64)		1,402,731,862	1,391,954,355
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,196,577,758	4,870,183,594

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.

2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.

3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.

4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.

5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)

6. 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.

7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,274,167,663	1,319,054,785		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	770,724,934	793,197,500		
5	Maintenance Expenses (402)	320-323	100,216,602	71,766,942		
6	Depreciation Expense (403)	336-337	144,808,453	138,436,455		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	10,902,394	6,751,967		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	1,854,015	1,853,960		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		17,854,301	24,821,486		
13	(Less) Regulatory Credits (407.4)		7,478,961			
14	Taxes Other Than Income Taxes (408.1)	262-263	63,632,345	56,061,850		
15	Income Taxes - Federal (409.1)	262-263	-9,682,605	29,384,121		
16	- Other (409.1)	262-263	23,117	6,940		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	78,767,681	61,390,832		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	89,682,789	68,440,831		
19	Investment Tax Credit Adj. - Net (411.4)	266	-312,349	-346,468		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,081,627,138	1,114,884,754		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		192,540,525	204,170,031		

STATEMENT OF INCOME FOR THE YEAR (Continued)

- 9. Use page 122 for important notes regarding the statement of income for any account thereof.
- 10. 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.
- 11 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 purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
- 12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
- 13. 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.
- 14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
- 15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
1,112,857,783	1,151,304,259	161,309,880	167,750,526			2
						3
657,904,925	675,517,798	112,820,009	117,679,702			4
90,125,736	65,081,265	10,090,866	6,685,677			5
132,977,671	127,027,779	11,830,782	11,408,676			6
						7
9,531,671	5,834,311	1,370,723	917,656			8
1,854,015	1,853,960					9
						10
						11
17,329,040	23,230,251	525,261	1,591,235			12
6,777,714		701,247				13
53,090,210	46,561,814	10,542,135	9,500,036			14
-9,843,406	25,933,274	160,801	3,450,847			15
20,805	6,246	2,312	694			16
70,291,631	54,211,552	8,476,050	7,179,280			17
79,792,925	61,168,812	9,889,864	7,272,019			18
-272,039	-305,466	-40,310	-41,002			19
						20
						21
						22
						23
						24
936,439,620	963,783,972	145,187,518	151,100,782			25
176,418,163	187,520,287	16,122,362	16,649,744			26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		192,540,525	204,170,031		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		2,789,645	3,428,980		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		3,717,668	3,056,289		
33	Revenues From Nonutility Operations (417)		4,001	67,614		
34	(Less) Expenses of Nonutility Operations (417.1)		102,971	470,328		
35	Nonoperating Rental Income (418)		210,430	3,145,995		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		107,394	432,921		
38	Allowance for Other Funds Used During Construction (419.1)		4,233,116	3,978,538		
39	Miscellaneous Nonoperating Income (421)		1,206,155	1,414,392		
40	Gain on Disposition of Property (421.1)		-88,205			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		4,641,897	8,941,823		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			10,561		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		755,581	707,166		
46	Life Insurance (426.2)					
47	Penalties (426.3)		138,619	253,177		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		804,034	560,611		
49	Other Deductions (426.5)		14,258,167	2,510,225		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		15,956,401	4,041,740		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	733,497	688,279		
53	Income Taxes-Federal (409.2)	262-263	-3,345,733	-587,347		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	347,771	3,378,163		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,354,226	2,493,219		
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)		-3,618,691	985,876		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-7,695,813	3,914,207		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		60,359,414	58,827,558		
63	Amort. of Debt Disc. and Expense (428)		1,094,358	981,675		
64	Amortization of Loss on Reaquired Debt (428.1)		1,036,627	1,041,847		
65	(Less) Amort. of Premium on Debt-Credit (429)		486,649	469,320		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		73,849	175,224		
68	Other Interest Expense (431)		1,482,023	2,092,127		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,075,864	1,961,867		
70	Net Interest Charges (Total of lines 62 thru 69)		61,483,758	60,687,244		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		123,360,954	147,396,994		
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)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		123,360,954	147,396,994		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Delmarva Power & Light Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 114 Line No.: 40 Column: c

Debit balance in Account 421.1 due to creation of Regulatory Liability to refund a prior year gain on asset sale to customers under DPL MD Case No. 9630.

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of 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 in 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, include them on pages 122-123.

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		602,118,249	593,221,255
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		123,360,954	147,396,994
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-141,100,000	(138,500,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-141,100,000	(138,500,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		584,379,203	602,118,249
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of 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 in 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, include them on pages 122-123.

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)
41				
42				
43				
44				
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)		584,379,203	602,118,249
	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				
53	Balance-End of Year (Total lines 49 thru 52)		-2,177,779	(2,177,779)

Document Accession #: 20210329-80026 Submission Date: 03/29/2021

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	123,360,954	147,396,994
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	144,808,453	138,436,455
5	Amortization of regulatory debits/credits and limited plant	21,277,734	31,573,453
6	Plant Acquisition	1,854,015	1,853,960
7	Unamortized Discount (Premium) on Long-Term Debt	1,641,159	1,510,581
8	Deferred Income Taxes (Net)	-11,921,563	-6,177,392
9	Investment Tax Credit Adjustment (Net)	-312,349	-346,468
10	Net (Increase) Decrease in Receivables	-37,197,398	-3,244,301
11	Net (Increase) Decrease in Inventory	-4,030,633	-7,047,439
12	Net (Increase) Decrease in Allowances Inventory	-964,874	-683,773
13	Net Increase (Decrease) in Payables and Accrued Expenses	3,660,695	265,450
14	Net (Increase) Decrease in Other Regulatory Assets	-11,737,879	-4,489,710
15	Net Increase (Decrease) in Other Regulatory Liabilities	9,856,596	-26,419,341
16	(Less) Allowance for Other Funds Used During Construction	4,233,116	3,978,538
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Pension	9,318,701	15,037,502
19	Other Operating Activities	23,773,683	275,081
20	Net Increase (Decrease) in Interest & Taxes Accrued	1,653,713	9,854,695
21	(Gain) Loss on Sales of Assets	-9,079	10,561
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	270,798,812	293,827,770
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-428,488,402	-351,956,277
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	-4,233,116	-3,978,538
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-424,255,286	-347,977,739
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
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	Associated and Subsidiary Companies		
43	Proceeds from sale of assets	12,400	
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
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	Net (Increase) Decrease in Restricted Cash	-183	1,100,269
54	Other Investing Activities	-3,933,761	8,263
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-428,176,830	-346,869,207
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	178,400,000	75,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	90,099,008	55,995,943
67	Other (provide details in footnote):		
68	Capital Contribution from Parent	112,626,607	62,658,502
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	381,125,615	193,654,445
71	Cost of Issuances	-1,692,634	-641,300
72	Payments for Retirement of:		
73	Long-term Debt (b)	-78,400,000	-12,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-141,100,000	-138,500,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	159,932,981	42,513,145
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	2,554,963	-10,528,292
87			
88	Cash and Cash Equivalents at Beginning of Period	12,777,740	23,306,032
89			
90	Cash and Cash Equivalents at End of period	15,332,703	12,777,740

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 19 Column: b

Other Operating Activities:

	2020	2019
Net decrease (increase) in Prepayments	\$ 6,600,841	\$ (990,853)
Net (increase) decrease in Miscellaneous long term assets and deferred debits	(2,304,577)	544,788
Net increase in Other deferred credits	9,994,238	1,502,976
Principal Portion of Capital Lease Payments	(3,748,145)	—
Asset Write-Offs	6,919,619	—
Other	6,311,707	(781,830)
Total Other Operating Activities	\$ 23,773,683	\$ 275,081

Schedule Page: 120 Line No.: 54 Column: b

Other Investing Activities:

	2020	2019
Re-capitalized Fleet Depreciation	\$ 1,264,063	\$ 1,272,562
Other	(5,197,824)	(1,264,299)
Total Other Investing Activities	\$ (3,933,761)	\$ 8,263

Name of Respondent Delmarva Power & Light Company Document Accession #: 20210329-8006	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report Filed Date: 03/29/2021	Year/Period of Report End of 2020/Q4
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NOTES TO FINANCIAL STATEMENTS

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

PAGE 122 INTENTIONALLY LEFT BLANK
 SEE PAGE 123 FOR REQUIRED INFORMATION.

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

The notes presented herein were derived from the notes disclosed within the Annual Report of the Exelon Corporate (Exelon) on Form 10-K for the period ending December 31, 2020. 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 northern Delaware.

Basis of Presentation

DPL is an indirect, wholly owned, subsidiary of Exelon Corporation (Exelon).

Accounting policies for regulated operations are in accordance with those prescribed by the regulatory authorities having jurisdiction, principally the Federal Energy Regulatory Commission (FERC) under various federal laws. The accompanying financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in the Uniform System of Accounts (USOA) and accounting releases, which differ from accounting principles generally accepted in the United States (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 single 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.

The accompanying financial statements as of December 31, 2020 and 2019 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, 2019 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, 2019 FERC Form No. 1 "Annual Report of Major Electric Utilities, Licensees and Others" (FERC Form No. 1).

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 their 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. In addition, DPL has updated its existing business continuity plans.

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. Management assessed certain

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

accounting matters that require consideration of forecasted financial information, including, but not limited to, our accumulated provision for uncollectible accounts and our carrying value of other long-lived assets, in context with the information reasonably available to us and the unknown future impacts of COVID-19 as of December 31, 2020 and through the date of this report. DPL's future assessment of our current expectations of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts to its financial statements in future reporting periods.

Use of Estimates

The preparation of financial statements in conformity with USOA and GAAP 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 other asset retirement obligations (AROs), pension and other postretirement employee benefits (OPEB), inventory reserves, accumulated provision for uncollectible accounts, goodwill and asset impairment assessments, derivative instruments, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Accounting for the Effects of Regulation

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 Maryland Public Service Commission (MDPSC) and the Delaware Public Service Commission (DPSC), 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 consolidated 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 energy commodities and related products and services, utility revenues from alternative revenue programs (ARP), and realized and unrealized revenues recognized under mark-to-market energy commodity derivative contracts. 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 MDPSC in accordance with its revenue decoupling mechanisms. DPL

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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. See Note 2 - Regulatory Matters for additional information.

Option Contracts, Swaps, and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. To the extent DPL receives full cost recovery for energy procurement and related costs from retail customers, it records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability in its Balance Sheet. See Note 2 — Regulatory Matters and Note 9 — Derivative Financial Instruments 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 utility taxes that are presented on a gross basis.

Income Taxes

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

Cash and Cash Equivalents

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

Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2020, and 2019, DPL's restricted cash and cash equivalents primarily represented funds restricted for the collateral held from energy suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets.

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

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 risk 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.

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.

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, materials and supplies, and emissions allowances are generally included in inventory when purchased. Fossil fuel and emissions allowances are expensed to purchased power and fuel expense when used or sold. Materials and supplies generally includes transmission, distribution and generating plant 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. DPL also includes 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, including planned major maintenance activities 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. United States Department of Energy (DOE) smart grid investment grant (SGIG) and other funds reimbursed to DPL have been accounted for as CIAC.

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. 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. On

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

June 30, 2020, FERC issued an order allowing for a 12-month waiver of certain provisions in order to modify the AFUDC rate calculation beginning March 1, 2020, in response to the COVID-19 pandemic. DPL has elected the waiver which did not have a significant impact on its financial statements.

See Note 5 - Property, Plant, and Equipment and Note 14 - Supplemental Financial Information 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, composite or unitary 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, historical retirements, site licenses and management estimates of operating costs and expected future energy market conditions.

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. With the exception of the regulatory assets and liabilities discussed above, when the recovery period is more than one year, the amortization is generally recorded to Depreciation and amortization in DPL's Statement of Income.

See Note 2 - Regulatory Matters and Note 14 - Supplemental Financial Information for additional information regarding the amortization of DPL's regulatory assets.

Asset Retirement Obligations

AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Statement of Income or, in the case of DPL's accretion, 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 market 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.

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Asset Impairments

Long-Lived Assets. DPL regularly monitors and evaluates the carrying value of long-lived assets and asset groups 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 a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. DPL determines if long-lived assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value.

Derivative Financial Instruments

All 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. Changes in fair value may be recorded as a regulatory asset or liability if there is an ability to recover or return the associated costs. 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 each transaction.

NPNS are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as NPNS are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See 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.

New Accounting Pronouncements

New Accounting Standards Adopted as of January 1, 2020

The following new authoritative accounting guidance issued by the FASB was adopted as of January 1, 2020 and will be reflected by the Registrants in their consolidated financial statements beginning in the first quarter of 2020.

Impairment of Financial Instruments (Issued June 2016). Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments, and net

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects its current estimate of uncollectible accounts expected to be incurred over the life of the financial instrument based on historical experience, current conditions, and reasonable and supportable forecasts. The standard was effective January 1, 2020 and requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. This standard is primarily applicable to DPL's trade accounts receivables balances. The guidance did not have a significant impact on DPL's financial statements.

Goodwill Impairment (Issued January 2017). Simplifies the accounting for goodwill impairment by removing Step 2 of the current impairment assessment model, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment assessment). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. The standard was effective January 1, 2020 and must be applied on a prospective basis. DPL does not have goodwill as of December 31, 2020 and this updated guidance did not impact DPL's financial statements.

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 2020.

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
DPL - Maryland	December 5, 2019 (amended April 23, 2020)	Electric	\$ 17	\$ 12	9.6%	July 14, 2020	July 16, 2020
DPL - Delaware	February 21, 2020 (amended October 9, 2020)	Natural Gas	7	2	9.6%	January 6, 2021	September 21, 2020

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
DPL - Delaware(a)	March 6, 2020 (amended February 2, 2021)	Electric	\$ 23	10.3%	Third quarter of 2021

(a) The rates went into effect on October 6, 2020, subject to refund.

Transmission Formula Rates

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Transmission Formula Rate. 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 (initial year revenue requirement). The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year (annual reconciliation).

For 2020, the following total decreases were included in DPL's electric transmission formula rate update:

Registrant(a)	Initial Revenue Requirement Decrease	Annual Reconciliation Decrease	Total Revenue Requirement Decrease(b)	Allowed Return on Rate Base(c)	Allowed ROE(d)
DPL	\$ (4)	\$ (40)	\$ (44)	7.20%	10.50%

- (a) Rate is effective June 30, 2020 - May 31, 2021, subject to review by interested parties pursuant to review protocols of DPL's tariff.
- (b) DPL's transmission revenue requirement includes a decrease related to the April 24, 2020 settlement agreement related to excess deferred income taxes. Refer to Transmission-Related Income Tax Regulatory assets below for additional information.
- (c) Represents the weighted average debt and equity return on transmission rate bases.
- (d) As part of the FERC-approved settlement of the Return on Equity (ROE) complaint against DPL, the rate of return on common equity is 10.50%, inclusive of a 50-basis-point incentive adder for being a member of a Regional Transmission Organization (RTO).

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

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2020 and December 31, 2019:

Regulatory Assets (Account 182.3)	December 31, 2020	December 31, 2019
Advanced Metering Infrastructure (AMI) programs - deployment costs	\$ 30	\$ 35
AMI programs - legacy meters	24	27
Electric energy and natural gas costs	6	10
Transmission formula rate annual reconciliations	2	2
Energy efficiency and demand response programs	82	75
Deferred storm costs	4	3
COVID-19	7	—
Other	23	24
Total regulatory assets	<u>\$ 178</u>	<u>\$ 176</u>

Regulatory Liabilities (Account 254)	December 31, 2020	December 31, 2019
Deferred income taxes	\$ 404	\$ 477
Electric energy and natural gas costs	11	13
Transmission formula rate annual reconciliations	9	—
COVID-19	3	—
Other	18	18
Total regulatory liabilities	<u>\$ 445</u>	<u>\$ 508</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 that are recoverable	Over the period in which the related deferred income taxes reverse, which	

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Deferred Income Taxes	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 separate from the transmission formula rate. See Transmission-Related Income Tax Regulatory Assets section above for additional information.	is generally based on the expected life of the underlying assets. For TCJA, generally refunded over the remaining depreciable life of the underlying assets, except in certain jurisdictions where the commissions have approved a shorter refund period for certain assets not subject to IRS normalization rules.	No
AMI programs - deployment costs	Installation costs of new smart meters, including implementation costs of dynamic pricing for energy usage resulting from smart meters.	2030	Yes
AMI programs - legacy meters	Early retirement costs of legacy meters.	2030	Delaware - Yes
Electric energy and natural gas costs	Under (over)-recoveries related to energy and gas supply related costs recoverable (refundable) under approved rate riders.	2025	Maryland - No Delaware - Yes
Transmission formula rate annual reconciliations	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.	2022	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.	2035	Yes
Merger integration costs	Integration costs to achieve distribution synergies related to the PHI acquisition.	2026	Yes
Under (over)-recovered revenue decoupling	Electric and / or gas distribution costs recoverable from or (refundable) to customers under decoupling mechanisms.	2021	No
Deferred Storm Costs	Amounts represent total incremental storm restoration costs incurred due to major storm events recoverable from customers in the Maryland jurisdiction.	\$2 million - 2025; \$2 million not currently being recovered	Yes
COVID-19	See COVID-19 section below for detail on the COVID-19 regulatory asset.	Not currently being recovered.	No

COVID-19. Starting in March of 2020, DPL temporarily suspended customer disconnections for non-payment and temporarily ceased new late payment fees for all customers and restored services to customers upon request who were disconnected in the last twelve months. The duration and extent of these measures varies by jurisdiction. These measures are no longer in place for Delaware and Maryland as of December 31, 2020.

Typically, DPL recovers uncollectible accounts expense through distribution base rate cases; however, during the second quarter of 2020, the MDPSC and DPSC issued orders authorizing the creation of regulatory assets to track incremental COVID-19 related costs. In addition to uncollectible accounts expense, DPL has also incurred direct costs related to COVID-19 consisting primarily of costs to

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of their employees.

DPL has recorded a regulatory asset for the impacts of COVID-19 reflecting primarily incremental uncollectible accounts expense and direct costs, partially offset by a decrease in travel costs. Refer to the Regulatory assets table above for amounts as of December 31, 2020. DPL expects to seek recovery of these costs, net of travel cost savings, in upcoming distribution base rate cases.

Capitalized Ratemaking Amounts Not Recognized

As of both December 31, 2020 and 2019, DPL had \$3 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 Sheets. 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 the entities expect 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.

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

- (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 (242) and Other Deferred Credits (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 as shown in the table below. 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, 2020 and 2019.

Balance at December 31, 2019	\$ —
Consideration received or due	12
Revenues recognized	—
Balance at December 31, 2020	<u>\$ 12</u>

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, 2020 through the remainder of the 35-year term.

2021	2022	2023	2024	2025 and thereafter	Total
\$ 1	\$ 1	\$ 1	\$ —	\$ 9	\$ 12

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

4. Account Receivable

Accumulated Provision for Uncollectible Accounts

The following table presents the rollforward of Accumulated Provision for Uncollectible Accounts on Customer Accounts Receivable.

	For the Year Ended December 31, 2020
Balance as of December 31, 2019	\$ 11
Plus: Current Period Provision for Uncollectible Accounts (a)	15
Less: Write-offs, net of recoveries (b)	4
Balance as of December 31, 2020	<u>\$ 22</u>

(a) The increase is primarily as a result of increased aging of receivables, the temporary suspension of customer disconnections for non-payment, temporary cessation of new late payment fees, and reconnection of service to customers previously disconnected due to COVID-19.

(b) Recoveries were not material to DPL.

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

	For the Year Ended December 31, 2020
Balance as of December 31, 2019	\$ 4
Plus: Current Period Provision for Uncollectible Accounts	5
Less: Write-offs, net of recoveries (a)	—
Balance as of December 31, 2020	<u>\$ 9</u>

(a) Recoveries were not material to DPL.

Accrued Utility Revenues

DPL accrued \$62 million and \$61 million of unbilled revenues as of December 31, 2020 and December 31, 2019, respectively, in Account 173, Accrued Utility Revenues.

Purchase of Customer and Other Accounts Receivable

DPL is required under legislation and regulations in Maryland, to purchase certain receivables from alternative retail electric and natural gas suppliers that participate in its consolidated billing. DPL had \$207 million of Receivables Purchased as of December 31, 2020, which includes \$13 million of Receivables Purchased from Exelon Generation Company, LLC (Generation), a related party of DPL.

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	5-70

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Gas - transportation and distribution	5-75
Common - electric and gas	5-75
Other property, plant and equipment	8-50

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

Annual Depreciation Rates	December 31,	
	2020	2019
Electric - transmission and distribution	2.85 %	2.86 %
Gas - transportation and distribution	1.50 %	1.55 %
Common - electric and gas	6.72 %	6.24 %

The credits to AFUDC debt and equity were \$6 million for both the years ended December 31, 2020 and 2019, 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 plants and transmission facilities at December 31, 2020 and 2019 were as follows:

Operator	PSEG/DPL	
DPL's share at December 31, 2020	NJ/DE(a)	
Plant in service	\$	3
Accumulated depreciation		2
DPL's share at December 31, 2019	NJ/DE(a)	
Plant in service	\$	2
Accumulated depreciation		1

(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.

See Note 1 - Significant Accounting Policies for additional information regarding property, plant and equipment policies. See 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 ("PCBs"). 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 Balance Sheets from January 1, 2019 to December 31, 2020:

ARO's at January 1, 2019	\$	11
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Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Net increase due to changes in, and timing of, estimated future cash flows	1
AROs at December 31, 2019 (Account 230)	12
Net increase due to changes in, and timing of, estimated future cash flows	2
AROs at December 31, 2020 (Account 230)	<u>\$ 14</u>

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 Year Ended December 31,	
	2020	2019
Included in operations:		
Federal		
Current	\$ (13)	\$ 29
Deferred	(20)	(21)
State		
Current	—	—
Deferred	8	14
Total	<u>\$ (25)</u>	<u>\$ 22</u>

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 Year Ended December 31,	
	2020(a)(b)	2019(a)
U.S. Federal statutory rate	21.0 %	21.0 %
Increase (decrease) due to:		
State income taxes, net of Federal income tax benefit	6.6	6.8
Amortization of investment tax credit, including deferred taxes on basis difference	(0.3)	(0.2)
Plant Basis differences	(0.4)	(0.4)
Production tax credits and other credits	(0.3)	—
Excess deferred tax amortization	(51.7)	(14.2)
Other	0.1	—
Effective income tax rate	<u>(25.0)%</u>	<u>13.0 %</u>

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

- (a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
- (b) At DPL, the negative effective tax rate is primarily attributable to accelerated amortization of transmission related income tax regulatory liabilities as a result of regulatory settlements. See Note 2 — Regulatory Matters for additional information.

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, 2020 and 2019 are presented below:

	As of December 31,	
	2020	2019
Plant basis differences	\$ (806)	\$ (753)
Deferred pension and postretirement obligation	(40)	(42)
Deferred debt refinancing costs	(1)	(2)
Regulatory assets and liabilities	67	88
Tax loss carryforward	49	44
Other, net	17	11
Deferred income tax liabilities, net (Accounts 190, 282, 283)	\$ (714)	\$ (654)
Unamortized investment tax credits (Account 255)	(2)	(2)
Total deferred income tax liabilities (net) and unamortized investment tax credits	(716)	(656)

The following table provides DPL's carryforwards, which are presented on a post-apportioned basis, as of December 31, 2020. Note, there were no Federal carryforwards.

State net operating losses	\$	728
Deferred taxes on state tax attributes (net)	\$	49
Year in which net operating loss carryforwards will begin to expire		2032

Tabular Reconciliation of Unrecognized Tax Benefits

The following tables presents changes in DPL's unrecognized tax benefits as of December 31, 2020 and 2019.

Unrecognized tax benefits at January 1, 2020	\$	1
Change to positions that only affect timing		—
Increases based on tax positions prior to 2020		—
Decreases based on tax positions prior to 2020		—
Unrecognized tax benefits at December 31, 2020	\$	1
Unrecognized tax benefits at January 1, 2019	\$	—
Change to positions that only affect timing		1
Increases based on tax positions prior to 2019		—
Decreases based on tax positions prior to 2019		—

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Unrecognized tax benefits at December 31, 2019

\$ 1

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, 2020 and 2019.

DPL's unrecognized tax benefits that, if recognized, may be included in future base rates and that portion would have no impact on the effective tax rate are not material as of December 31, 2020 and 2019.

Total amounts of interest and penalties recognized

DPL's net interest and penalties receivable (payable) related to tax positions are not material at both December 31, 2020 and 2019.

DPL's interest and penalty expense related to tax positions are not material at both December 31, 2020 and 2019.

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

	<u>Open Years</u>
Federal consolidated income tax returns ^(a)	2010-2019
Delaware separate corporate income tax returns	2010-2019
Maryland separate company corporate net income tax returns	2010-2019

(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 changes in 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, 2020 and 2019.

Allocation of Tax Benefits

DPL is party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net federal and state benefits attributable to Exelon is reallocated to DPL and the other Registrants.

DPL's federal tax benefit allocation from Exelon under the Tax Sharing Agreement was \$6 million and \$1 million as of December 31,

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

2020 and 2019, respectively.

8. Retirement Benefits

Exelon sponsored defined benefit pension plans and OPEB plans for essentially all current employees. The table below shows the pension and OPEB plans in which DPL employees participated at December 31, 2020.

Name of Plan(a):

Qualified Pension Plans:

- Exelon Corporation Retirement Program(b)
- Pension Plan of Constellation Energy Group, Inc.(c)
- Pepco Holdings LLC Retirement Plan(d)

Non-Qualified Pension Plans:

- Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan(d)
- Conectiv Supplemental Executive Retirement Plan(d)

OPEB Plans:

- PECO Energy Company Retiree Medical Plan(b)
- Pepco 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 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 postretirement benefit plan costs, which were included in Operating and maintenance expense within its Statements of Income and capital expenditures within its Balance Sheets for the years ended December 31, 2020 and 2019.

	2020	2019
Pension and OPEB	\$ 7	\$ 15

Contributions

The following table provide DPL's contributions to the pension and OPEB plans for the years ended December 31, 2020 and 2019:

	2020	2019
Pension	\$ —	\$ 1

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

OPEB \$ — \$ —

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 levelized annual contributions with the objective of achieving 100% funded status on an accumulated benefit obligation basis over time. Unlike the qualified pension plans, non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

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

The following table provides DPL's planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to OPEB plans in 2021:

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
2021	\$ —	\$ 1	\$ —

Defined Contribution Savings Plan

DPL participates in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the Internal Revenue Code and allow employees to contribute a portion of their pre-tax and 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 matching contributions to the savings plans during the years ended December 31, 2020 and 2019.

	2020	2019
Savings Plan Matching Contributions	\$ 3	\$ 3

9. Derivative Financial Instruments

DPL uses derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations.

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 derivative settles and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed.

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referenced contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default.

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 risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options, and short-term and long-term commitments to purchase and sell energy and commodity products. DPL believes these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

DPL procures electric and natural gas supply through a competitive procurement process approved by the MDPSC and the DPSC. 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, 2020 and 2019.

As of December 31, 2020 and 2019, DPL had no fair value balances associated with derivatives on its Balance Sheet.

Proprietary Trading (Commodity Price Risk)

DPL does not execute derivatives for proprietary trading purposes.

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.

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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, 2020, DPL's counterparty credit risk with suppliers was not material.

Credit-Risk-Related Contingent Features

DPL's electric supply procurement contracts do not contain provisions that would require it 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, 2020, DPL was not required to post collateral for any of these agreements. If DPL lost its investment grade credit rating as of December 31, 2020, it could have been required to post incremental collateral to its counterparties of \$9 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 at December 31, 2020 and 2019:

Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
2020(a)(b)	2019(a)(b)	2020	2019	2020	2019
\$ 300	\$ 300	\$ 146	\$ 56	0.24 %	2.02 %

(a) At December 31, 2020, excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of \$8 million. These facilities expire on October 8, 2021. These facilities are solely utilized to issue letters of credit. At December 31, 2019, excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of \$8 million.

(b) DPL's revolving credit facility has the ability to flex to \$500 million. 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 Potomac Electric Power Company (PEPCO), DPL or Atlantic City Electric Company (ACE) may not exceed \$900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.

In 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

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

then available capacity under its credit facility.

At December 31, 2020, DPL had the following aggregate bank commitments, credit facility borrowings and available capacity under its credit facilities:

Facility Type	Aggregate Bank Commitment ^(b)	Facility Draws	Outstanding Letters of Credit	Available Capacity at December 31, 2020	
				Actual	To Support Additional Commercial Paper
Syndicated Revolver ^(a)	\$ 300	\$ —	\$ —	\$ 300	\$ 154

(a) On May 26, 2018, DPL's syndicated revolving credit facilities had its maturity date extended to May 26, 2023.

(b) Excludes credit facility agreements arranged at minority and community banks with an aggregate commitment of \$8 million. These facilities expire on October 8, 2021. 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 LIBOR-based rate, plus an adder based upon its credit rating. The adder for the prime based borrowings is 0 basis points and for the LIBOR-based borrowings is 100 basis points. If DPL loses its investment grade rating, the maximum adders for prime rate borrowings and LIBOR-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 (VRDB). VRDBs are subject to repayment on the demand of the holders. These bonds may be converted to a fixed-rate, fixed-term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, DPL views VRDBs as a source of long-term financing. As of both December 31, 2020 and 2019, \$79 million in VRDBs issued by DPL were outstanding and are included in Long-term debt on its Balance Sheets.

Long-Term Debt

The following table presents DPL's outstanding long-term debt as of December 31, 2020 and 2019:

	Rates	Maturity Date	December 31,	
			2020	2019
Long-term debt				
First mortgage bonds (Account 221) ^(a)	0.19% - 4.27%	2023 - 2049	\$ 1,624	\$ 1,445
Unsecured tax-exempt bonds (Account 221)	0.17% - 0.20%	2024	33	112
Medium-terms notes (unsecured) (Account 224)	7.72%	2027	10	10
Finance leases (Accounts 227 and 243)	3.54%	2025-2028	21	10
Total long-term debt			\$ 1,688	\$ 1,577

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Unamortized debt discount and premium, net (Accounts 225 and 226)	1	1
Long-term debt	\$ 1,689	\$ 1,578

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

Long-term debt maturities at DPL in the periods 2021 through 2025 and thereafter are as follows:

Year	DPL
2021	\$ 82
2022	3
2023	503
2024	3
2025	3
Thereafter	1,094
Total	<u>\$ 1,688</u>

Debt Covenants

As of December 31, 2020, 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, 2020 and 2019. DPL has no financial liabilities classified as Level 1.

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, 2020	December 31, 2019
Carrying	Carrying

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

	Amount			Fair Value			Amount			Fair Value						
		Level 2	Level 3	Total		Level 2	Level 3	Total		Level 2	Level 3	Total				
Long-term debt (Account 221, 224-227, 243)	\$	1,689	\$	1,484	\$	455	\$	1,939	\$	1,579	\$	1,408	\$	311	\$	1,719

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

As of December 31, 2020 and 2019, the balance for cash equivalents, Rabbi trust investments, and deferred compensation obligations was immaterial.

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

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 for DPL that have been recorded since the acquisition date and the remaining obligations as of December 31, 2020:

<u>Description</u>	<u>December 31, 2020</u>
Total commitments	\$ 89
Remaining commitments ^(a)	\$ 7

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

DPL has committed to conducting three request for proposals (RFP) to procure up to a total of 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards. DPL has conducted two of the three 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 DPSC in March 2019. The third and final 40 MW wind REC tranche will be conducted in 2022.

Commercial Commitments

DPL's commercial commitments as of December 31, 2020, representing commitments potentially triggered by future events, were as follows:

	<u>Expiration within</u>						<u>2026 and beyond</u>
	<u>Total</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	
Surety bonds ^(a)	\$ 4	\$ 4	\$ —	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	12	1	1	1	3	2	4
Total commercial commitments	<u>\$ 16</u>	<u>\$ 5</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 3</u>	<u>\$ 2</u>	<u>\$ 4</u>

(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

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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 \$30 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, 2020 were as follows:

2021	\$ 11
2022	10
2023	9
2024	8
2025	7
Remaining years	<u>35</u>
Total minimum future lease payments	<u>\$ 80</u>

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 almost all 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.

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

As of both December 31, 2020 and 2019, DPL has 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 in Delaware and Maryland. DPL is prohibited from paying a dividend on its common shares if (a) after the dividend payment, DPL's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the DPSC and MDPSC or (b) DPL's senior unsecured credit rating is rated by one of the three major credit rating agencies below 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. 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

The following table presents common stock authorized and outstanding as of December 31, 2020 and 2019:

	Par Value	Shares Authorized	December 31,	
			2020	2019
			Shares Outstanding	
DPL	\$ 2.25	1,000	1,000	1,000

14. Supplemental Financial Information

Supplemental Statement of Income Information

The following table provides additional information about DPL's Statements of Income for the years ended December 31, 2020 and 2019:

	For the Year Ended December 31,	
	2020	2019
Taxes other than income (Accounts 408.1 and 408.2)		
Utility(a)	\$ 21	\$ 18

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

Property	39	34
Payroll	5	4

- (a) DPL's 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 DPL's Statements of Income.

Supplemental Statement of Cash Flows Information

Cash paid for interest (net of amount capitalized) was \$61 million and \$59 million for the years ended December 31, 2020 and 2019. Cash paid for income taxes (net of refunds) was \$12 million and \$19 million for the years ended December 31, 2020 and 2019, respectively.

DPL's Statement of Cash Flows included non-cash investing activities relating to capital expenditures not paid increased (decreased) by \$20 million and \$(4) million for the years ended December 31, 2020 and 2019, respectively.

15. Related Party Transactions

Expenses from Exelon Generation LLC

Generation, a related party of DPL, provides a portion of DPL's energy requirements under its MDPSC and DPSC approved market based SOS commodity programs. DPL's expense from Generation of \$75 million and \$70 million for the years ended December 31, 2020 and 2019, respectively, was primarily recorded as Purchased power, and an immaterial amount recorded as Operating and maintenance expense

Operating and maintenance expense from Business Services Corporation

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

	<u>Operating and maintenance from affiliates</u>		<u>Capitalized costs</u>	
	<u>For the years ended December 31,</u>		<u>For the years ended December 31,</u>	
	<u>2020</u>	<u>2019</u>	<u>2020</u>	<u>2019</u>
BSC	\$ 54	\$ 52	\$ 51	\$ 25
PHISCO	97	100	18	20

Current Receivables from Affiliates (Account 146)

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

	<u>As of December 31,</u>	
	<u>2020</u>	<u>2019</u>
Other	\$ 1	\$ —
Total	\$ 1	\$ —

Current Payables to Affiliates (Account 234)

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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

	As of December 31,	
	2020	2019
Generation	\$ 3	\$ 7
ComEd	1	—
ACE	—	3
BSC	21	10
PHISCO	10	11
Other	1	1
Total	<u>\$ 36</u>	<u>\$ 32</u>

Borrowings from PHI intercompany money pool

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

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
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

(Mo, Da, Yr)

03/29/2021

Year/Period of Report

End of 2020/Q4

Document Accession #: 20210329-8026

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1					
2					
3					
4				147,396,994	147,396,994
5					
6					
7					
8					
9				123,360,954	123,360,954
10					

**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)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	5,289,866,312	4,484,488,722
4	Property Under Capital Leases	25,369,863	25,369,863
5	Plant Purchased or Sold		
6	Completed Construction not Classified	348,656,572	222,609,081
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,663,892,747	4,732,467,666
9	Leased to Others		
10	Held for Future Use	7,861,982	7,861,982
11	Construction Work in Progress	163,907,674	134,660,070
12	Acquisition Adjustments	50,046,281	50,046,281
13	Total Utility Plant (8 thru 12)	5,885,708,684	4,925,035,999
14	Accum Prov for Depr, Amort, & Depl	1,574,752,836	1,222,071,518
15	Net Utility Plant (13 less 14)	4,310,955,848	3,702,964,481
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,472,836,526	1,153,616,498
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	54,650,913	21,189,623
22	Total In Service (18 thru 21)	1,527,487,439	1,174,806,121
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	Amort of Plant Acquisition Adj	47,265,397	47,265,397
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,574,752,836	1,222,071,518

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
644,088,887				161,288,703	3
					4
					5
107,298,969				18,748,522	6
					7
751,387,856				180,037,225	8
					9
					10
18,833,438				10,414,166	11
					12
770,221,294				190,451,391	13
246,718,837				105,962,481	14
523,502,457				84,488,910	15
					16
					17
245,287,058				73,932,970	18
					19
					20
1,431,779				32,029,511	21
246,718,837				105,962,481	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
246,718,837				105,962,481	33

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year
			Additions (c)
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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 03/29/2021	Year/Period of Report End of 2020/Q4
Document Accession #: 20210329-8026 Submission Date: 03/29/2021					
NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)					
Changes during Year				Balance End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)				
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22

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 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	2,341	
4	(303) Miscellaneous Intangible Plant	17,298,633	14,497,987
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	17,300,974	14,497,987
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		
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)		

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	54,074,716	2,477
49	(352) Structures and Improvements	55,825,995	18,179,781
50	(353) Station Equipment	630,456,812	9,269,013
51	(354) Towers and Fixtures	73,958,461	7
52	(355) Poles and Fixtures	532,223,526	47,402,062
53	(356) Overhead Conductors and Devices	315,165,340	3,842,598
54	(357) Underground Conduit	45,526,298	-2,925
55	(358) Underground Conductors and Devices	23,195,237	
56	(359) Roads and Trails	731,224	535,417
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,731,157,609	79,228,430
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	15,389,713	
61	(361) Structures and Improvements	41,949,648	7,950,657
62	(362) Station Equipment	423,183,984	16,675,696
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	219,830,399	19,438,896
65	(365) Overhead Conductors and Devices	364,214,462	30,648,825
66	(366) Underground Conduit	23,718,796	1,091,681
67	(367) Underground Conductors and Devices	386,542,635	22,033,562
68	(368) Line Transformers	558,554,912	33,323,957
69	(369) Services	208,480,674	4,395,871
70	(370) Meters	131,126,656	3,107,018
71	(371) Installations on Customer Premises	42,210,373	-584,249
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	68,286,264	5,359,880
74	(374) Asset Retirement Costs for Distribution Plant	5,903,710	1,885
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,489,392,226	143,443,679
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	2,684,231	
87	(390) Structures and Improvements	31,409,185	1,076,164
88	(391) Office Furniture and Equipment	8,730,414	1,833,992
89	(392) Transportation Equipment	11,337,091	15,205,448
90	(393) Stores Equipment	504,667	
91	(394) Tools, Shop and Garage Equipment	14,582,997	3,554,418
92	(395) Laboratory Equipment		
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	154,518,868	36,656,701
95	(398) Miscellaneous Equipment	2,974,724	49,000
96	SUBTOTAL (Enter Total of lines 86 thru 95)	226,742,177	58,375,723
97	(399) Other Tangible Property	4,735	
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	226,746,912	58,375,723
100	TOTAL (Accounts 101 and 106)	4,464,597,721	295,545,819
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)	4,464,597,721	295,545,819

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			2,341		3
			31,796,620		4
			31,798,961		5
					6
					7
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
21			54,077,172	48
179,218			73,826,558	49
4,027,302			635,698,523	50
			73,958,468	51
1,135,199			578,490,389	52
1,135,200			317,872,738	53
		-39,447,027	6,076,346	54
		39,447,027	62,642,264	55
			1,266,641	56
				57
6,476,940			1,803,909,099	58
				59
			15,389,713	60
70,876			49,829,429	61
1,516,756			438,342,924	62
				63
372,172			238,897,123	64
2,867,115			391,996,172	65
7,356			24,803,121	66
6,616,762			401,959,435	67
3,608,608			588,270,261	68
75,085			212,801,460	69
1,603,485		33,591	132,663,780	70
34,342			41,591,782	71
				72
1,621,175			72,024,969	73
86,353			5,819,242	74
18,480,085		33,591	2,614,389,411	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			2,684,231	86
3,227			32,482,122	87
42,543			10,521,863	88
81,353			26,461,186	89
40,756			463,911	90
302,118			17,835,297	91
				92
				93
2,266,088			188,909,481	94
16,355			3,007,369	95
2,752,440			282,365,460	96
			4,735	97
				98
2,752,440			282,370,195	99
27,709,465		33,591	4,732,467,666	100
				101
				102
				103
27,709,465		33,591	4,732,467,666	104

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
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6					
7					
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43					
44					
45					
46					
47	TOTAL				

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	12/1/2019	12/31/2021	3,178,224
3	Queenstown Substation: SSTA979	12/1/2019	5/31/2022	1,592,742
4	Ocean City-West Culver : SS322B	11/1/2019	2/28/2024	516,156
5	Lakeside Substation Land; 8 Acres, Talbot County MD	12/1/2010	6/1/2030	406,468
6	Magnolia Substation Land: 11+Acres	8/1/2010	6/1/2030	1,180,361
7	Ocean City-St Louis & 2nd : SSTA749	12/1/2020	2/28/2024	761,349
8				
9				
10	Total of Land under \$250,000			226,682
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
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31				
32				
33				
34				
35				
36				
37				
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41				
42				
43				
44				
45				
46				
47	Total			7,861,982

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	63869: DPL MD: Marvel Road CAP	6,983,098
2	IDS Design Build Install DE	4,199,475
3	DPL MD CAP: Narrows Sub	4,083,326
4	DPL MD CAP: Queenstown Sub	3,993,123
5	DPL MD CAP: Stevensville	3,098,724
6	DPL MD CAP Chestertown Plan	2,896,121
7	Tower Replacement DE	2,783,143
8	DPL LMR Infrastructure DE Hardware	2,748,501
9	EU ADMS Implementation Software	2,653,302
10	Indian River Spare Transformer	2,629,526
11	BIDA-AMI Ph2 Software	2,447,961
12	DPL MD CAP: CHESTERTOWN: DISTR	2,417,938
13	Crisfield Sub New 69KV Term	2,416,573
14	Carville Switchgear	2,339,186
15	6719 E Market To Cambridge Rebuild	2,329,385
16	Crisfield Kings Creek	2,200,605
17	Colora Fence & Security System	2,179,199
18	DPL LMR Infrastructure MD Hardware	1,948,218
19	DPL MD CAP: Chestertown: Ches	1,783,447
20	Router Upgrade Cores Edges DE	1,711,043
21	Zoar Sub (DEC) - New 69 kV Rin	1,603,182
22	Misc Trans Repairs Bay DE	1,598,899
23	MD3476 Feeder Extension	1,478,121
24	EU GIS CORE Software	1,474,985
25	East New Market T2 Install	1,448,800
26	DPL MD CAP: Chestertown Plan	1,403,651
27	N.Salisbury Spare Transformer	1,340,989
28	DPL MD CAP Chester Sub Bus Up	1,320,005
29	Maryland Sub Spare Transformer	1,297,623
30	North East Ops Renovation Cap	1,249,751
31	64405: DPL: Kennett Sq TSO Ren	1,233,358
32	DE0532 Cable Replacement	1,227,537
33	Centreville Ops Renovation Cap	1,207,779
34	Utility Project Port Management Tool Software	1,161,425
35	Crisfield T1 Replace Transformer ECA	1,127,729
36	MD2276 Feeder Improvements	1,103,525
37	Cable DE	1,075,595
38	67891 NCRO Switchgear Replace	1,067,708
39	IDS Design Build Install DPL MD	1,014,282
40	UI Planner Software	1,014,128
41	Miscellaneous projects under \$1,000,000	51,369,104
42		
43	TOTAL	134,660,070

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 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), 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.

Section A. Balances and Changes During Year

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)
1	Balance Beginning of Year	1,081,252,275	1,081,252,275		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	129,073,984	129,073,984		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,065,687	2,065,687		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	194,498	194,498		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	131,334,169	131,334,169		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	27,709,465	27,709,465		
13	Cost of Removal	33,040,618	33,040,618		
14	Salvage (Credit)	521,943	521,943		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	60,228,140	60,228,140		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	Third Party Reimbursements	1,258,194	1,258,194		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,153,616,498	1,153,616,498		

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	421,664,575	421,664,575		
26	Distribution	660,469,030	660,469,030		
27	Regional Transmission and Market Operation				
28	General	71,482,893	71,482,893		
29	TOTAL (Enter Total of lines 20 thru 28)	1,153,616,498	1,153,616,498		

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 219 Line No.: 8 Column: b

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

ARO	\$ 194,498
Total	\$ 194,498

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
 - (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
 - (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
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28				
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31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	0	TOTAL	

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
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				42

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	39,724,396	45,440,265	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)	442,943	723,062	Electric
9	Distribution Plant (Estimated)	4,475,602	4,830,407	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)	44,642,941	50,993,734	
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 (Per Balance Sheet)	44,642,941	50,993,734	

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 5 Column: b

Assigned to - Construction (Estimated)	
Transmission Plant - Electric (Estimated)	\$ 3,577,411
Distribution Plant - Electric & Gas (Estimated)	36,146,985
Assigned to - Construction (Estimated)	<u>\$ 39,724,396</u>

Schedule Page: 227 Line No.: 5 Column: c

Assigned to - Construction (Estimated)	
Transmission Plant - Electric (Estimated)	\$ 5,916,322
Distribution Plant - Electric & Gas (Estimated)	39,523,943
Assigned to - Construction (Estimated)	<u>\$ 45,440,265</u>

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2021	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	326,940.00	8,787,093		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	DE RPS RECs Purchased	859,514.00	20,174,969		
10					
11	MD HPS RECs Purchased	27,717.00	644,064		
12	MD RECs Received	449,785.00	6,606,375		
13					
14					
15	Total	1,337,016.00	27,425,408		
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20	Total				
21	Cost of Sales/Transfers:				
22	DE RECs Retired	849,642.00	19,854,159		
23	MD RECs Retired	449,785.00	6,606,375		
24					
25					
26					
27					
28	Total	1,299,427.00	26,460,534		
29	Balance-End of Year	364,529.00	9,751,967		
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

- 6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
- 7. Report on Lines 8-14 the names of vendors/transferrers of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
- 8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
- 9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
- 10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2022		2023		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						326,940.00	8,787,093	1
								2
								3
								4
								5
								6
								7
								8
						859,514.00	20,174,969	9
								10
						27,717.00	644,064	11
						449,785.00	6,606,375	12
								13
								14
						1,337,016.00	27,425,408	15
								16
								17
								18
								19
								20
								21
						849,642.00	19,854,159	22
						449,785.00	6,606,375	23
								24
								25
								26
								27
						1,299,427.00	26,460,534	28
						364,529.00	9,751,967	29
								30
								31
								32
								33
								34
								35
								36
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								40
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								43
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								45
								46

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 15 Column: b

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

Schedule Page: 228 Line No.: 15 Column: c

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

Schedule Page: 228 Line No.: 28 Column: b

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

Schedule Page: 228 Line No.: 28 Column: c

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

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2021	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

- 6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
- 7. Report on Lines 8-14 the names of vendors/transferrers of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
- 8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
- 9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
- 10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2022		2023		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
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								46

Name of Respondent

Delmarva Power & Light Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

Year/Period of Report

End of 2020/Q4

Document Accession #: 20210329-80026

Submission Date: 03/29/2021

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 Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent

Delmarva Power & Light Company

This Report Is:

(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)

03/29/2021

Year/Period of Report

End of 2020/Q4

Document Accession #: 20210329-80026

Submission Date: 03/29/2021

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 Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

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				
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	N/A				
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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 the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Deferred Fuel Costs	2,048,856	7,067,130	Various	9,115,986	
2	Other Vacation Accrual	7,203,495	3,122,793	Various	7,203,497	3,122,791
3	Asset Retirement Obligation	1,384,841	452,927	426.5	52,587	1,785,181
4	Transmission Service Revenue	2,152,790	13,107,165	Various	13,590,252	1,669,703
5	DE Integrated Resource Planning (IRP)	104,635		407.3	104,635	
6	DE Bluewater Wind Request for Proposal Costs	127,034		407.3	127,034	
7	DE Renewable Energy Portfolio Standards		33,834,147	Various	28,170,199	5,663,948
8	DE Electric Costs to Achieve (CTA) Deferral	4,012,589		407.3	1,473,484	2,539,105
9	FAS 133 DE Gas Derivatives	1,417,933	1,095,541	242	1,417,934	1,095,540
10	DE Third Party Supplier Recovery	244,381	1,513,122	Various	715,472	1,042,031
11	MD Bill Stabilization Adjustment Deferral		53,874,234	Various	53,874,234	
12	MD Third Party Supplier Recovery	1,597,391	1,271,944	Various	832,077	2,037,258
13	MD Costs to Achieve (CTA) Deferral	2,845,307		407.3	1,090,910	1,754,397
14	Billing System-MD Recovery	683,496		903	321,644	361,852
15	MD Rate Case Costs	30,178	132,117	928	48,348	113,947
16	DE DSM - Energy Efficiency	315,375	1,900,945	Various	1,218,218	998,102
17	AMI / Smart Grid - DE	32,866,372	103,766	Various	4,010,597	28,959,541
18	Recoverable DE DLC Costs	15,653,056		407.3	2,102,472	13,550,584
19	DE Gas IMU	6,674,667	21,208	Various	706,772	5,989,103
20	DE Gas Costs to Achieve (CTA) Deferral	1,281,261		407.3	413,392	867,869
21	DE Gas IMU Battery Project Costs	1,726,357		893	1,726,357	
22	DSM - Energy Efficiency Products MD	50,444,477	28,768,727	407.3	18,136,901	61,076,303
23	DSM - Direct Load Control Program MD	7,802,673	1,021,491	407.3	1,850,234	6,973,930
24	AMI / Smart Grid - MD	12,043,734	72,792	407.3	1,773,172	10,343,354
25	MD AMI Loss on Retirement of Meters	10,414,761		407.3	1,388,331	9,026,430
26	Delaware SOS:					
27	DE SOS - Energy		5,111,469	254	4,883,665	227,804
28	DE SOS - Transmission	4,514,874	5,509,424	Various	10,024,298	
29	DE SOS - Administrative Costs		3,941,453	254	3,690,963	250,490
30	Maryland SOS:					
31	MD SOS - Energy		4,210,065	Various	2,594,272	1,615,793
32	MD SOS - Transmission	2,955,764	3,072,962	407.3	3,086,700	2,942,026
33	MD SOS - Administrative Costs	333,717	331,393	407.3	620,294	44,816
34	MD Incremental Storm Costs	3,377,601	1,790,260	Various	939,841	4,228,020
35	Tax Cuts and Jobs Act	1,761,387		923	175,544	1,585,843
36	MD RM54 Recovery	161,580	53,204	903	40,719	174,065
37	DE Electric Distribution System Improvement Charge		140,857	407.3	94,654	46,203
38	DE Gas Distribution System Improvement Charge		253,227	407.3	168,446	84,781
39	MD Electric Vehicle	141,896	273,432	923	41	415,287
40	SOS Deferral for FERC 715 Settlement		409,878	407.3	132,025	277,853
41	DE Incremental COVID-19 Cost		10,094,566	Various	6,951,755	3,142,811
42	MD Incremental COVID-19 Cost		8,011,789	Various	4,341,533	3,670,256
43	DE Electric Vehicle		8,000			8,000
44	TOTAL	176,322,478	190,572,028		189,209,489	177,685,017

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 1 Column: a

This note applies to Schedule Page: 232 Line No.: 1 through 43, Column: a: DPL records its regulatory assets in account 182.3 based on the following rate orders or legislation:

Line No.	Description of Other Regulatory Assets	Rate Order Docket Number or Recovery Mechanism
1	Deferred Fuel Costs	DEPSC Docket No. 19-0556
4	Transmission Service Revenue	FERC Docket No. ER05-515
5	DE Integrated Resource Planning (IRP)	DEPSC Docket No. 09-414, DEPSC Docket No. 09-276T
6	DE Bluewater Wind Request for Proposal Costs	DEPSC Docket No. 09-414, DEPSC Docket No. 09-276T
7	DE Renewable Energy Portfolio Standards	DEPSC Regulation Docket No. 56
8	DE Electric Costs to Achieve (CTA) Deferral	DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977
9	FAS 133 DE Gas Derivatives	DEPSC Docket No. 97-293F
10	DE Third Party Supplier Recovery	DEPSC Docket No. 15-1693
11	MD Bill Stabilization Adjustment Deferral	MDPSC Case No. 9092, MDPSC Case No. 9093
12	MD Third Party Supplier Recovery	MDPSC Maillog 116829
13	MD Costs to Achieve (CTA) Deferral	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630
14	Billing System-MD Recovery	MDPSC Case No. 9424
15	MD Rate Case Costs	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630
16	DE DSM - Energy Efficiency	DEPSC Docket No. 17-0985
17	AMI / Smart Grid - DE	DEPSC Docket No. 11-528, DEPSC Docket No. 13-115, DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977,
18	Recoverable DE DLC Costs	DEPSC Docket No. 16-0649, DEPSC Docket No. 17-0977
19	DE Gas IMU	DEPSC Docket No. 09-277T, DEPSC Docket No. 10-237, DEPSC Docket No. 11-528, DEPSC Docket No. 12-546, DEPSC Docket No. 17-0978
20	DE Gas Costs to Achieve (CTA) Deferral	DEPSC Docket No. 17-0978, DEPSC Docket No. 20-0150
21	DE Gas IMU Battery Project Costs	DEPSC Docket No. 17-0978
22	DSM - Energy Efficiency Products MD	MDPSC Case No. 9156
23	DSM - Direct Load Control Program MD	MDPSC Case No. 9156
24	AMI / Smart Grid - MD	MDPSC Case No. 9424, MDPSC Case No. 9455
25	MD AMI Loss on Retirement of Meters	MDPSC Case No. 9424
27	DE SOS - Energy	DEPSC Docket No. 04-391
28	DE SOS - Transmission	DEPSC Docket No. 04-391
29	DE SOS - Administrative Costs	DEPSC Docket No. 04-391

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FOOTNOTE DATA			

31	MD SOS - Energy	MDPSC Case No. 8908
32	MD SOS - Transmission	MDPSC Case No. 8908
33	MD SOS - Administrative Costs	MDPSC Case No. 8908
34	MD Incremental Storm Costs	MDPSC Case No. 9424, MDPSC Case No. 9455, MDPSC Case No. 9630
35	Tax Cuts and Jobs Act	MDPSC Case No. 9630
36	MD RM54 Recovery	MDPSC Case No. 9630
37	DE Electric Distribution System Improvement Charge	DEPSC Regulation Docket No. 64
38	DE Gas Distribution System Improvement Charge	DEPSC Regulation Docket No. 64
39	MD Electric Vehicle	MDPSC Case No. 9478
40	SOS Deferral for FERC 715 Settlement	FERC Docket No. ER15-1387-006, FERC Docket No. ER15-1344-007, FERC Docket No. ER18-680-000
41	DE Incremental COVID-19 Cost	DEPSC Docket No. 20-0286
42	MD Incremental COVID-19 Cost	MDPSC Order No. 89636
43	DE Electric Vehicle	DEPSC Docket No. 17-1094

Schedule Page: 232 Line No.: 1 Column: d

The following are the individual components of "Various":

\$	5,480,678	recorded to account 254 - Reclass consistent with regulatory recovery position, included in DE Deferred Fuel Costs-Gas line 13, pg. 278
	89,669	recorded to account 431
	<u>3,545,639</u>	recorded to account 805.1
\$	9,115,986	Total

Schedule Page: 232 Line No.: 1 Column: e

This note applies to Schedule Page: 232 Line No.: 1 through 43, Column: e: DPL amortizes its regulatory assets in account 182.3 based on the following amortization periods:

Line No.	Description of Other Regulatory Assets	Amortization Lives
5	DE Integrated Resource Planning (IRP)	10 years
6	DE Bluewater Wind Request for Proposal Costs	10 years
8	DE Electric Costs to Achieve (CTA) Deferral	5 years
13	MD Costs to Achieve (CTA) Deferral	5 years
14	Billing System-MD Recovery	5 years
15	MD Rate Case Costs	3 years
17	AMI / Smart Grid - DE	15 years
18	Recoverable DE DLC Costs	10 years
19	DE Gas IMU	15 years

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

20	DE Gas Costs to Achieve (CTA) Deferral	5 years
22	DSM - Energy Efficiency Products MD	5 years
23	DSM - Direct Load Control Program MD	15 years
24	AMI / Smart Grid - MD	10 years
25	MD AMI Loss on Retirement of Meters	10 years
34	MD Incremental Storm Costs	5 years
35	Tax Cuts and Jobs Act	32 years
36	MD RM54 Recovery	3 years

Schedule Page: 232 Line No.: 2 Column: d

The following are the individual components of "Various":

\$	357,079	recorded to account 236 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability.
	5,641,065	recorded to account 242 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability.
	1,205,353	recorded to account 923
<hr/>		
\$	7,203,497	Total

Schedule Page: 232 Line No.: 4 Column: d

The following are the individual components of "Various":

\$	6,857,275	recorded to account 254 - recovery of Tax Cuts and Jobs Act regulatory liability, included in Tax Cuts and Jobs Act as well as Transmission Service Revenue lines 18 and 27, respectively, pg. 278
	6,732,977	recorded to account 456.1
<hr/>		
\$	13,590,252	Total

Schedule Page: 232 Line No.: 7 Column: d

The following are the individual components of "Various":

\$	23,126,726	recorded to account 254 - Reclass consistent with regulatory recovery position, included in DE Renewable Portfolio Surcharge Deferral line 12, pg. 278
	5,007,993	recorded to account 407.3
	35,480	recorded to account 431
<hr/>		
\$	28,170,199	Total

Schedule Page: 232 Line No.: 9 Column: d

The following is the individual component of "242":

\$	1,417,934	recorded to account 242 - Derivative unrealized loss recorded to B/S per ASC 815
----	-----------	--

Schedule Page: 232 Line No.: 10 Column: d

The following are the individual components of "Various":

\$	338,184	recorded to account 144 - Relief of Regulatory Asset through Accounts Receivable Reserve adjustments
	377,288	recorded to account 232 - Relief of Regulatory Asset through Third Party Supplier Discount
<hr/>		
\$	715,472	Total

Schedule Page: 232 Line No.: 11 Column: d

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

The following are the individual components of "Various":

\$	43,266,111	recorded to account 254 - Reclass consistent with regulatory recovery position, included in MD Bill Stabilization Adjustment Deferral line 22, pg. 278
	10,608,123	recorded to account 456
\$	53,874,234	Total

Schedule Page: 232 Line No.: 12 Column: d

The following are the individual components of "Various":

\$	108,599	recorded to account 142 - Relief of Regulatory Asset through Accounts Receivable adjustments
	156,347	recorded to account 144 - Relief of Regulatory Asset through Accounts Receivable Reserve adjustments
	567,131	recorded to account 232 - Relief of Regulatory Asset through Third Party Supplier Discount
\$	832,077	Total

Schedule Page: 232 Line No.: 16 Column: d

The following are the individual components of "Various":

\$	354,146	recorded to account 407.3
	864,072	recorded to account 908
\$	1,218,218	Total

Schedule Page: 232 Line No.: 17 Column: d

The following are the individual components of "Various":

\$	3,940,785	recorded to account 407.3
	69,812	recorded to account 923
\$	4,010,597	Total

Schedule Page: 232 Line No.: 19 Column: d

The following are the individual components of "Various":

\$	636,272	recorded to account 407.3
	70,500	recorded to account 923
\$	706,772	Total

Schedule Page: 232 Line No.: 27 Column: d

The following is the individual component of "254":

\$	4,883,665	recorded to account 254 - Reclass consistent with regulatory recovery position, included in DE SOS: Energy line 7, pg. 278
----	-----------	--

Schedule Page: 232 Line No.: 28 Column: d

The following are the individual components of "Various":

\$	3,746,315	recorded to account 254 - Reclass consistent with regulatory recovery position, included in DE SOS: Transmission line 8, pg. 278
	6,277,983	recorded to account 407.3
\$	10,024,298	Total

Schedule Page: 232 Line No.: 29 Column: d

The following is the individual component of "254":

\$	3,690,963	recorded to account 254 - Reclass consistent with regulatory recovery position, included in DE SOS: Administrative Costs line 9, pg. 278
----	-----------	--

Schedule Page: 232 Line No.: 31 Column: d

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

The following are the individual components of "Various":

\$	467,318	recorded to account 254 - Reclass consistent with regulatory recovery position, included in MD SOS: Energy line 5, pg. 278
	<u>2,126,954</u>	recorded to account 407.3
\$	2,594,272	Total

Schedule Page: 232 Line No.: 34 Column: d

The following are the individual components of "Various":

\$	14,873	recorded to account 407.3
	11,436	recorded to account 408.1
	61,704	recorded to account 588
	799,249	recorded to account 593
	48,711	recorded to account 903
	<u>3,868</u>	recorded to account 908
\$	939,841	Total

Schedule Page: 232 Line No.: 41 Column: d

The following are the individual components of "Various":

\$	3,418,411	recorded to account 254 - Reclass consistent with regulatory recovery position, included in DE Incremental COVID-19 Cost line 28, pg. 278
	<u>3,533,344</u>	recorded to account 407.4
\$	6,951,755	Total

Schedule Page: 232 Line No.: 42 Column: d

The following are the individual components of "Various":

\$	2,696,333	recorded to account 254 - Reclass consistent with regulatory recovery position, included in MD Incremental COVID-19 Cost line 29, pg. 278
	<u>1,645,200</u>	recorded to account 407.4
\$	4,341,533	Total

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Prepaid Pension Costs	170,844,366	735,620	various	10,006,441	161,573,545
2	LT Customer Payment Receivables	91,402		143	8,606	82,796
3	LT Receivable from PJM	2,117,676		143	423,535	1,694,141
4	Other A/R Worker Compensation	752,348	226,367	various	33,956	944,759
5	Materials & Equipment		4,036,990			4,036,990
6	Other	19,953	51,559	various	15,260	56,252
7						
8						
9						
10						
11						
12						
13						
14						
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	173,825,745				168,388,483

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 233 Line No.: 1 Column: d

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

Schedule Page: 233 Line No.: 4 Column: d

Other A/R Worker Compensation is offset in Accounts 925, 107 and 108.

Schedule Page: 233 Line No.: 6 Column: d

Other is various accounts for minor amounts.

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 of Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Electric	176,884,513	177,162,243
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	176,884,513	177,162,243
9	Gas		
10	Gas	21,209,409	21,322,988
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	21,209,409	21,322,988
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	198,093,922	198,485,231

Notes

Account 190 Fed Inc. Activity:

410 Debits 5,992,230

411 Credits 25,425,802

Net Debits (19,433,572)

Account 190 State Inc. Activity:

410 Debits 347,770

411 Credits 1,354,226

Net Debits (1,006,456)

Account 190 Activity B/S Only:

410 Debits -

411 Credits 20,048,719

Net Debits 20,048,719

Net Change 391,309

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Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 234 Line No.: 18 Column: b

The following lines from 2019 FERC Form 1, column (c) are individual components of 2019 beginning balance in column (b):

Electric	56,701,567	Line 2
Electric FAS109	120,182,946	Line 3
	176,884,513	
Gas	8,499,429	Line 10
Gas FAS109	12,709,980	Line 11
Total	21,209,409	

190	Electric	Gas	Total
Accrued Benefits	1,024,666	166,806	1,191,472
Accrued Bonuses & Incentives	1,589,937	258,827	1,848,764
Accrued Environmental Liability	226,244	36,830	263,074
Accrued OPEB	4,570,232	743,991	5,314,223
Accrued Other Expenses	1,868,185	304,123	2,172,308
Accrued Payroll Taxes - Annual Incentive Plan (AIP)	87,455	14,237	101,692
Accrued Vacation	1,134,128	184,625	1,318,753
Accrued Worker's Compensation	1,038,320	169,029	1,207,349
Allowance for Doubtful Accounts	3,486,262	567,531	4,053,793
Asset Retirement Obligation	3,363,470	547,542	3,911,012
Deferred Compensation	7,417	1,207	8,624
Merger Commitments	346,377	56,387	402,764
Purchased Power	2,994,725	487,513	3,482,238
Regulatory Liability	(3,501,870)	(579,919)	(4,081,789)
Sales & Use Tax Reserve	249,788	40,663	290,451
State Net Operating Loss Carryforward	39,734,139	4,414,904	44,149,043
Unamortized Investment Tax Credit	477,683	77,762	555,445
Other 190	(42,777)	(6,963)	(49,740)
FAS 109 - Regulatory Liability	118,230,133	13,724,313	131,954,446
Total	178,884,514	21,209,408	198,093,922

Schedule Page: 234 Line No.: 18 Column: c

190	Electric	Gas	Total
Accrued Benefits	1,117,049	181,845	1,298,894
Accrued Bonuses & Incentives	2,036,735	331,562	2,368,297
Accrued Environmental Liability	215,396	35,065	250,461
Accrued Legal	14,897	2,425	17,322
Accrued OPEB	4,270,141	695,139	4,965,280
Accrued Other Expenses	2,714,605	441,912	3,156,517
Accrued Payroll Taxes - Annual Incentive Plan (AIP)	142,830	23,251	166,081
Accrued Severance	21,582	3,513	25,095
Accrued Vacation	377,719	61,489	439,208
Accrued Worker's Compensation	1,218,601	198,377	1,416,978
Allowance for Doubtful Accounts	7,200,636	1,172,196	8,372,832
Asset Retirement Obligation	3,759,475	612,008	4,371,483
Deferred Compensation	18,734	3,050	21,784

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

Deferred Revenue	2,792,946	454,666	3,247,612
Other Deferred Credits	291,868	47,514	339,382
Purchased Power	3,188,899	519,123	3,708,022
Regulatory Liability	2,250,961	337,650	2,588,611
Sales & Use Tax Reserve	254,873	41,491	296,364
State Income Taxes	(44,821)	(7,297)	(52,118)
State Net Operating Loss Carryforward	44,189,092	4,909,899	49,098,991
Unamortized Investment Tax Credit	403,234	65,643	468,877
Other 190	11,637	1,894	13,531
FAS 109 - Regulatory Liability	100,715,154	11,190,573	111,905,727
Total	177,162,243	21,322,988	198,485,231

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock (Account 201)	1,000	2.25	
2	Total Common Stock	1,000		
3				
4	Preferred Stock Issued (Account 204)			
5	None			
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Document Accession #: 20210329-80026

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
 4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
 5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
- Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1,000	2,250					1
1,000	2,250					2
						3
						4
						5
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Document Accession #: 20210329-8006 Submission Date: 03/29/2021

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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 total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

- (a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
- (b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- (c) Gain on 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.
- (d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	ACCOUNT 210	
2		
3	Preferred Adjustable Rate	1,947,893
4	Common Stock - \$2.25 Par Value	318
5	Loss on Redemption of Preferred Stock	-609,815
6	Subtotal	1,338,396
7		
8		
9	ACCOUNT 211	
10		
11	General Corporate	-294,423,184
12	Allocation of non-acquisition debt from Holding Co. to Subsidiary	6,348,503
13	Capital Contribution from Parent	847,918,334
14	Subtotal	559,843,653
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37		
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40	TOTAL	561,182,049

Document Accession #: 20210329-80026 Submission Date: 03/29/2021

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	9,924,450
2		
3		
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21		
22	TOTAL	9,924,450

Document Accession #: 20210329-8026 Submission Date: 03/29/2021

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Bonds (Account 221)		
2	Variable Rate Demand Exempt Facilities Bonds - 1993	15,500,000	275,796
3	Variable Rate Demand Exempt Facilities Bonds - 1994	30,000,000	440,787
4	Variable Rate Demand Exempt Facilities Bonds - 1999	22,330,000	334,028
5	Variable Rate Demand Exempt Facilities Bonds - 1999	11,000,000	
6	4% FMB due 6/1/2042	250,000,000	2,187,500
7			512,500 D
8	4.15% FMB due 5/15/2045	200,000,000	2,313,720
9			172,000 D
10	5.40% Medium Term Notes	78,400,000	1,406,618
11	3.50% FMB due 11/15/2023	300,000,000	2,572,640
12			126,000 D
13	3.50% FMB due 11/15/2023	200,000,000	1,861,600
14			4,264,000 D
15	4.15% FMB due 5/15/2045	175,000,000	1,531,250
16			-775,250 P
17	4.27% FMB due 6/15/2048	200,000,000	1,774,124
18	4.14% FMB due 12/12/2049	75,000,000	716,972
19	2.53% FMB due 6/9/2030	100,000,000	756,388
20	Tax Exempt Bonds	78,400,000	851,895
21	SUBTOTAL - Account 221	1,735,630,000	21,322,568
22			
23			
24	Account 224 - Other LTD		
25	Medium Term Notes 7.72% Series C	10,000,000	
26			
27	SUBTOTAL - Account 224	10,000,000	
28			
29			
30			
31			
32			
33	TOTAL	1,745,630,000	21,322,568

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
0	0	0	0			1
10/14/1993	10/01/2028	10/14/1993	10/01/2028	15,500,000	112,930	2
10/10/1994	10/01/2029	10/10/1994	10/01/2029	30,000,000	219,156	3
07/01/1999	07/01/2024	07/01/1999	07/01/2024	22,330,000	160,320	4
07/01/1999	07/01/2024	07/01/1999	07/01/2024	11,000,000	86,698	5
06/26/2012	06/01/2042	06/26/2012	06/01/2042	250,000,000	10,000,000	6
						7
05/11/2015	05/15/2045	05/11/2015	05/15/2045	200,000,000	8,300,000	8
						9
04/01/2010	02/01/2031	04/01/2010	02/01/2031	78,400,000	352,800	10
11/15/2013	11/15/2023	11/15/2013	11/15/2023	300,000,000	10,500,000	11
						12
06/09/2014	11/15/2023	06/09/2014	11/15/2023	200,000,000	7,000,000	13
						14
12/12/2016	05/15/2045	12/12/2016	05/15/2045	175,000,000	7,262,500	15
						16
06/21/2018	06/15/2048	06/21/2018	06/15/2048	200,000,000	8,540,000	17
12/12/2019	12/12/2049	12/12/2019	12/12/2049	75,000,000	3,105,000	18
6/9/2020	6/9/2030	6/9/2020	6/9/2030	100,000,000	1,419,610	19
7/1/2020	7/1/2025	7/1/2020	7/1/2025		2,528,400	20
				1,657,230,000	59,587,414	21
						22
						23
						24
02/07/1997	02/01/2027	02/07/1997	02/01/2027	10,000,000	772,000	25
0	0	0	0			26
0	0	0	0	10,000,000	772,000	27
0		0	0			28
0	0	0	0			29
						30
						31
						32
				1,667,230,000	60,359,414	33

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 19 Column: d

\$100 million of First Mortgage Bonds were issued on June 9, 2020.

Schedule Page: 256 Line No.: 20 Column: d

\$78 million of Tax Exempt Bonds were issued on July 1, 2020.

Schedule Page: 256 Line No.: 32 Column: i

The difference between the total interest reported in column (i) and the balances in accounts 427 and 430 is \$73,849, which represents Service Company related interest from money pool transactions and credit facility commitment fees each of which are reported in account 430.

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)	123,360,954
2		
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	-25,239,136
11		
12		
13		
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	-141,047,012
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-42,925,193
28	Show Computation of Tax:	
29	Federal Income Tax at 21%	-9,014,291
30	Net Operating Loss Utilized	
31	2020 Discrete Adjustments	-3,753,539
32	Income Tax Credits	-260,509
33		
34	Total	-13,028,339
35		
36	Federal Income Tax Acct 409.10	-9,682,605
37	Federal Income Tax Acct 409.20	-3,345,735
38	Total	-13,028,340
39		
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41		
42		
43		
44		

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 261 Line No.: 1 Column: b

Net Income for the Year (Page 117)	123,360,954
Federal Income Taxes	(33,532,194)
State Income Taxes	8,293,059
Pre-tax Book Income	<u>98,121,819</u>
Increase (Decrease) in Taxable Income Resulting From:	
Removal Costs	(38,881,464)
Mixed Service Costs	(32,493,923)
Repair Allowance - Unit of Property	(83,681,081)
Bonus Depreciation	—
Depreciation	14,412,444
CIAC	8,996,312
AFUDC Equity	(4,233,116)
AFUDC Debt	—
Capitalized Interest	1,930,407
Gain/Loss on Disposition of Property	(6,699,359)
Other (Property)	(27,836,677)
Regulatory Assets & Liabilities	(3,074,725)
Pension/OPEB/SERP	4,384,545
Accrued Liabilities	(3,379,276)
Merger Commitment Deferrals	(228,691)
State Income Taxes Deductible	—
Deferred Revenue	11,717,885
Other (Net)	18,019,707
Total Schedule M's	<u>(141,047,012)</u>
Federal Taxable Income	(42,925,193)
Computation of Federal Income Tax:	
Federal Income Tax on Current Year Income (21%)	(9,014,291)
Net Operating Loss Utilized	—
2020 Discrete Adjustments	(3,753,539)
Income Tax Credits	(260,509)
Federal Income Tax	<u>(13,028,339)</u>
Federal Income Tax Account 409.10	(9,682,605)
Federal Income Tax Account 409.20	(3,345,735)
Total	<u>(13,028,340)</u>

Additional information in response to Instruction 2, Page 261:

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

TAXES ACCRUED, PREPAID AND CHARGED 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 (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) 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.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal Income Tax	9,274,438		-13,028,339	11,573,218	15,327,119
2	State Income Tax			23,117	-22,594	-45,711
3	Maryland Use Tax	816,712		-4,329	-367,617	
4	Maryland Property Taxes		7,912,349	18,722,978	3,365,014	2,363,758
5	Maryland Prop. Taxes Other	557,423				-557,423
6	Other Maryland Taxes		119,234	9,109,541	10,007,965	
7	Delaware Property Taxes		9,815,084	19,508,878	20,767,409	876,472
8	Local Delaware Taxes	1,055,898		723,164	751,886	
9	Other Delaware Taxes	1,050,005		10,907,835	9,461,872	
10	Virginia Use Tax	2,804			1,066	
11	Virginia Property Taxes	95,661		193,043	289,748	1,044
12	West Virginia Property Taxes			8,660	8,660	
13	Mississippi Property Taxes	5,248		7,582	4,170	
14	New Jersey Property Taxes			643,752	643,752	
15	Pennsylvania Property Taxes				135,229	95,533
16	Pennsylvania Franchise			4,718	28,558	
17	Federal Excise Tax	1,249,371				
18	Payroll Taxes			4,540,020	2,221,777	
19						
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40						
41	TOTAL	14,107,560	17,846,667	51,360,620	58,870,113	18,060,792

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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 (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) 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 (i) through (l) how the taxes were distributed. Report in column (l) 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 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) 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.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
		-9,843,406			-3,184,933	1
		20,805			2,312	2
1,179,999		-4,329				3
9,809,373		18,722,978				4
						5
	1,017,659	8,671,880			437,660	6
	10,197,143	12,211,025			7,297,854	7
1,027,176		723,164				8
2,495,968		8,751,456			2,156,379	9
1,738						10
		193,043				11
					8,660	12
8,660					7,582	13
					643,752	14
	39,696					15
	23,840	4,718				16
						17
3,567,614		3,816,275			723,744	18
						19
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18,090,528	11,278,338	43,267,609			8,093,010	41

Name of Respondent	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
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 262 Line No.: 1 Column: f

Adjustments to Federal Income Tax	
Income Tax Receivable Reclassification	15,327,119
Total Adjustments to Federal Income Tax	15,327,119

Schedule Page: 262 Line No.: 2 Column: f

Adjustments to State Income Tax	
Income Tax Receivable Reclassification	(45,711)
Total Adjustments to State Income Tax	(45,711)

Schedule Page: 262 Line No.: 4 Column: f

Adjustments to Maryland Property Taxes	
Construction Work in Progress Reclassification	1,806,335
Property Tax Reclassification	557,423
Total Adjustments to Maryland Property Taxes	2,363,758

Schedule Page: 262 Line No.: 5 Column: f

Adjustments to Maryland Property Taxes Other	
Property Tax Reclassification	(557,423)
Total Adjustments to Maryland Property Taxes Other	(557,423)

Schedule Page: 262 Line No.: 7 Column: f

Adjustments to Delaware Property Taxes	
Construction Work in Progress Reclassification	876,472
Total Adjustments to Delaware Property Taxes	876,472

Schedule Page: 262 Line No.: 11 Column: f

Adjustments to Virginia Property Taxes	
Construction Work in Progress Reclassification	1,044
Total Adjustments to Virginia Property Taxes	1,044

Schedule Page: 262 Line No.: 15 Column: f

Adjustments to Pennsylvania Property Taxes	
Construction Work in Progress Reclassification	95,533
Total Adjustments to Pennsylvania Property Taxes	95,533

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)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	10,160			411.4	1,523	
4	7%	498,378			411.4	74,709	
5	10%	1,306,226			411.4	195,808	
6							
7							
8	TOTAL	1,814,764				272,040	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	10% Gas Utility	189,368				40,309	
11	Total Other	189,368				40,309	
12	Account 255	2,004,132				312,349	
13							
14							
15							
16							
17							
18							
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21							
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44							
45							
46							
47							
48							

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
8,637			3
423,669			4
1,110,418			5
			6
			7
1,542,724			8
			9
149,059			10
149,059			11
1,691,783			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
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			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

OTHER DEFERRED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Special Billing	3,212,307	143	1,236,256	644,633	2,620,684
2	DE Charitable Contributions	4,772,953	426.1	1,059,455		3,713,498
3	MD Charitable Contributions	967,158	426.1	175,257		791,901
4	MFN Credits	1,389,039	144	228,691		1,160,348
5	Supplier Deposits	732,734	131	184,134	2,432	551,032
6	Merrill Creek Lease	10,935,262	418	4,317,463	4,029,447	10,647,246
7	Tower Attachment Agreements		454	1,270,686	12,050,086	10,779,400
8	Social Security Tax Deferral				2,454,515	2,454,515
9	Other	831,278			385,996	1,217,274
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	22,840,731		8,471,942	19,567,109	33,935,898

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr)	
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 7 Column: a

Refer to Note 3 "Revenue from Contracts with Customers" of accompanying "Notes to Financial Statements" for a discussion on the Contract Liabilities for the Tower Attachment Agreements.

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
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			

NOTES

Name of Respondent

Delmarva Power & Light Company

This Report Is:

(1) An Original

(2) A Resubmission

Date of Report

(Mo, Da, Yr)

03/29/2021

Year/Period of Report

End of 2020/Q4

Document Accession #: 20210329-80026

Submission Date: 03/29/2021

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
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
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
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							20
							21

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	678,734,056	49,175,719	48,555,626
3	Gas	75,414,895	5,463,969	5,395,069
4				
5	TOTAL (Enter Total of lines 2 thru 4)	754,148,951	54,639,688	53,950,695
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	754,148,951	54,639,688	53,950,695
10	Classification of TOTAL			
11	Federal Income Tax	552,346,511	27,851,598	44,080,435
12	State Income Tax	201,802,440	26,788,090	9,870,260
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
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
		VARIOUS		VARIOUS	46,961,724	726,315,873	2
		VARIOUS			5,217,969	80,701,764	3
							4
					52,179,693	807,017,637	5
							6
							7
							8
					52,179,693	807,017,637	9
							10
		VARIOUS		254	51,888,516	588,006,190	11
		VARIOUS		254	291,177	219,011,447	12
							13

NOTES (Continued)

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 9 Column: b

The following lines from 2019 FERC Form 1, column (b) are individual components of 2019 beginning balance in column (b)

Electric	952,099,714	Line 2
FAS109	(273,365,658)	Line 6
Total	678,734,056	

Gas	105,788,857	Line 3
Gas FAS109	(30,373,962)	Line 6
Total	75,414,895	

282	Electric	Gas	Total
Plant Deferred Taxes - FAS 109	688,966,595	76,551,844	765,518,439
CIAC	(27,145,839)	(3,016,205)	(30,162,044)
AFUDC Equity	8,223,269	913,697	9,136,966
Plant Deferred Taxes - Flow-through	8,690,031	965,559	9,655,590
Subtotal - p274	678,734,056	75,414,895	754,148,951

Schedule Page: 274 Line No.: 9 Column: k

282	Electric	Gas	Total
Plant Deferred Taxes - FAS 109	728,152,285	80,905,810	809,058,095
CIAC	(18,053,753)	(2,005,973)	(20,059,726)
AFUDC Equity	9,942,280	1,104,698	11,046,978
Plant Deferred Taxes - Flow-through	6,275,061	697,229	6,972,290
Subtotal - p275	726,315,873	80,701,764	807,017,637

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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric Operations	86,535,476	15,979,305	8,521,048
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	86,535,476	15,979,305	8,521,048
10	Gas			
11	Gas Operations	10,921,019	2,156,457	1,785,245
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	10,921,019	2,156,457	1,785,245
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	97,456,495	18,135,762	10,306,293
20	Classification of TOTAL			
21	Federal Income Tax	67,567,258	12,573,648	7,145,424
22	State Income Tax	29,889,237	5,562,114	3,160,869
23	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
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
							2
		VARIOUS		VARIOUS		93,993,733	3
							4
							5
							6
							7
							8
						93,993,733	9
							10
		VARIOUS		VARIOUS		11,292,231	11
							12
							13
							14
							15
							16
						11,292,231	17
							18
						105,285,964	19
							20
		VARIOUS		VARIOUS		72,995,482	21
		VARIOUS		VARIOUS		32,290,482	22
							23

NOTES (Continued)

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 19 Column: b

The following lines from 2019 FERC Form 1, column (k) are individual components of 2020 beginning balance in column (b)

Electric Operations	122,952,542	Line 3
Electric Non Operations	(1,994,141)	Line 4
FAS 109	(34,422,925)	Line 18
Total	86,535,476	

Gas Operations	16,302,191	Line 11
Gas Non Operations	(324,626)	Line 12
FAS 109	(5,056,546)	Line 18
Total	10,921,019	

283	Electric	Gas	Total
Accrued Property Taxes	\$ 4,068,403	\$ 662,298	\$ 4,730,701
Materials Reserve	(196,708)	(32,022)	(228,730)
Other Deferred Debits	1,035,874	168,631	1,204,505
Pension Asset	40,756,097	6,634,714	47,390,811
Regulatory Asset	34,820,457	2,995,874	37,816,331
Regulatory Asset - Accrued Vacation	1,716,946	279,503	1,996,449
Regulatory Asset - FERC Transmission True-up	596,646	—	596,646
Renewable Energy Credits	2,435,343	—	2,435,343
Unamortized Loss on Reacquired Debt	1,302,418	212,021	1,514,439
Subtotal p276	86,535,476	10,921,019	97,456,495

Schedule Page: 276 Line No.: 19 Column: k

283	Electric	Gas	Total
Accrued Property Taxes	\$ 4,778,464	\$ 777,889	\$ 5,556,353
Materials Reserve	(85,969)	(13,995)	(99,964)
Other Deferred Debits	2,605,709	424,185	3,029,894
Pension Asset	38,581,682	6,280,739	44,862,421
Regulatory Asset	42,933,144	3,495,359	46,428,503
Regulatory Asset - Accrued Vacation	744,315	121,167	865,482
Regulatory Asset - FERC Transmission True-up	462,758	—	462,758
Renewable Energy Credits	2,702,758	—	2,702,758
Unamortized Loss on Reacquired Debt	1,270,872	206,887	1,477,759
Subtotal p277	93,993,733	11,292,231	105,285,964

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:					
2	SFAS Electric	428,223,418	Various	67,510,884		360,712,534
3	SFAS Gas	48,332,263	Various	4,801,308		43,530,955
4	Maryland SOS:					
5	MD Energy	613,323	Various	4,264,876	3,651,553	
6	Delaware SOS:					
7	DE Energy	6,063,634	Various	20,005,217	13,941,583	
8	DE Transmission		Various	3,752,122	5,117,611	1,365,489
9	DE Administrative Costs	3,873,471	Various	8,080,284	4,206,813	
10	DE SOS Interest	412,587	431	326,401	379,068	465,254
11	DE Qualified Fuel Cell Facility	6,600,911	Various	37,926,449	38,178,566	6,853,028
12	DE Renewable Portfolio Surcharge Deferral	1,198,610	Various	24,678,571	23,479,961	
13	DE Deferred Fuel Costs-Gas		Various	15,905,150	23,287,893	7,382,743
14	DE Distribution Rate Reserve				3,131,465	3,131,465
15	DE Gas Rate Reserve		Various	658,147	2,739,723	2,081,576
16	MD Grid Resiliency Charge	4,302	Various	4,302		
17	MD Dynamic Pricing - Critical Peak Rebate Credits	218,258	407.3	384,656	804,412	638,014
18	Tax Cuts and Jobs Act	3,277,592	Various	1,754,060	310	1,523,842
19	DSM Direct Load Control Program-MD	559,927	407.3	974,403	846,963	432,487
20	DSM-Energy Efficiency Products-MD	1,060,281	407.3	1,093,254	1,050,924	1,017,951
21	MD RM54 Recovery	19,135	903	9,772		9,363
22	MD Bill Stabilization Adjustment Deferral	3,877,595	Various	86,512,397	84,120,113	1,485,311
23	SOS Deferral for FERC 494 Settlement	2,540,243	407.3	424,752		2,115,491
24	DE Electric Distribution System Improvement Charge	302,794	407.3	302,794		
25	DE Gas Distribution System Improvement Charge	418,414	407.3	418,414		
26	DE DSM - Energy Efficiency		407.3	2,326	55,615	53,289
27	Transmission Service Revenue		Various	22,115,731	31,088,376	8,972,645
28	DE Incremental COVID-19 Cost		Various	3,537,300	5,448,335	1,911,035
29	MD Incremental COVID-19 Cost		Various	2,747,100	4,144,346	1,397,246
30	Chestertown Substation Land Gain		421.1	17,604	114,888	97,284
31	Vegetation Management Spending				47,943	47,943
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	507,596,758		308,208,274	245,836,461	445,224,945

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 1 Column: a

This note applies to Schedule Page: 278 Line No.: 1 through 31, column (a): DPL records the regulatory liabilities in account 254 based on the following rate orders or legislation:

Line No.	Description of Other Regulatory Liabilities	Rate Order Docket Number or Recovery Mechanism
5	MD SOS Energy	MDPSC Case No. 8908
7	DE SOS Energy	DEPSC Docket No. 04-391
8	DE SOS Transmission	DEPSC Docket No. 04-391
9	DE SOS Administrative Costs	DEPSC Docket No. 04-391
10	DE SOS Interest	DEPSC Docket No. 04-391
11	DE Qualified Fuel Cell Facility	DEPSC Docket No. 12-173-04
12	DE Renewable Portfolio Surcharge Deferral	DEPSC Regulation Docket No. 56
13	DE Deferred Fuel Costs-Gas	DEPSC Docket No. 19-0556
14	DE Distribution Rate Reserve	DEPSC Docket No. 20-0149
15	DE Gas Rate Reserve	DEPSC Docket No. 20-0150
16	MD Grid Resiliency Charge	MDPSC Case No. 9317
17	MD Dynamic Pricing - Critical Peak Rebate Credits	MDPSC Case No. 9156
18	Tax Cuts and Jobs Act	MDPSC Case No. 9473, MDPSC Case No. 9630
19	DSM Direct Load Control Program-MD	MDPSC Case No. 9156
20	DSM-Energy Efficiency Products-MD	MDPSC Case No. 9156
21	MD RM54 Recovery	MDPSC Case No. 9455
22	MD Bill Stabilization Adjustment Deferral	MDPSC Case No. 9092, MDPSC Case No. 9093
23	SOS Deferral for FERC 494 Settlement	FERC Docket No. EL05-121-009
24	DE Electric Distribution System Improvement Charge	DEPSC Regulation Docket No. 64
25	DE Gas Distribution System Improvement Charge	DEPSC Regulation Docket No. 64
26	DE DSM - Energy Efficiency	DEPSC Docket No. 17-0985
27	Transmission Service Revenue	FERC Docket No. ER05-515
28	DE Incremental COVID-19 Cost	DEPSC Docket No. 20-0286
29	MD Incremental COVID-19 Cost	MDPSC Order No. 89636
30	Chestertown Substation Land Gain	MDPSC Case No. 9630
31	Vegetation Management Spending	MDPSC Case No. 9353

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 1 Column: d

This note applies to Schedule Page: 278 Line No.: 1 through 31, column (d): DPL amortizes its regulatory liabilities in account 254 based on the following amortization periods:

Line No.	Description of Other Regulatory Liabilities	Amortization Lives
21	MD RM54 Recovery	5 years
23	SOS Deferral for FERC 494 Settlement	10 years
30	Chestertown Substation Land Gain	3 years

Schedule Page: 278 Line No.: 2 Column: c

The following are the individual components of "Various":

\$	18,695,892	recorded to account 190; Reversal of SFAS 109 regulatory liability deferred taxes
	757,244	recorded to account 282; Reversal of SFAS 109 regulatory liability deferred taxes
	48,057,748	recorded to account 410/411
	<hr/>	
\$	67,510,884	Total

Schedule Page: 278 Line No.: 3 Column: c

The following are the individual components of "Various":

\$	1,329,044	recorded to account 190.0; Reversal of SFAS 109 regulatory liability deferred taxes
	83,018	recorded to account 282.0; Reversal of SFAS 109 regulatory liability deferred taxes
	3,389,246	recorded to account 410/411
	<hr/>	
\$	4,801,308	Total

Schedule Page: 278 Line No.: 5 Column: c

The following are the individual components of "Various":

\$	467,318	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in MD SOS - Energy line 31, pg. 232
	3,797,558	recorded to account 407.3
	<hr/>	
\$	4,264,876	Total

Schedule Page: 278 Line No.: 7 Column: c

The following are the individual components of "Various":

\$	4,883,665	recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE SOS - Energy line 27, pg. 232
	15,121,552	recorded to account 407.3
	<hr/>	
\$	20,005,217	Total

Schedule Page: 278 Line No.: 8 Column: c

The following are the individual components of "Various":

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

\$ 3,746,315 recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE SOS - Transmission line 28, pg. 232

5,807 recorded to account 407.3

\$ 3,752,122 Total

Schedule Page: 278 Line No.: 9 Column: c

The following are the individual components of "Various":

recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE SOS - Administrative Costs line 29, pg.

\$ 3,690,963 232

4,389,321 recorded to account 407.3

\$ 8,080,284 Total

Schedule Page: 278 Line No.: 11 Column: c

The following are the individual components of "Various":

\$ 2,923,666 recorded to account 142 - Billing adjustments to previously billed amounts

155,647 recorded to account 144 - Reclass of reserve on DE Qualified Fuel Cell activity

34,844,287 recorded to account 407.3

2,849 recorded to account 928

\$ 37,926,449 Total

Schedule Page: 278 Line No.: 12 Column: c

The following are the individual components of "Various":

recorded to account 182.3 - Reclass consistent with regulatory recovery position; included in DE Renewable Energy Portfolio Standards

\$ 23,126,726 from line 7, pg. 232

1,551,845 recorded to account 407.3

\$ 24,678,571 Total

Schedule Page: 278 Line No.: 13 Column: c

The following are the individual components of "Various":

\$ 5,480,678 recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Deferred Fuel Costs from line 1, pg. 232

2,224,473 recorded to account 431

8,199,999 recorded to account 805.1

\$ 15,905,150 Total

Schedule Page: 278 Line No.: 15 Column: c

The following are the individual components of "Various":

\$ 365,955 recorded to account 480

117,075 recorded to account 481

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

175,117 recorded to account 489
 \$ 658,147 Total

Schedule Page: 278 Line No.: 16 Column: c

The following are the individual components of "Various":

\$ 4,215 recorded to account 142 - Billing adjustments to previously billed amounts
 87 recorded to account 456
 \$ 4,302 Total

Schedule Page: 278 Line No.: 18 Column: c

The following are the individual components of "Various":

\$ 336,790 recorded to account 142 - Billing adjustments to previously billed amounts
 826,533 recorded to account 182.3 - Reclass of TCJA amounts, included in Transmission Service Revenue from line 4, pg. 232
 551,021 recorded to account 254 - Reclass of TCJA amounts, included in Transmission Service Revenue from line 27, pg. 278
 23,821 recorded to account 440
 15,055 recorded to account 442
 724 recorded to account 444
 116 recorded to account 456
 \$ 1,754,060 Total

Schedule Page: 278 Line No.: 22 Column: c

The following are the individual components of "Various":

recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in MD Bill Stabilization Adjustment Deferral from line 11, pg. 232
 \$ 43,266,111
 43,246,286 recorded to account 456
 \$ 86,512,397 Total

Schedule Page: 278 Line No.: 27 Column: c

The following are the individual components of "Various":

\$ 6,030,742 recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in Transmission Service Revenue line 4, pg. 232
 16,084,989 recorded to account 456.1
 \$ 22,115,731 Total

Schedule Page: 278 Line No.: 28 Column: c

The following are the individual components of "Various":

recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in DE Incremental COVID-19 Cost line 41, pg. 232
 \$ 3,418,411

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

118,889 recorded to account 426.5

\$ 3,537,300 Total

Schedule Page: 278 Line No.: 29 Column: c

The following are the individual components of "Various":

recorded to account 182.3 - Reclass consistent with regulatory recovery position, included in MD Incremental COVID-19 Cost line 42, pg.

\$ 2,696,333 232

50,767 recorded to account 426.5

\$ 2,747,100 Total

Document Accession #: 20210329-80026 Submission Date: 03/29/2021

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	652,806,401	645,138,178
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	243,382,784	266,583,434
5	Large (or Ind.) (See Instr. 4)	17,298,344	18,093,752
6	(444) Public Street and Highway Lighting	13,184,195	13,852,714
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	926,671,724	943,668,078
11	(447) Sales for Resale	6,760,725	7,782,550
12	TOTAL Sales of Electricity	933,432,449	951,450,628
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	933,432,449	951,450,628
15	Other Operating Revenues		
16	(450) Forfeited Discounts	525,420	1,682,931
17	(451) Miscellaneous Service Revenues	163,605	565,550
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	6,215,366	5,350,454
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	19,194,189	20,029,741
22	(456.1) Revenues from Transmission of Electricity of Others	153,326,754	172,224,955
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	179,425,334	199,853,631
27	TOTAL Electric Operating Revenues	1,112,857,783	1,151,304,259

Document Accession #: 20210329-80026 Submission Date: 03/29/2021

ELECTRIC OPERATING REVENUES (Account 400)

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 pages 108-109, 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.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,240,947	5,286,839	470,746	465,731	2
				3
4,886,334	5,287,655	63,077	62,594	4
1,493,349	1,484,684	315	340	5
42,377	45,087	611	619	6
				7
				8
				9
11,663,007	12,104,265	534,749	529,284	10
335,653	304,042			11
11,998,660	12,408,307	534,749	529,284	12
				13
11,998,660	12,408,307	534,749	529,284	14

Line 12, column (b) includes \$ -1,951,940 of unbilled revenues.
 Line 12, column (d) includes -91,027 MWH relating to unbilled revenues

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 17 Column: c

Items greater than \$250,000.00

Connect Charges	\$	476,145
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Schedule Page: 300 Line No.: 21 Column: b

Amounts over \$250,000

MD Bill Stabilization Adjustment	\$	3,578,180
MD Calendar Revenue Normalization		(1,185,898)
Intercompany Revenue		6,081,833
RPM Auction		3,882,106
Intracompany Power Sales		676,335
Intercompany Power Sales		764,888
Net Metering		1,269,733
Consolidated Billing and Account Management Fees		481,960
RPM Seasonal capacity Performance Auction		642,237
Price Responsive Demand Credit		2,769,287

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

Amounts over \$250,000

MD Bill Stabilization Adjustment	\$	1,528,680
MD Calendar Revenue Normalization		(946,033)
Intercompany Revenue		4,359,067
Intercompany Power Sales		800,041
RPM Auction		12,112,282
Net Metering		898,174
Consolidated Billing and Account Management Fees		270,047
Intercompany Power Sales		780,783

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
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10					
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40					
41					
42					
43					
44					
45					
46	TOTAL				

Document Accession #: 20210329-8026 Submission Date: 03/29/2021

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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales					
2	Residential	4,157,710	539,550,448	386,849	10,748	0.1298
3	Residential Time Of Use - Non Dem	2,250	270,189	173	13,006	0.1201
4	Outdoor Lighting - Residential	5,877	1,775,120	4,302	1,366	0.3020
5	Residential Space Heating	1,047,728	113,601,184	83,071	12,612	0.1084
6	Residential Time-of-Use (TOU) Pil	6,728	964,546	652	10,319	0.1434
7	Plug in Vehicle - Residential	1	93	1	1,000	0.0930
8	Small General Service	320	40,781			0.1274
9	Medium General Service	1	1,122			1.1220
10	Unbilled Revenue	20,332	789,589			0.0388
11	DE Interim Rate Subject to Refund		-1,952,405			
12	Adjustments - Duplicate Customers			-4,302		
13	Energy Credits		-2,234,266			
14	Total	5,240,947	652,806,401	470,746	11,133	0.1246
15						
16	442 - Commercial & Industrial Sal					
17	Small General Service	943,406	94,908,550	49,512	19,054	0.1006
18	Unmetered Small General Service	434	85,328	236	1,839	0.1966
19	Separately Metered Space Heating	72,219	4,367,112	2,402	30,066	0.0605
20	Separately Metered Water Heating	540	44,461	99	5,455	0.0823
21	Medium General Service	1,060,779	64,316,682	11,153	95,112	0.0606
22	Unmetered Medium General Service	37	16,855	15	2,467	0.4555
23	Large General Service	816,983	28,988,114	611	1,337,124	0.0355
24	General Services Primary	2,001,018	43,257,994	555	3,605,438	0.0216
25	Commercial Outdoor Lighting	12,696	4,147,656	3,714	3,418	0.3267
26	Com Outdoor Recreational Lighting	854	127,877	79	10,810	0.1497
27	Telecommunications Network Svc	3,591	234,565	921	3,899	0.0653
28	Residential	44	5,459			0.1241
29	Unbilled Revenue	-26,267	-1,774,882			0.0676
30	DE Interim Rate Subject to Refund		-958,470			
31	Public Utility Tax Surcharge Rev		5,831,676			
32	Adjustments - Duplicate Customers			-6,220		
33	Energy Credits		-216,193			
34	Total	4,886,334	243,382,784	63,077	77,466	0.0498
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	11,754,034	928,623,664	534,749	21,980	0.0790
42	Total Unbilled Rev.(See Instr. 6)	-91,027	-1,951,940	0	0	0.0214
43	TOTAL	11,663,007	926,671,724	534,749	21,810	0.0795

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 Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. 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) Commercial and Industrial					
2	Small General Service	6,319	514,030	122	51,795	0.0813
3	Medium General Service	9,103	469,528	53	171,755	0.0516
4	Large General Service	39,758	1,318,119	22	1,807,182	0.0332
5	General Services Primary	873,129	14,577,794	111	7,866,027	0.0167
6	General Services Transmission	648,672	803,502	8	81,084,000	0.0012
7	Industrial Outdoor Lighting	317	66,157	50	6,340	0.2087
8	Separately Metered Space Heating	144	4,396	2	72,000	0.0305
9	Unbilled Revenue	-84,093	-691,847			0.0082
10	DE Interim Rate Subject to Refund		-108,283			
11	Public Utility Tax Surcharge Rev		344,948			
12	Adjustments - Duplicate Customers			-53		
13	Total	1,493,349	17,298,344	315	4,740,790	0.0116
14						
15	444 - Public Street & Highway Lgh					
16	Outdoor Lighting	43,376	13,524,021	611	70,992	0.3118
17	DE Interim Rate Subject to Refund		-95,196			
18	Unbilled Revenue	-999	-274,800			0.2751
19	Public Utility Tax Surcharge Rev		30,170			
20	Total	42,377	13,184,195	611	69,357	0.3111
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	11,754,034	928,623,664	534,749	21,980	0.0790
42	Total Unbilled Rev.(See Instr. 6)	-91,027	-1,951,940	0	0	0.0214
43	TOTAL	11,663,007	926,671,724	534,749	21,810	0.0795

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
1,622		83,725		83,725	1
334,031		6,677,000		6,677,000	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
1,622	0	83,725	0	83,725	
334,031	0	6,677,000	0	6,677,000	
335,653	0	6,760,725	0	6,760,725	

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 (Entr Tot 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-Nuc. Power (Entr tot 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 (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
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 Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	443,978,910	469,514,497
77	(556) System Control and Load Dispatching	-6,524	1,806,887
78	(557) Other Expenses	9,444,654	7,398,780
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	453,417,040	478,720,164
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	453,417,040	478,720,164
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,976,195	5,099,320
84			
85	(561.1) Load Dispatch-Reliability	373	234,321
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	985,061	570,133
87	(561.3) Load Dispatch-Transmission Service and Scheduling	188	102,562
88	(561.4) Scheduling, System Control and Dispatch Services	-3,172	4,791
89	(561.5) Reliability, Planning and Standards Development	18,598	116,977
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	-2,070	1,191
93	(562) Station Expenses		
94	(563) Overhead Lines Expenses		
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	3,381,656	4,165,708
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	9,356,829	10,295,003
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	13,070	76,182
102	(569) Maintenance of Structures	1,092,116	40,603
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		26,590
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	8,323,338	5,862,586
108	(571) Maintenance of Overhead Lines	4,351,661	4,338,850
109	(572) Maintenance of Underground Lines	49,153	-60,203
110	(573) Maintenance of Miscellaneous Transmission Plant	440,855	506,197
111	TOTAL Maintenance (Total of lines 101 thru 110)	14,270,193	10,790,805
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,627,022	21,085,808

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
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	-405	7,993
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	-405	7,993
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 Op Exps (Total 123 and 130)	-405	7,993
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,680,723	5,616,146
135	(581) Load Dispatching	5,044,712	4,631,218
136	(582) Station Expenses	16,980	41,736
137	(583) Overhead Line Expenses	1,197,531	1,572,902
138	(584) Underground Line Expenses	2,005,518	1,917,926
139	(585) Street Lighting and Signal System Expenses	147,540	
140	(586) Meter Expenses	4,116,306	4,205,525
141	(587) Customer Installations Expenses	449,820	384,301
142	(588) Miscellaneous Expenses	13,202,541	12,742,333
143	(589) Rents	1,641,006	1,646,858
144	TOTAL Operation (Enter Total of lines 134 thru 143)	30,502,677	32,758,945
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	91,099	839,227
147	(591) Maintenance of Structures	76,656	4,452
148	(592) Maintenance of Station Equipment	4,411,331	5,250,761
149	(593) Maintenance of Overhead Lines	62,684,200	38,609,937
150	(594) Maintenance of Underground Lines	3,934,026	3,139,642
151	(595) Maintenance of Line Transformers	723,472	932,990
152	(596) Maintenance of Street Lighting and Signal Systems	1,957,852	2,279,184
153	(597) Maintenance of Meters	635,834	616,414
154	(598) Maintenance of Miscellaneous Distribution Plant	1,348,561	2,430,755
155	TOTAL Maintenance (Total of lines 146 thru 154)	75,863,031	54,103,362
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	106,365,708	86,862,307
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	1,216,041	1,223,470
161	(903) Customer Records and Collection Expenses	43,914,962	44,688,121
162	(904) Uncollectible Accounts	14,413,614	3,121,451
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	59,544,617	49,033,042

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	8,058,523	6,852,174
169	(909) Informational and Instructional Expenses	476,616	381,904
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	8,535,139	7,234,078
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	4,026,349	3,155,256
182	(921) Office Supplies and Expenses	5,169,761	4,537,463
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	66,439,481	64,762,078
185	(924) Property Insurance	673,516	423,114
186	(925) Injuries and Damages	1,197,356	831,107
187	(926) Employee Pensions and Benefits	9,307,960	11,305,901
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	2,200,314	4,168,474
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	478,062	731,040
192	(930.2) Miscellaneous General Expenses	7,056,229	7,554,140
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	96,549,028	97,468,573
195	Maintenance		
196	(935) Maintenance of General Plant	-7,488	187,098
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	96,541,540	97,655,671
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	748,030,661	740,599,063

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PJM Interconnection, LLC	EX	PJM Tariff			
2	AEP Energy Partners, Inc.	OS				
3	Axpo U.S. LLC	OS				
4	DTE Energy Trading, Inc.	OS				
5	Exelon Generation Company LLC	OS				
6	Hartree Partners LP	OS				
7	Next Era Energy Power Marketing, LLC	OS				
8	Shell Energy North America US, LP	OS				
9	TransAlta Energy Marketing (U.S.) Inc.	OS				
10	Vitol Inc.	OS				
11	PECO Borderline	OS				
12	Peak Energy Savings Credit	OS				
13	Community Renewable Energy Facility	OS				
14	AES Armenia Mountain Wind, LLC	IU				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Chestnut Flats Wind, LLC	LU				
2	Synergics Roth Rock Wind Energy, LLC	LU				
3	Other RECs	OS				
4	Altre, LLC	OS				
5	Avangrid Renewables, LLC	OS				
6	Retail Business Services LLC	OS				
7	White Oaks Solar Energy LLC	OS				
8	Delaware Sustainable Energy Utility	OS				
9	Skyview Finance Co LLC	OS				
10	SOL Systems LLC	OS				
11	SREC Trade, Inc	OS				
12	TerraForm Power LLC (Arcadia Solar, L)	OS				
13	Washington Gas (WGL Energy)	OS				
14	ICAP Energy LLC	OS				
	Total					

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.

2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	TFS Energy Futures LLC	OS				
2	0					
3	0					
4	0					
5	0		0	0	0	0
6	0		0	0	0	0
7	0		0	0	0	0
8	0		0	0	0	0
9	0		0	0	0	0
10	0		0	0	0	0
11	0		0	0	0	0
12	0		0	0	0	0
13	0		0	0	0	0
14	0		0	0	0	0
	Total					

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a 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.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
16,078			248,485	1,278,198	62,607,990	64,134,673	1
173,187				8,094,979		8,094,979	2
252,499				12,788,818		12,788,818	3
956,489				52,328,532		52,328,532	4
1,318,478				74,775,149		74,775,149	5
448,661				24,292,985		24,292,985	6
2,197,132				118,661,929		118,661,929	7
369,259				20,501,048		20,501,048	8
234,087				10,751,960		10,751,960	9
313,552				16,991,736		16,991,736	10
163				8,000		8,000	11
			811,869			811,869	12
					502,567	502,567	13
131,087				11,631,329		11,631,329	14
6,613,616			1,060,354	379,766,386	63,152,170	443,978,910	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
99,033				8,288,549		8,288,549	1
103,911				8,934,624		8,934,624	2
				814,663		814,663	3
				35,871		35,871	4
				840,845		840,845	5
				8,684		8,684	6
				2,552,076		2,552,076	7
				5,822,533		5,822,533	8
				117,000		117,000	9
				53,180		53,180	10
				29,862	3,318	33,180	11
				109,742		109,742	12
				54,094		54,094	13
					18,045	18,045	14
6,613,616			1,060,354	379,766,386	63,152,170	443,978,910	

PURCHASED POWER (Account 555) (Continued)
(Including power exchanges)

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a 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.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
					20,250	20,250	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
6,613,616			1,060,354	379,766,386	63,152,170	443,978,910	

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 1 Column: l

PJM Interconnection, LLC

Balancing Operating Reserve	\$ 55,952
Day-ahead Scheduling Reserve	(693)
Load Reconciliation for Balancing Operating Reserve	68
Load Reconciliation for Day-ahead Scheduling Reserve	36
Load Reconciliation for Non- Synchronized Reserve	6
Load Reconciliation for Reactive Services	2
Load Reconciliation for Regulation & Frequency Response Service	124
Load Reconciliation for Synchronized Reserve	35
Network Integration Transmission Service	62,507,686
Non- Synchronized Reserve	151
Reactive Services	15
Reactive Supply & Voltage Control from Generation	6,897
Regulation & Frequency Response Service	1,587
Synchronized Reserve	477
PJM Customer Payment Default	35,647
	\$ 62,607,990

Schedule Page: 326 Line No.: 2 Column: b

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

Schedule Page: 326 Line No.: 3 Column: b

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

Schedule Page: 326 Line No.: 4 Column: b

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

Schedule Page: 326 Line No.: 5 Column: a

Exelon Generation Company LLC and Delmarva Power and Light Company were both subsidiaries of Exelon Corporation as of December 31, 2020.

Schedule Page: 326 Line No.: 5 Column: b

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

Schedule Page: 326 Line No.: 6 Column: b

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

Schedule Page: 326 Line No.: 7 Column: b

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

Schedule Page: 326 Line No.: 8 Column: b

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

Schedule Page: 326 Line No.: 9 Column: b

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

Schedule Page: 326 Line No.: 10 Column: b

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

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

Schedule Page: 326 Line No.: 11 Column: a

PECO Energy Company and Delmarva Power and Light Company were both subsidiaries of Exelon Corporation as of December 31, 2020.

Schedule Page: 326 Line No.: 11 Column: b

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

Schedule Page: 326 Line No.: 12 Column: b

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

Schedule Page: 326 Line No.: 13 Column: b

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

Schedule Page: 326 Line No.: 13 Column: l

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

Schedule Page: 326 Line No.: 14 Column: b

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

Schedule Page: 326.1 Line No.: 1 Column: b

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

Schedule Page: 326.1 Line No.: 2 Column: b

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

Schedule Page: 326.1 Line No.: 3 Column: b

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

Schedule Page: 326.1 Line No.: 4 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 5 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 6 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 7 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 8 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 9 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 10 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 11 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 11 Column: l

Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.1 Line No.: 12 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 13 Column: b

Represents retirement of renewable energy credits purchased on the open-market for Delaware.

Schedule Page: 326.1 Line No.: 14 Column: l

Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.2 Line No.: 1 Column: l

Represents broker fees on purchases of renewable energy credits.

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
 2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
 3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
 4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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)
1	PJM Point to Point Trans Revenue	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
2	PJM Trans Owner Sched, Sys Control			
3	PJM Network Integration Transmission Svc			
4	Other Transmission Agreements			
5	PJM Transmission Enhancement Credits			
6	AEP Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
7	Agera Energy, LLC - DE	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
8	Agera Energy, LLC - MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
9	Alpha Gas and Electric, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
10	Ambit Energy (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
11	Ambit Energy (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
12	American Power & Gas of MD, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
13	APN Starfirst, LP	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
14	Astral Energy LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
15	Atlantic Energy MD, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
16	Atlantic Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
17	BlueStar Energy Services, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
18	BOC Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
19	Calpine Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
20	Champion Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
21	Clearview Electric (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
22	Clearview Electric (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
23	Commerce Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
24	Constellation NewEnergy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
25	Delmarva Power (DEN)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
26	Delmarva Power (MDN)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
27	Direct Energy Business Marketing, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
28	Direct Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
29	Discount Energy Group LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
30	East Coast Power & Gas of New Jersey LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
31	EDF Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
32	ELIGO	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
33	Energy Plus Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
34	Ethical Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
	TOTAL			

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
 2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
 3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
 4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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)
1	Everyday Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
2	First Point Power, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
3	First Point Power, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
4	FirstEnergy Services Corp.	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
5	Freepoint Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
6	GDF Suez Retail Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
7	GEXA Energy Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
8	GEXA Energy Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
9	Great American Power, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
10	Green Mountain Energy Company (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
11	Greenlight Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
12	Horizon Power & Light LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
13	Hudson Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
14	IDT Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
15	Inspire Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
16	Inspire Energy Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
17	Josco Energy USA LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
18	Kuehne Chemical Co	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
19	Liberty Power Corp	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
20	Liberty Power Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
21	Major Energy Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
22	Maryland Gas & Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
23	MidAmerican Energy Services, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
24	MP2 Energy NE LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
25	NextEra Energy Services Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
26	NextEra Energy Services Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
27	Palmco Power LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
28	Palmco Power LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
29	Park Power	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
30	PBF Power Marketing, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
31	Perigee Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
32	Plymouth Rock Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
33	PP&L EnergyPlus Co , LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
34	PP&L EnergyPlus Co , LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
	TOTAL			

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

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)
1	Public Power of MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
2	Reliant Energy Northeast LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
3	ResCom Energy LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
4	Residents Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
5	RPA Energy, Inc.	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
6	SFE Energy Maryland, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
7	SmartEnergy Holdings, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
8	SmartEnergy Holdings, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
9	Star Energy Partners, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
10	Starion Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
11	Stategic Energy LTD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
12	StateWise Energy Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
13	Stream Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
14	Stream Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
15	SunSea	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
16	Sunwave USA Holdings	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
17	Texas Retail Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
18	Titan Gas, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
19	Tomorrow Energy Corp	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
20	UGI Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
21	Viridian Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
22	Washington Gas Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
23	XOOM Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
24	XOOM Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
OATT						1
						2
						3
						4
						5
PJM Tariff	DPL SYSTEM	DPL SYSTEM		19,631		6
PJM Tariff	DPL SYSTEM	DPL SYSTEM		11		7
PJM Tariff	DPL SYSTEM	DPL SYSTEM		30		8
PJM Tariff	DPL SYSTEM	DPL SYSTEM		218		9
PJM Tariff	DPL SYSTEM	DPL SYSTEM		7,181		10
PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,508		11
PJM Tariff	DPL SYSTEM	DPL SYSTEM		7,992		12
PJM Tariff	DPL SYSTEM	DPL SYSTEM		80		13
PJM Tariff	DPL SYSTEM	DPL SYSTEM		4		14
PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,434		15
PJM Tariff	DPL SYSTEM	DPL SYSTEM		3,658		16
PJM Tariff	DPL SYSTEM	DPL SYSTEM		86,815		17
PJM Tariff	DPL SYSTEM	DPL SYSTEM		221,837		18
PJM Tariff	DPL SYSTEM	DPL SYSTEM		220,204		19
PJM Tariff	DPL SYSTEM	DPL SYSTEM		76,787		20
PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,604		21
PJM Tariff	DPL SYSTEM	DPL SYSTEM		7,764		22
PJM Tariff	DPL SYSTEM	DPL SYSTEM		41,521		23
PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,654,038		24
PJM Tariff	DPL SYSTEM	DPL SYSTEM		-16,283		25
PJM Tariff	DPL SYSTEM	DPL SYSTEM		-47,245		26
PJM Tariff	DPL SYSTEM	DPL SYSTEM		12,522		27
PJM Tariff	DPL SYSTEM	DPL SYSTEM		557,075		28
PJM Tariff	DPL SYSTEM	DPL SYSTEM		458		29
PJM Tariff	DPL SYSTEM	DPL SYSTEM		111,241		30
PJM Tariff	DPL SYSTEM	DPL SYSTEM		55,059		31
PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,287		32
PJM Tariff	DPL SYSTEM	DPL SYSTEM		3,985		33
PJM Tariff	DPL SYSTEM	DPL SYSTEM		38,865		34
			0	6,100,817		0

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
PJM Tariff	DPL SYSTEM	DPL SYSTEM		2		1
PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,485		2
PJM Tariff	DPL SYSTEM	DPL SYSTEM		132		3
PJM Tariff	DPL SYSTEM	DPL SYSTEM		191		4
PJM Tariff	DPL SYSTEM	DPL SYSTEM		71,459		5
PJM Tariff	DPL SYSTEM	DPL SYSTEM		180,410		6
PJM Tariff	DPL SYSTEM	DPL SYSTEM		324,135		7
PJM Tariff	DPL SYSTEM	DPL SYSTEM		30,076		8
PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,671		9
PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,749		10
PJM Tariff	DPL SYSTEM	DPL SYSTEM		263		11
PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,607		12
PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,804		13
PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,223		14
PJM Tariff	DPL SYSTEM	DPL SYSTEM		7,893		15
PJM Tariff	DPL SYSTEM	DPL SYSTEM		217		16
PJM Tariff	DPL SYSTEM	DPL SYSTEM		25		17
PJM Tariff	DPL SYSTEM	DPL SYSTEM		62,886		18
PJM Tariff	DPL SYSTEM	DPL SYSTEM		22,400		19
PJM Tariff	DPL SYSTEM	DPL SYSTEM		87,348		20
PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,068		21
PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,122		22
PJM Tariff	DPL SYSTEM	DPL SYSTEM		132,165		23
PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,439		24
PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,098		25
PJM Tariff	DPL SYSTEM	DPL SYSTEM		314		26
PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,409		27
PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,850		28
PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,070		29
PJM Tariff	DPL SYSTEM	DPL SYSTEM		341,468		30
PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,475		31
PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,393		32
PJM Tariff	DPL SYSTEM	DPL SYSTEM		494,884		33
PJM Tariff	DPL SYSTEM	DPL SYSTEM		63,157		34
			0	6,100,817		0

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.

6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.

7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.

8. Report in column (i) and (j) the total megawatthours received and delivered.

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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
PJM Tariff	DPL SYSTEM	DPL SYSTEM		29,683		1
PJM Tariff	DPL SYSTEM	DPL SYSTEM		223,777		2
PJM Tariff	DPL SYSTEM	DPL SYSTEM		462		3
PJM Tariff	DPL SYSTEM	DPL SYSTEM		13,554		4
PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,376		5
PJM Tariff	DPL SYSTEM	DPL SYSTEM		13,659		6
PJM Tariff	DPL SYSTEM	DPL SYSTEM		26,166		7
PJM Tariff	DPL SYSTEM	DPL SYSTEM		11,050		8
PJM Tariff	DPL SYSTEM	DPL SYSTEM		1,108		9
PJM Tariff	DPL SYSTEM	DPL SYSTEM		3,991		10
PJM Tariff	DPL SYSTEM	DPL SYSTEM		143,678		11
PJM Tariff	DPL SYSTEM	DPL SYSTEM		314		12
PJM Tariff	DPL SYSTEM	DPL SYSTEM		7,413		13
PJM Tariff	DPL SYSTEM	DPL SYSTEM		4,629		14
PJM Tariff	DPL SYSTEM	DPL SYSTEM		644		15
PJM Tariff	DPL SYSTEM	DPL SYSTEM		48		16
PJM Tariff	DPL SYSTEM	DPL SYSTEM		31,695		17
PJM Tariff	DPL SYSTEM	DPL SYSTEM		2,263		18
PJM Tariff	DPL SYSTEM	DPL SYSTEM		5,940		19
PJM Tariff	DPL SYSTEM	DPL SYSTEM		16,793		20
PJM Tariff	DPL SYSTEM	DPL SYSTEM		6,884		21
PJM Tariff	DPL SYSTEM	DPL SYSTEM		560,682		22
PJM Tariff	DPL SYSTEM	DPL SYSTEM		9,932		23
PJM Tariff	DPL SYSTEM	DPL SYSTEM		20,907		24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	6,100,817		0

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
		2,091,348	2,091,348	1
		1,432,139	1,432,139	2
		143,781,450	143,781,450	3
		4,415,331	4,415,331	4
		1,606,486	1,606,486	5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	0	153,326,754	153,326,754	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
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				21
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				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	0	153,326,754	153,326,754	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
				1
				2
				3
				4
				5
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				30
				31
				32
				33
				34
0	0	153,326,754	153,326,754	

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 1 Column: m

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

Schedule Page: 328 Line No.: 2 Column: m

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

Schedule Page: 328 Line No.: 3 Column: m

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

Schedule Page: 328 Line No.: 4 Column: m

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.

Schedule Page: 328 Line No.: 5 Column: m

Revenue from Transmission Enhancements.

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					
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34					
35					
36					
37					
38					
39					
40	TOTAL				

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to-Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

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

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	306,065
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	Trustee Fees	158,921
7	Board of Director Expenses	72,521
8	Research, Development, and Demonstration,	
9	includings Memberships	325,204
10	DE Environmental & Low Income and MD Universal Fund	6,177,959
11	Credit Card Accruals	15,559
12	Miscellaneous	
13		
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16		
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46	TOTAL	7,056,229

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).

2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,411,346		3,411,346
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	46,656,401				46,656,401
8	Distribution Plant	72,138,121				72,138,121
9	Regional Transmission and Market Operation					
10	General Plant	10,279,462				10,279,462
11	Common Plant-Electric	3,903,687		6,120,325		10,024,012
12	TOTAL	132,977,671		9,531,671		142,509,342

B. Basis for Amortization Charges

Consistent with the preceding year, Electric Intangible Plant Computer Software is amortized for a five year period using a straight line basis.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

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	33,067	65.00		1.54	R3	
14	352	73,841	55.00	-20.00	2.00	S5	
15	353	633,290	50.00	-10.00	2.10	R2	
16	354	73,958	55.00	-25.00	2.27	R3	
17	355	574,332	38.00	-45.00	3.68	S0.5	
18	356	312,192	50.00	-50.00	2.60	S1	
19	357	6,076	40.00		2.50	R4	
20	358	62,642	40.00		2.50	R3	
21	359	1,189	50.00		2.00	R3	
22	SUBTOTAL	1,770,587					
23	Distribution						
24	360.2 DE	3,584	70.00		1.05	R4	
25	360.2 MD	4,086	60.00		1.31	R2	
26	361 DE	25,255	65.00	-10.00	1.27	R4	
27	361 MD	24,504	60.00	-15.00	1.79	R2	
28	362 DE	253,133	45.00	-20.00	2.08	R2	
29	362 MD	183,148	52.00	-25.00	2.02	R2.5	
30	364 DE	115,897	55.00	-100.00	2.25	R2	
31	364 MD	121,827	55.00	-125.00	2.99	R2	
32	365 DE	182,040	55.00	-100.00	1.53	R1.5	
33	365 MD	209,420	58.00	-100.00	2.30	R0.5	
34	366 DE	23,921	70.00	-5.00	0.84	S3	
35	366 MD	961	50.00		1.65	R3	
36	367 DE	222,103	52.00	-40.00	1.82	R3	
37	367 MD	177,657	40.00	-20.00	2.83	R3	
38	368 DE	315,578	45.00	-50.00	1.77	R2	
39	368 MD	271,321	35.00	-50.00	3.57	R1	
40	369.1 DE	18,847	65.00	-120.00	0.81	R4	
41	369.1 MD	8,862	65.00	-75.00	2.17	R4	
42	369.2 DE	97,934	55.00	-60.00	1.36	S3	
43	369.2 MD	87,151	45.00	-25.00	2.21	S6	
44	370 DE	14,134	25.00	-3.00	2.77	L0.5	
45	370 MD	6,172	30.00		4.72	S3	
46	370.1 DE	68,520	15.00	-3.00	8.13	S2	
47	370.1 MD	43,439	15.00		11.18	S3	
48	371.1 DE	30,130	18.00	-40.00	8.20	R2	
49	371.1 MD	11,380	42.00	-50.00	2.83	S1.5	
50	373 DE	58,444	38.00	-30.00	0.95	R2	

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

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	373 MD	13,270	33.00	-30.00	3.81	SC	
13							
14	SUBTOTAL	2,592,718					
15	GENERAL						
16	390 DE	26,421	50.00	-10.00	1.01	R3	
17	390 MD	630	35.00	-10.00	3.48	R1.5	
18	391.1 DE	2,306	19.00	5.00	5.38	L2	
19	391.2 DE	691	20.00		5.65	SQ	
20	391.1 MD	1,455	15.00		6.68	SQ	
21	391.3 MD	5,012	5.00		10.00	SQ	
22	391.3 DE	484	5.00		21.49	SQ	
23	393 DE	9,125	25.00		19.74	SQ	
24	394 DE	-1	25.00		6.32	SQ	
25	394.1 DE		36.00		2.78	L1	
26	394 MD	8,098	15.00		6.67	SQ	
27	395 DE		20.00		15.46	SQ	
28	397 MD	24,004	35.00	-10.00	3.09	S3	
29	397 DE	68,226	25.00		4.13	L3	
30	397.1 MD	24,891	15.00		6.90	S3	
31	397.1 DE	21,079	15.00		6.98	S2	
32	397.3 MD	41,860	15.00		6.67	SQ	
33	397.3 DE	3,384	15.00		6.89	SQ	
34	398 DE	1,041	20.00		5.74	SQ	
35	398 MD	1,951	15.00		6.67	SQ	
36	392.2 DE	319	10.00		8.40	S2.5	
37	392.3 MD	206	14.00		6.33	S1.5	
38							
39	SUBTOTAL	241,182					
40	COMMON						
41	390.3	46,268	75.00	-5.00	0.80	S1.5	
42	390.3a	11,957	75.00	-5.00	0.73	S1.5	
43	390.3b	781	40.00	-20.00	-0.09	R2	
44	391.1	5,207	20.00		5.38	SQ	
45	391.3	9,613	5.00		36.45	SQ	
46	393	120	25.00		6.27	SQ	
47	394		25.00		6.56	SQ	
48	397.1	5,085	20.00	5.00	4.75	L2	
49	397.1a	4,524	15.00		6.63	S2	
50	397.3	19,898	15.00		0.09	SQ	

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

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	398	7,878	20.00		5.22	SQ	
13	398.1a	2,224	20.00		5.74	SQ	
14	SUBTOTAL	113,555					
15	TOTAL	4,718,042					
16							
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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.

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Delaware				
2	2016 DE Base Rate Case 16-0649		193	193	
3	2017 DE Base Rate Case 17 0977		43,082	43,082	
4	2020 DE Rate Case No 20-0149		758,064	758,064	
5	General Regulation Legal		146,159	146,159	
6	DE Electric DSIC		1,038	1,038	
7					
8	Maryland				
9	2019 MD Base Rate Case 9630		467,186	467,186	
10	2016 MD Base Rate Case 9424		8,792	8,792	
11	2017 MD Base Rate Case 9455		26,250	26,250	
12	PC44 DPL MD		256,011	256,011	
13	Regulatory Commission Expense		4,303	4,303	
14	MD Grid Future Proceeding		2,362	2,362	
15	General Regulation Legal		234,562	234,562	
16					
17	Transmission:				
18	ER05-515 Annual Rate Updates FERC Transmission		252,312	252,312	
19	0				
20	0				
21	0				
22	0				
23	0				
24	Regulatory Tax Assessment				
25	0				
26	0				
27					
28					
29					
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36					
37					
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45					
46	TOTAL		2,200,314	2,200,314	

REGULATORY COMMISSION EXPENSES (Continued)

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 column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than \$25,000) may be grouped.

EXPENSES INCURRED DURING YEAR			AMORTIZED DURING YEAR				
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
0	0			0			1
Electric	928	193		0			2
Electric	928	43,082		0			3
Electric	928	758,064		0			4
Electric	928	146,159		0			5
Electric	928	1,038		0			6
Electric	928			0			7
				0			8
Electric	928	446,942		928	20,244		9
Electric	928			928	8,792		10
Electric	928	6,937		928	19,313		11
Electric	928	256,011		0			12
Electric	928	4,303		0			13
Electric	928	2,362		0			14
Electric	928	234,562		0			15
				0			16
				0			17
Electric	928	252,312		0			18
Electric	928			0			19
Electric	928			0			20
Electric	928			0			21
				0			22
							23
Electric	928						24
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		2,151,965			48,349		46

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 & 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 & 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:

- | | |
|--|--|
| A. Electric R, D & D Performed Internally: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1	A-2 and A-3	Other - 5 Projects (less than \$50K)
2	B-1	Membership - EPRI
3	B-1	Low Carbon Resource Initiative - EPRI
4	B-4	Membership - CU Boulder College of Engineering (CU Foundation)
5	B-4	Membership - Power Systems Engineering Research Center (ASU)
6	B-4	Membership - NEETRAC (Georgia Tech Research Corp)
7	B-4	Membership - Electric Drive Transportation Association
8	B-4	Membership - Centre for Energy Advancement through Technical Innovation
9	B-4	Membership - Northeast Gas Association
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25		
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30		
31		
32		
33	Total	
34		
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
- (3) Research Support to Nuclear Power Groups
- (4) Research Support to Others (Classify)
- (5) Total Cost Incurred

3. Include in column (c) all R, D & 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 & 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 & 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 & 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.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
18,714		930.2	18,714		1
	201,782	930.2	201,782		2
	37,640	930.2	37,640		3
	940	930.2	940		4
	6,215	930.2	6,215		5
	10,423	930.2	10,423		6
	9,704	930.2	9,704		7
	35,931	930.2	35,931		8
	3,855	930.2	3,855		9
					10
					11
					12
					13
					14
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					17
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					30
					31
					32
18,714	306,490		325,204		33
					34
					35
					36
					37
					38

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	1,844,417		
49	Administrative and General	2,555		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	2,102,708		
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)	473,240		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	741,883		
56	Transmission (Lines 35 and 47)	1,444,196		
57	Distribution (Lines 36 and 48)	8,760,004		
58	Customer Accounts (Line 37)	555,276		
59	Customer Service and Informational (Line 38)	131,579		
60	Sales (Line 39)	132,614		
61	Administrative and General (Lines 40 and 49)	929,758		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	13,168,550	364,217	13,532,767
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	59,175,113	2,527,551	61,702,664
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	44,789,068	2,620,074	47,409,142
69	Gas Plant	6,237,507	315,473	6,552,980
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	51,026,575	2,935,547	53,962,122
72	Plant Removal (By Utility Departments)			
73	Electric Plant	4,566,029	302,912	4,868,941
74	Gas Plant	361,199	17,080	378,279
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,927,228	319,992	5,247,220
77	Other Accounts (Specify, provide details in footnote):			
78	Expenses from Merchandising, Jobbing & Contracting Work - 416	2,800,787	119,421	2,920,208
79	Expenses of Non-Utility Operations - 417.1	8,634	32	8,666
80	Donations - 426.1	14,503	202	14,705
81	Exp. For Certain Civic, Political & Related Activities	109,069	4,432	113,501
82	Other Deductions - 426.5	382,976	26,155	409,131
83				
84				
85				
86				
87				
88				
89				
90	Plant Held for Future - 105	2,969		2,969
91				
92				
93				
94				
95	TOTAL Other Accounts	3,318,938	150,242	3,469,180
96	TOTAL SALARIES AND WAGES	118,447,854	5,933,332	124,381,186

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to 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	51,404,330	12,742,526	(73,804)	-	64,073,052
389.1	1,621,110	-	-	-	1,621,110
390.3	55,979,758	3,234,891	(8,500)	-	59,206,149
391.1	5,206,517	-	-	-	5,206,517
391.3	6,503,843	3,230,819	(54,890)	-	9,679,772
393	120,006	-	-	-	120,006
394	5,350,960	-	(603,589)	-	4,747,371
397	24,130,877	414,483	-	-	24,545,360
398	8,947,806	1,153,582	-	-	10,101,388
	160,001,707	20,776,301	(740,783)	-	180,037,225

Acct	Electric	Gas	Total Common Utility Plant	E = 83.08% G = 16.92%
301	611,884	124,616	736,500	
303	53,231,892	10,841,160	64,073,052	
389.1	1,346,818	274,292	1,621,110	
390.3	49,188,469	10,017,680	59,206,149	
391.1	4,325,574	880,943	5,206,517	
391.3	8,041,954	1,637,818	9,679,772	
393	99,701	20,305	120,006	
394	3,944,116	803,255	4,747,371	
397	20,392,285	4,153,075	24,545,360	
398	8,392,233	1,709,155	10,101,388	
	149,574,926	30,462,299	180,037,225	

Accumulated Provision for Depreciation of Common Utility Plant

COMMON UTILITY PLANT AND EXPENSES

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

DPL 12/31/2020			
	Total Common	Electric	Gas
Balance at Beginning of Year	70,181,690	58,271,858	11,909,832
Depreciation Provision for the Year Charged to:			
403 Depreciation Expense	4,565,716	3,793,197	772,519
Net Charges for Plant Retired:			
Book Charges for Plant Retired	(666,979)	(554,126)	(112,853)
Cost of Removal, Net of Salvage	42,466	35,281	7,185
Other Debit or Credit Items:			
Transfers / Adjustments	(189,923)	(157,788)	(32,135)
Gain from Sale	-	-	-
Electric & Gas Allocator Adjustment	-	35,091	(35,091)
Balance at End of Year	73,932,970	61,423,513	12,509,457

Accumulated Provision for Amortization of Common Utility Plant DPL 12/31/2020			
	Total Common	Electric	Gas
Balance at Beginning of Year	24,681,454	20,493,011	4,188,443
Depreciation Provision for the Year Charged to:			
404 Amortization Expense	7,421,862	6,166,083	1,255,779
Net Charges for Plant Retired:			
Book Charges for Plant Retired	(73,805)		
Cost of Removal, Net of Salvage			
Other Debit or Credit Items			
Transfers / Adjustments	-	-	-
Electric & Gas Allocator Adjustment		(48,976)	(24,828)
Balance at End of Year	32,029,511	26,610,118	5,419,394

Name of Respondent Document Accession #: 20210329-8006 Delmarva Power & Light Company	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 <u>2020/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

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

Document Accession #: 20210329-8026

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)	475,929	786,177	1,064,785	1,313,845
3	Net Sales (Account 447)	(1,941,259)	(3,402,593)	(4,403,169)	(6,677,000)
4	Transmission Rights	18,436,997	35,183,767	48,828,150	62,507,686
5	Ancillary Services	2,174	27,450	52,381	64,656
6	Other Items (list separately)				
7	Demand	92,713	165,803	206,796	248,486
8					
9					
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40					
41					
42					
43					
44					
45					
46	TOTAL	17,066,554	32,760,604	45,748,943	57,457,673

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	6,613,616	MWH	5,138	12,714,433	MWH	1,445,298
2	Reactive Supply and Voltage		MWH	6,897			
3	Regulation and Frequency Response		MWH	1,711			
4	Energy Imbalance						
5	Operating Reserve - Spinning		MWH	511			
6	Operating Reserve - Supplement		MWH	1,424			
7	Other		MWH	55,537			
8	Total (Lines 1 thru 7)	6,613,616		71,218	12,714,433		1,445,298

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 2 Column: b
 The number of units reported on Line #2, Column (b) is 6,613,616 MWH.

Schedule Page: 398 Line No.: 3 Column: b
 The number of units reported on Line #3, Column (b) is 6,613,616 MWH.

Schedule Page: 398 Line No.: 5 Column: b
 The number of units reported on Line #5, Column (b) is 6,613,616 MWH.

Schedule Page: 398 Line No.: 6 Column: b
 The number of units reported on Line #6, Column (b) is 6,613,616 MWH.

Schedule Page: 398 Line No.: 7 Column: b
 The number of units reported on Line #7, Column (b) is 6,613,616 MWH.

Schedule Page: 398 Line No.: 7 Column: d

Other Ancillary Services Purchased is as follows:

Balancing Operating Reserve	\$ 56,020
Day-ahead Scheduling Reserve	(657)
Non-Synchronized Reserve	157
Reactive Services	17
	\$ 55,537

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.

NAME OF SYSTEM:

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)
1	January	3,136	21	800	2,228	908				
2	February	2,917	21	800	2,022	895				
3	March	2,442	1	700	1,715	727				
4	Total for Quarter 1				5,965	2,530				
5	April	2,165	1	900	1,417	748				
6	May	2,633	29	1700	1,787	846				
7	June	3,442	23	1800	2,440	1,002				
8	Total for Quarter 2				5,644	2,596				
9	July	4,029	20	1800	2,997	1,032				
10	August	3,726	2	1800	2,787	939				
11	September	3,471	3	1800	2,483	988				
12	Total for Quarter 3				8,267	2,959				
13	October	2,176	22	1900	1,413	763				
14	November	2,628	19	800	1,836	792				
15	December	2,796	18	1800	1,978	818				
16	Total for Quarter 4				5,227	2,373				
17	Total Year to Date/Year				25,103	10,458				

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr)	
Delmarva Power & Light Company		/ /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 400 Line No.: 1 Column: d

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.

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).

NAME OF SYSTEM:

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

Document Accession #: 20210329-80026

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	11,663,007
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	1,622
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	334,031
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	17,136
7	Other		27	Total Energy Losses	698,637
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	12,714,433
9	Net Generation (Enter Total of lines 3 through 8)				
10	Purchases	6,613,616			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	6,100,817			
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	6,100,817			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	12,714,433			

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).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	1,161,999	34,774	3,136	21	800
30	February	1,036,639	32,251	2,917	21	800
31	March	973,509	33,196	2,442	1	700
32	April	864,472	33,304	2,165	1	900
33	May	885,022	31,476	2,633	29	1700
34	June	1,096,403	18,690	3,442	23	1800
35	July	1,396,127	13,620	4,029	20	1800
36	August	1,275,132	16,261	3,726	2	1800
37	September	1,013,319	18,388	3,471	3	1800
38	October	900,571	26,908	2,176	22	1900
39	November	938,637	36,909	2,628	19	800
40	December	1,172,603	39,876	2,796	18	1800
41	TOTAL	12,714,433	335,653			

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Delmarva Power & Light Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) / /	2020/Q4
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 29 Column: f

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.

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	Plant Name: (b)	Plant Name: (c)
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)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	0	0
20	Fuel	0	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	0	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	0	0
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U. S. of A. 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.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
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)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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 the 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."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
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)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

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.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
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			19
			20
			21
			22
			23
			24
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			36
			37
			38

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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24						
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42						
43						
44						
45						
46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
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						24
						25
						26
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						29
						30
						31
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						42
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						44
						45
						46

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.
- 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.
- Report data by individual lines for all voltages if so required by a State commission.
- 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	500 KV Line (wholly owned)		500.00	500.00	SC Steel	15.55		3
2								
3	230 KV Lines		230.00	230.00	Various	387.52	83.64	27
4								
5	138 KV Lines		138.00	138.00	Various	503.91	82.53	83
6								
7	69 KV Lines		69.00	69.00	Various	556.19	13.02	73
8								
9	Underground Lines	5.38 mi. / 138, 2.09 mi/69				7.47		10
10	SEE DETAIL ON	FOLLOWING PAGES						
11	JOINT VENTURES							
12								
13	EHV System		500.00	500.00	steel tower	127.00		1
14	LDV System		500.00	500.00	stl/alm tower	154.00		6
15	SE System		500.00	500.00	steel tower			
16	(15)-(17) Above							
17	Non-Specific Line charges							
18	(All KV Inclusive)							
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35	Line Expenses							
36					TOTAL	2,643.09	345.36	313

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.
- 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.
- Report data by individual lines for all voltages if so required by a State commission.
- 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Keeney	Steele	230.00	230.00	Steel towers		57.20	1
2	Indian River	Piney Grove	230.00	230.00	Wood H-frame	25.83		1
3	Red Lion	Silver Run	230.00	230.00	Steel poles	11.89		1
4	Silver Run	Cedar Creek	230.00	230.00	Steel poles	9.08		1
5	Cedar Creek	Milford	230.00	230.00	Wood H-frame	42.84		1
6	Red Lion	Silver Run	230.00	230.00	steel poles	7.58	4.31	1
7	Silver Run	Cartanza	230.00	230.00	steel poles	25.83		1
8	Cartanza	Milford	230.00	230.00	steel poles	26.50		1
9	Milford	Indian River	230.00	230.00	steel poles	26.37		1
10	Milford	Cool Spring	230.00	230.00	wood H frame	14.95		1
11	Indian River	Cool Spring	230.00	230.00	steel poles	11.54		1
12	Milford	Steele	230.00	230.00	wood H frame	23.39		1
13	Colora	Nottingham (Bradford)	230.00	230.00	steel towers	1.76		1
14	Colora	Crest	230.00	230.00	steel poles	7.57		1
15	Claymont Sub	Linwood	230.00	230.00	steel poles	0.99		1
16	Edgemoor	Linwood	230.00	230.00	steel poles		8.10	1
17	Colora	Conowingo	230.00	230.00	steel poles	1.92		1
18	Crest	Cecil	230.00	230.00	steel poles	8.45		1
19	Keeney	Steele	230.00	230.00	steel towers	57.07		1
20	Keeney	Harmony	230.00	230.00	steel poles	6.14		1
21	Keeney	Red Lion	230.00	230.00	steel towers	8.05		1
22	Harmony	Edge Moor	230.00	230.00	steel poles	11.87		1
23	Keeney	Harmony	230.00	230.00	steel poles	9.30	0.20	1
24	Edge Moor	Claymont	230.00	230.00	steel poles	7.07		1
25	Hay Road	Red Lion	230.00	230.00	steel poles	10.72	13.83	1
26	Cartanza	Garrison	230.00	230.00	steel poles	2.63		1
27	Steele	Vienna	230.00	230.00	wood H frame	28.17		1
28	Church	Steele	138.00	138.00	wood H frame	25.69		1
29	Milford	Milford City	138.00	138.00	wood poles	0.24		1
30	Nelson	Indian River	138.00	138.00	wood H frame	21.41		1
31	Cheswold	Felton	138.00	138.00	wood poles	14.38		1
32	Indian River	Robinsonville	138.00	138.00	wood poles	11.74		1
33	Robinsonville	Rehoboth	138.00	138.00	steel poles	6.90		1
34	Vienna	Nelson	138.00	138.00	wood H frame	13.68		1
35	Felton	South Harrington	138.00	138.00	wood poles	8.49		1
36					TOTAL	2,643.09	345.36	313

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.
- 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.
- Report data by individual lines for all voltages if so required by a State commission.
- 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Vienna	Vienna (AT20)	138.00	138.00	wood poles	0.17		1
2	Easton	Steele	138.00	138.00	steel poles	23.62		1
3	Loretto	Kings Creek	138.00	138.00	wood H frame	7.18		1
4	Kings Creek	Pocomoke	138.00	138.00	wood H frame	9.14		1
5	Indian River	Bishop	138.00	138.00	steel poles	12.33		1
6	Indian River	Bishop	138.00	138.00	steel poles	7.24	5.18	1
7	Oak Hall	Eastern Shore Solar	138.00	138.00	steel poles	0.07		1
8	Church	Carville	138.00	138.00	steel poles	0.13	17.58	1
9	Kings Creek	Great Bay	138.00	138.00	steel poles	0.10		1
10	Ocean Bay	138th Street	138.00	138.00	wood poles	2.97		1
11	138th Street	Bethany	138.00	138.00	steel poles	6.13		1
12	Roxana	Bethany	138.00	138.00	wood H frame	3.65		1
13	Indian River	Roxana	138.00	138.00	wood H frame	8.54		1
14	Indian River AT20	Indian River 138	138.00	138.00	steel poles	0.26		1
15	Indian River AT22	Indian River 138	138.00	138.00	steel poles	0.29		1
16	Steele	Hillsboro	138.00	138.00	wood H frame	7.24		1
17	New Church	Oak Hall	138.00	138.00	wood poles	3.68		1
18	Piney Grove	New Church	138.00	138.00	wood H frame	21.80		1
19	New Church	Oak Hall	138.00	138.00	wood H frame	3.56		1
20	Indian River	Conaway	138.00	138.00	wood H frame	8.50		1
21	Conaway	North Seaford	138.00	138.00	wood H frame	16.94		1
22	Clayton	Cheswold	138.00	138.00	wood poles	6.63		1
23	N. Seaford	South Harrington	138.00	138.00	wood poles	16.22		1
24	Clayton	Demec	138.00	138.00	steel poles	0.69		1
25	Farmview	Milford	138.00	138.00	wood poles	2.44		1
26	Farmview	South Harrington	138.00	138.00	wood poles	7.73		1
27	Piney Grove	Loretto	138.00	138.00	wood H frame	9.49		1
28	Bishop	Worcester	138.00	138.00	wood H frame	5.33		1
29	Loretto	Vienna	138.00	138.00	wood H frame	19.44		1
30	Bishop	St Martins Neck Ocean Bay	138.00	138.00	wood H frame	9.97		1
31	Pocomoke	Oak Hall	138.00	138.00	wood H frame	8.57		1
32	Hillsboro	Wye Mills	138.00	138.00	wood H frame	8.59		1
33	Wattsville	Oak Hall	138.00	138.00	steel poles	3.91		1
34	Glasgow	Mt Pleasant	138.00	138.00	steel poles	10.99		1
35	Red Lion West	Reybold	138.00	138.00	steel poles	1.11		1
36					TOTAL	2,643.09	345.36	313

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	New Castle	Town of New Castle	138.00	138.00	steel poles	0.40		1
2	Edge Moor	Brandywine	138.00	138.00	steel poles	2.52		1
3	Edge Moor	Christiana	138.00	138.00	steel towers	2.56	0.15	1
4	Keeney	Churchmans	138.00	138.00	steel poles	6.05		1
5	Churchmans	Basin Road	138.00	138.00	steel poles	0.93	2.50	1
6	Mt Pleasant	Towsend	138.00	138.00	steel poles	11.27		1
7	Keeney	Glasgow	138.00	138.00	steel poles	3.33		1
8	New Castle	Hares Corner	138.00	138.00	steel poles	3.68		1
9	Hares corner	Red Lion	138.00	138.00	steel poles	4.48	0.68	1
10	Christiana	New Castle	138.00	138.00	steel towers	0.75	3.46	1
11	Basin Road	Bear	138.00	138.00	wood poles	4.69		1
12	Keeney	Sunset Lake	138.00	138.00	wood poles	2.27		1
13	Red Lion	Reybold	138.00	138.00	steel poles	0.14	1.11	1
14	Glasgow	Cecil	138.00	138.00	steel poles	5.24		1
15	Basin Road	Kiamensi	138.00	138.00	steel towers	3.20		1
16	Basin Road	New Castle	138.00	138.00	steel towers	0.11	2.94	1
17	Keeney	Chapel Street	138.00	138.00	steel poles	1.27	2.82	1
18	Harmony	Chapel Street	138.00	138.00	steel poles	3.32		1
19	Keeney EHV	Keeney 138	138.00	138.00	steel poles	0.25		1
20	Carrcroft	Talleyville	138.00	138.00	wood poles	3.56		1
21	Edgemoor	Carrcroft	138.00	138.00	steel towers	0.84	2.81	1
22	Motiva	Reybold	138.00	138.00	wood poles	0.08		1
23	Carrcroft	West Wilmington	138.00	138.00	steel towers	4.33		1
24	West Wilmington	Silverbrook	138.00	138.00	steel poles	1.97		1
25	Harmony	Kiamensi	138.00	138.00	steel poles	4.23		1
26	Kiamensi	Silverbrook	138.00	138.00	steel towers	2.70	1.00	1
27	Brandywine	Carrcroft	138.00	138.00	steel towers	1.36	2.87	1
28	Red Lion	Bloom Energy	138.00	138.00	steel poles	0.44		1
29	Cedar Creek	Clayton	138.00	138.00	wood poles	9.23		1
30	Towsend	Church	138.00	138.00	steel poles	12.32		1
31	Kiamensi	Milltown	138.00	138.00	wood poles	1.40	1.31	1
32	Milltown	Valley Road	138.00	138.00	wood poles	4.60		1
33	Valley Road	Hockessin	138.00	138.00	wood poles	1.78		1
34	Kiamensi	Hockessin	138.00	138.00	wood poles	6.26		1
35	Reybold	Lums Pond	138.00	138.00	wood poles	8.22		1
36					TOTAL	2,643.09	345.36	313

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. 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.
6. 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.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Lums pond	Mt Pleasant	138.00	138.00	wood poles	9.74		1
2	Bear	Sunset Lake	138.00	138.00	wood poles	5.31		1
3	Glasgow	Mt Pleasant	138.00	138.00	steel poles	11.10		1
4	Carville	Wye Mills	138.00	138.00	steel poles	0.12	7.93	1
5	Piney Grove	Wattsville	138.00	138.00	steel poles	0.71	30.19	1
6								
7								
8								
9								
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11								
12								
13								
14								
15								
16								
17								
18								
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21								
22								
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24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,643.09	345.36	313

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	842,230	23,318,422	24,160,652					1
								2
	15,382,105	227,992,289	243,374,394					3
								4
	11,248,373	445,114,487	456,362,860					5
								6
	7,548,675	262,055,057	269,603,732					7
								8
	9,713	67,452,676	67,462,389					9
								10
								11
								12
	184,167	1,752,004	1,936,171					13
	181,238	952,788	1,134,026					14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
					7,693,142	202,221	7,895,363	35
	35,396,501	1,028,637,723	1,064,034,224		7,693,142	202,221	7,895,363	36

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1590 ACSR								1
1590 ACSR								2
1590 ACSR								3
1590 ACSR								4
1590 ACSR								5
1590 ACSR								6
1590 ACSR								7
1590 ACSR								8
1590 ACSR								9
1590 ACSR								10
1590 ACSR								11
1590 ACSR								12
795 ACSR								13
1590 ACSR								14
1590 ACSR								15
1590 ACSR								16
795 ACSR								17
1590 ACSR								18
1590 ACSR								19
1590 ACSR								20
1590 ACSR								21
1590 ACSR								22
1590 ACSR								23
1590 ACSR								24
1590 ACSR								25
1590 ACSR								26
1590 ACSR								27
1590 ACSR								28
336.4 ACSR								29
477 ACSR								30
954 ACSR								31
954 ACSR								32
954 ACSR								33
954 ACSR								34
954 ACSR								35
	35,396,501	1,028,637,723	1,064,034,224		7,693,142	202,221	7,895,363	36

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TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1590 ACSR								1
996.2 ACSR								2
954 ACSR								3
954 ACSR								4
1590 ACSR								5
1590 ACSR								6
954 ACSR								7
1590 ACSR								8
954 ACSR								9
966.2 ACSR								10
954 ACSR								11
954 ACSR								12
954 ACSS & 954								13
1590 ACSR								14
2000 KCMIL CU								15
954 ACSR								16
954 ACSR								17
477 ACSR								18
556.5 ACSS								19
954 ACSR								20
954 ACSR								21
954 ACSR								22
954 ACSR								23
954 ACSR								24
954 ACSR								25
954 ACSR								26
477 ACSR								27
954 ACSR								28
1590 ACSR								29
954 ACSR								30
954 ACSR								31
954 ACSR								32
954 ACSR								33
1590 ACSR								34
954 ACSR								35
	35,396,501	1,028,637,723	1,064,034,224		7,693,142	202,221	7,895,363	36

Document Accession #: 20210329-80026 Submission Date: 03/29/2021

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
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9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR								1
954 ACSR								2
954 ACSR								3
1590 ACSR								4
636 ACSR								5
1590 ACSR								6
636 ACSR								7
954 Phoenix								8
954 Rail								9
636 ACSR								10
954 ACSR								11
954 ACSR								12
954 ACSR								13
1590 ACSR & 768.S								14
954 ACSR								15
954 ACSR								16
954 ACSR								17
336 ACSR								18
1590 ACSR								19
477 AA								20
954 ACSR								21
954 ACSR								22
954 ACSR								23
954 ACSR								24
1590 ACSR								25
954 ACSR								26
954 ACSR								27
954 ACSR								28
954 ACSR								29
636 ACSR								30
954 ACSR								31
954 ACSR								32
954 ACSR								33
954 ACSR								34
954 ACSR								35
	35,396,501	1,028,637,723	1,064,034,224		7,693,142	202,221	7,895,363	36

Document Accession #: 20210329-80026 Submission Date: 03/29/2021

TRANSMISSION LINE STATISTICS (Continued)

7. 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)
8. 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.
9. 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.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR								1
954 ACSR								2
1590 ACSR								3
1590 ACSR								4
1590 ACSR								5
								6
								7
								8
								9
								10
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								32
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								34
								35
	35,396,501	1,028,637,723	1,064,034,224		7,693,142	202,221	7,895,363	36

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 35 Column: o

TRANSMISSION LINE AGREEMENTS:

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

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

	Percentage
Public Service Electric & Gas	42.55
Atlantic City Electric	13.90
Delmarva Power & Light	1.00
PECO Energy Co.	42.55
Total	100.00

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

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

LDV (500KV) Summary:

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

Schedule Page: 422.1 Line No.: 32 Column: f

Includes 3.15 miles of steel poles as well.

Schedule Page: 422.2 Line No.: 13 Column: i

Includes 954 ACSR as well.

Schedule Page: 422.2 Line No.: 15 Column: f

Includes 0.14 miles of UG as well.

Schedule Page: 422.2 Line No.: 15 Column: i

Includes 1949 ACSS as well.

Schedule Page: 422.2 Line No.: 30 Column: f

Includes 2.81 miles of UG as well.

Schedule Page: 422.2 Line No.: 30 Column: i

Includes KCMIL AL as well.

Schedule Page: 422.3 Line No.: 14 Column: i

Includes 768.2 ACSS as well.

Schedule Page: 422.3 Line No.: 27 Column: f

Includes 1.24 miles of UG as well.

Schedule Page: 422.3 Line No.: 27 Column: i

Includes KCMIL AL as well.

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
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31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
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Document Accession #: 20210329-8026 Submission Date: 03/29/2021

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Andora - Cecil, MD	Distribution - (U)	34.00	4.00	
2	Appleton - Cecil, MD	Distribution - (U)	34.00	4.00	
3	Basin Road - New Castle, DE	Transmission - (U)	138.00	69.00	
4	Basin Road - New Castle, DE	Distribution - (U)	69.00	12.00	
5	Basin Road - New Castle, DE	Distribution - (U)	138.00	12.00	
6	Beaglin - Salisbury, MD	Distribution - (U)	69.00	25.00	
7	Bear - New Castle, DE	Distribution - (U)	138.00	12.00	
8	Bear - New Castle, DE	Distribution - (U)	138.00	34.00	
9	Bethany - Bethany, DE	Distribution - (U)	138.00	12.00	
10	Bethany - Bethany, DE	Transmission - (U)	138.00	69.00	
11	Bethany - Bethany, DE	Distribution - (U)	69.00	12.00	
12	Bishop - Bishopville, MD	Distribution - (U)	138.00	25.00	
13	Blue Ball Road - Elkton, MD	Distribution - (U)	34.00	4.00	
14	Bohemia - Cecil, MD	Distribution - (U)	34.00	4.00	
15	Bozman - Bozman, MD	Distribution - (U)	69.00	25.00	
16	Brandywine - Wilmington, DE	Distribution - (U)	138.00	12.00	
17	Bridgeville - Bridgeville, DE	Distribution - (U)	69.00	12.00	
18	Brookside - Pencader, DE	Distribution - (U)	34.00	12.00	
19	Calvert - Cecil, MD	Distribution - (U)	34.00	4.00	
20	Cambridge - Cambridge, MD	Distribution - (U)	69.00	12.00	
21	Carrcroft - Brandywine, DE	Transmission - (U)	138.00	69.00	
22	Carrcroft - Brandywine, DE	Distribution - (U)	138.00	34.50	
23	Centreville, MD	Distribution - (U)	138.00	25.00	
24	Cathers - Cecil, MD	Distribution - (U)	34.00	4.36	
25	Cayots - Cecil, MD	Distribution - (U)	34.00	4.00	
26	Cecil - Cecil, MD	Distribution - (U)	138.00	34.00	
27	Cecil - Cecil, MD	Distribution - (U)	230.00	34.00	
28	Cecil - Cecil, MD	Transmission - (U)	230.00	138.00	
29	Cecil - Cecil, MD	Distribution - (U)	34.00	4.16	
30	Cedar Creek - New Castle, DE	Transmission - (U)	230.00	138.00	
31	Cedar Creek - New Castle, DE	Distribution - (U)	138.00	25.00	
32	Cedar Neck - Cedar Neck, DE	Distribution - (U)	69.00	12.47	
33	Centreville - Centreville, MD	Distribution - (U)	69.00	12.47	
34	Chapel St - Newark, DE	Distribution - (U)	138.00	34.00	
35	Chapel St - Newark, DE	Distribution - (U)	34.50	12.00	
36	Charles - Cecil, MD	Distribution - (U)	34.00	4.00	
37	Chesapeake City - Cecil, MD	Distribution - (U)	34.00	4.00	
38	Chestertown - Chestertown, MD	Distribution - (U)	69.00	25.00	
39	Chestnut Run - Christiana, DE	Distribution - (U)	34.00	12.00	
40	Cheswold - Cheswold, DE	Distribution - (U)	138.00	25.00	

Document Accession #: 20210329-8026 Submission Date: 03/29/2021

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Cheswold - Cheswold, DE	Transmission - (U)	138.00	69.00	
2	Christiana - Wilmington, DE	Distribution - (U)	138.00	12.00	
3	Church - Millington, MD	Transmission - (U)	138.00	69.00	
4	Church - Millington, MD	Distribution - (U)	69.00	25.00	
5	Churchmans - New Castle, DE	Distribution - (U)	138.00	12.00	
6	Claymont - Brandywine, DE	Transmission - (U)	230.00	69.00	
7	Clayton - Clayton, DE	Distribution - (U)	25.00	4.00	
8	Clayton - Clayton, DE	Distribution - (U)	138.00	24.00	
9	Colora - Cecil, MD	Distribution - (U)	230.00	34.00	
10	Cool Spring - Milton, DE	Transmission - (U)	230.00	69.00	
11	Cowlane - Cecil, MD	Distribution - (U)	34.00	4.00	
12	Crest, Cecil Co., MD	Distribution - (U)	230.00	34.00	
13	Crisfield - Crisfield, MD	Distribution - (U)	69.00	25.00	
14	Crisfield - Crisfield, MD	Distribution - (U)	69.00	12.47	
15	Crothers Road, Cecil Co., MD	Distribution - (U)	34.00	4.00	
16	Culver - Ocean City, MD	Distribution - (U)	69.00	25.00	
17	Darley - Brandwine, DE	Distribution - (U)	69.00	12.47	
18	Darley - Brandwine, DE	Distribution - (U)	69.00	34.00	
19	Darlington - Harford, MD	Distribution - (U)	34.00	4.36	
20	Delaware City- Delaware City, DE	Distribution - (U)	138.00	12.47	
21	Delaware City- Delaware City, DE	Transmission - (U)	138.00	69.00	
22	Dublin - Harford, MD	Distribution - (U)	34.00	4.16	
23	Dupont Experimental- Wilmington, DE	Distribution - (U)	34.00	12.00	
24	E New Market - East New Market, MD	Distribution - (U)	69.00	12.47	
25	Easton - Easton, MD	Transmission - (U)	138.00	69.00	
26	Edgemoor - Brandywine, DE	Distribution - (U)	138.00	12.47	
27	Edgemoor - Brandywine, DE	Transmission - (U)	138.00	69.00	
28	Edgemoor - Brandywine, DE	Transmission - (U)	230.00	138.00	
29	Edgemoor - Brandywine, DE	Distribution - (U)	69.00	12.00	
30	Elkneck - Cecil, MD	Distribution - (U)	34.00	4.00	
31	Elkton - Cecil, MD	Distribution - (U)	34.00	4.00	
32	Faulk Road - Brandywine, DE	Distribution - (U)	34.00	12.00	
33	Felton - Felton, DE	Distribution - (U)	138.00	25.00	
34	Five Points - Five Points, DE	Distribution - (U)	69.00	12.47	
35	Foundry - Cecil, MD	Distribution - (U)	34.00	4.00	
36	Frankford - Frankford, DE	Distribution - (U)	138.00	25.00	
37	Fruitland - Fruitland, MD	Distribution - (U)	69.00	25.00	
38	Gallion - Harford, MD	Distribution - (U)	34.00	4.00	
39	Gilpin - Cecil, MD	Distribution - (U)	34.00	4.00	
40	Glasgow - New Castle, DE	Distribution - (U)	138.00	12.47	

Document Accession #: 20210329-8026 Submission Date: 03/29/2021

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Glasgow - New Castle, DE	Distribution - (U)	138.00	34.50	
2	Glen - Cecil, MD	Distribution - (U)	34.00	4.16	
3	Grace Street - St. Michaels, MD	Distribution - (U)	69.00	12.00	
4	Grasonville - Grasonville, MD	Distribution - (U)	69.00	25.00	
5	Greenbank - Cecil, MD	Distribution - (U)	34.00	4.00	
6	Hances - Cecil, MD	Distribution - (U)	34.00	4.00	
7	Harbeson - Harbeson, DE	Distribution - (U)	69.00	25.00	
8	Hares Corner - New Castle, DE	Distribution - (U)	138.00	12.00	
9	Harford - Harford, MD	Distribution - (U)	34.00	4.16	
10	Harmony - White Clay, DE	Transmission - (U)	230.00	138.00	
11	Harmony - White Clay, DE	Distribution - (U)	138.00	34.50	
12	Harmony - White Clay, DE	Distribution - (U)	138.00	12.47	
13	Harrington - Harrington, DE	Distribution - (U)	69.00	25.00	
14	Harris - Cecil, MD	Distribution - (U)	34.00	4.00	
15	Hebron - Hebron, MD	Distribution - (U)	69.00	25.00	
16	Hillsboro - Hillsboro, MD	Distribution - (U)	138.00	25.00	
17	Hockessin - Mill Creek, DE	Distribution - (U)	138.00	12.00	
18	Indian River - Millsboro, DE	Transmission - (U)	230.00	138.00	
19	Indian River - Millsboro, DE	Transmission - (U)	138.00	69.00	
20	Irishtown - Cecil, MD	Distribution - (U)	34.00	4.00	
21	Jacktown - Cambridge, MD	Distribution - (U)	69.00	12.00	
22	Keeney EHV - Pencader Hd, DE	Transmission - (U)	500.00	230.00	
23	Keeney EHV - Pencader Hd, DE	Transmission - (U)	230.00	138.00	
24	Keeney EHV - Pencader Hd, DE	Distribution - (U)	230.00	34.50	
25	Keeney 138kV - Pencader Hd, DE	Distribution - (U)	138.00	12.47	
26	Kenney - Snow Hill, MD	Distribution - (U)	69.00	25.00	
27	Keeney- Newark, DE	Distribution - (U)	69.00	12.00	
28	Kent - Dover, DE	Distribution - (U)	69.00	25.00	
29	Kiamensi - Christiana Rd, DE	Transmission - (U)	138.00	69.00	
30	Kiamensi - Christiana Rd, DE	Distribution - (U)	138.00	34.50	
31	Kilby - Cecil, MD	Distribution - (U)	34.00	4.00	
32	Kings Creek - Princess Anne, MD	Transmission - (U)	138.00	69.00	
33	Kings Creek - Princess Anne, MD	Distribution - (U)	138.00	24.94	
34	Laurel - Laurel, DE	Distribution - (U)	69.00	12.00	
35	Leslie - Cecil, MD	Distribution - (U)	34.00	4.00	
36	Liberty Grove - Cecil, MD	Distribution - (U)	34.00	4.16	
37	Little Falls - Little Falls, DE	Distribution - (U)	34.00	12.00	
38	Loretto - Princess Anne, MD	Transmission - (U)	138.00	69.00	
39	Lums Pond - New Castle, DE	Distribution - (U)	138.00	25.00	
40	Lynch - Lynch, MD	Distribution - (U)	69.00	24.94	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Macton - Harford, MD	Distribution - (U)	34.00	4.00	
2	Maridel - Ocean City, MD	Distribution - (U)	69.00	12.00	
3	Massey - Galena, MD	Distribution - (U)	69.00	24.94	
4	Mechanics - Cecil, MD	Distribution - (U)	34.00	4.00	
5	Mermaid - New Castle, DE	Distribution - (U)	34.50	12.00	
6	Mermaid - New Castle, DE	Distribution - (U)	138.00	12.00	
7	Middle - Cecil, MD	Distribution - (U)	34.00	4.00	
8	Midway - Rehoboth, DE	Distribution - (U)	69.00	12.00	
9	Milford - Milford, DE	Distribution - (U)	138.00	24.94	
10	Milford - Milford, DE	Transmission - (U)	230.00	138.00	
11	Milford Crossroads - Mill Cr Rd, DE	Distribution - (U)	34.00	12.00	
12	Millsboro - Millsboro, DE	Distribution - (U)	69.00	25.00	
13	Milltown - Mill Cr Rd, DE	Distribution - (U)	138.00	12.00	
14	Montchanin - Brandywine, DE	Distribution - (U)	34.00	12.00	
15	Mt. Hermon - Salisbury, MD	Distribution - (U)	69.00	25.00	
16	Mount Pleasant - New Castle, DE	Distribution - (U)	138.00	25.00	
17	Naamans - Brandywine, DE	Distribution - (U)	69.00	12.00	
18	Nelson - Delmar, DE	Transmission - (U)	138.00	69.00	
19	Nelson - Delmar, DE	Distribution - (U)	138.00	12.00	
20	Nesbitt - Cecil, MD	Distribution - (U)	34.00	4.00	
21	New Castle, DE	Distribution - (U)	69.00	12.00	
22	Normira - Cecil, MD	Distribution - (U)	34.00	4.00	
23	North East - Cecil, MD	Distribution - (U)	34.00	4.00	
24	N Salisbury - Salisbury, MD	Distribution - (U)	69.00	25.00	
25	N Seaford - Seaford, DE	Transmission - (U)	138.00	69.00	
26	N Seaford - Seaford, DE	Distribution - (U)	69.00	12.47	
27	Oak Hall - Oak Hall, VA	Transmission - (U)	138.00	69.00	
28	Ocean Bay - Ocean City, MD	Distribution - (U)	138.00	12.47	
29	Ocean Bay - Ocean City, MD	Transmission - (U)	138.00	69.00	
30	Ocean City - Ocean City, MD	Distribution - (U)	69.00	12.47	
31	138th St - Ocean City, MD	Transmission - (U)	138.00	12.47	
32	Otsego - Cecil, MD	Distribution - (U)	34.00	4.00	
33	Pemberton - Salisbury, MD	Distribution - (U)	69.00	25.00	
34	Perch - Cecil, MD	Distribution - (U)	34.00	4.00	
35	Piney Grove - Salisbury, MD	Transmission - (U)	138.00	69.00	
36	Piney Grove - Salisbury, MD	Transmission - (U)	230.00	138.00	
37	Pocomoke - Pocomoke, MD	Distribution - (U)	138.00	12.47	
38	Point Breeze - Brandywine, DE	Distribution - (U)	34.00	12.00	
39	Porter's Bridge - Cecil, MD	Distribution - (U)	34.00	4.00	
40	Preston-Preston	Distribution - (U)	69.00	12.50	

Document Accession #: 20210329-8026 Submission Date: 03/29/2021

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			Primary (c)	Secondary (d)	Tertiary (e)
1	Price Sub - Price, MD	Distribution - (U)	69.00	25.00	
2	Prince-Cecil, MD	Distribution - (U)	34.00	4.00	
3	Red Lion-New Castle, DE	Transmission - (U)	500.00	230.00	
4	Red Lion-New Castle, DE	Distribution - (U)	138.00	25.00	
5	Red Lion Sub-Pencader Hd, DE	Transmission - (U)	230.00	138.00	
6	Rehoboth Sub-Rehoboth, DE	Transmission - (U)	138.00	69.00	
7	Rehoboth Sub-Rehoboth, DE	Distribution - (U)	69.00	12.50	
8	Reybold Sub-Red Lion Hd, DE	Transmission - (U)	138.00	69.00	
9	Reybold Sub-Red Lion Hd, DE	Distribution - (U)	138.00	12.00	
10	Rising Sun-Cecil, MD	Distribution - (U)	34.00	4.00	
11	Sharptown-Sharptown, MD	Distribution - (U)	69.00	12.50	
12	Silverbrook Sub, DE	Distribution - (U)	138.00	34.50	
13	Silverside Rd Sub-Brandywine Hd, DE	Distribution - (U)	69.00	12.00	
14	Silverside Rd Sub-Brandywine Hd, DE	Distribution - (U)	69.00	34.50	
15	S Harrington Sub-Harrington, DE	Transmission - (U)	138.00	69.00	
16	Steele-Denton, MD	Transmission - (U)	230.00	138.00	
17	Steele-Denton, MD	Distribution - (U)	138.00	25.00	
18	Stevensville, MD	Distribution - (U)	69.00	25.00	
19	Stockton-Stockton, MD	Distribution - (U)	69.00	25.00	
20	Sunset Lake Sub-Pencader Hd, DE	Distribution - (U)	138.00	12.00	
21	Sunset Lake Sub-Pencader Hd, DE	Distribution - (U)	138.00	25.00	
22	Sussex Sub-Georgetown, DE	Distribution - (U)	69.00	12.50	
23	Talleyville Sub-Brandywine Hd, DE	Distribution - (U)	34.50	12.00	
24	Talleyville, DE	Distribution - (U)	138.00	12.00	
25	Theodore-Cecil, MD	Distribution - (U)	34.00	4.00	
26	Todd-Hurlock, MD	Distribution - (U)	69.00	25.00	
27	Todd-Hurlock, MD	Distribution - (U)	69.00	12.00	
28	Todd-Hurlock, MD	Distribution - (U)	72.00	25.00	
29	Townsend Sub-New Castle Hd, DE	Distribution - (U)	138.00	25.00	
30	Trappe-Trappe, MD	Distribution - (U)	69.00	12.50	
31	Triumph-Cecil, MD	Distribution - (U)	34.00	4.00	
32	Vienna-Vienna, MD	Transmission - (U)	138.00	69.00	
33	Vienna-Vienna, MD-Local	Distribution - (U)	69.00	12.50	
34	Vienna-Vienna, MD	Transmission - (U)	230.00	138.00	
35	Walnut-Cecil, MD	Distribution - (U)	34.00	4.00	
36	Wattsville-Wattsville, VA	Transmission - (U)	138.00	69.00	
37	West Sub-Christiana Hd, DE	Distribution - (U)	69.00	34.50	
38	West Sub-Christiana Hd, DE	Distribution - (U)	69.00	12.00	
39	West Cambridge, MD	Distribution - (U)	69.00	12.00	
40	West Wilmington-Wilm, DE	Distribution - (U)	138.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	Whiteford-Harford, MD	Distribution - (U)	34.00	4.00	
2	Woodlawn-Cecil, MD	Distribution - (U)	34.00	4.00	
3	Worcester-Berlin, MD	Distribution - (U)	69.00	25.00	
4	Worcester-Berlin, MD	Transmission - (U)	138.00	69.00	
5	Wye Mills, Wye Mills, MD	Transmission - (U)	138.00	69.00	
6	Wye Mills, Wye Mills, MD	Distribution - (U)	69.00	25.00	
7	Spare Transformer 1	Transmission - (U)	500.00	230.00	
8	Spare Transformer 2	Transmission - (U)	230.00	138.00	
9	Spare Transformer 3	Transmission - (U)	230.00	69.00	
10	Spare Transformer 4	Transmission - (U)	230.00	34.50	
11	Spare Transformer 5	Transmission - (U)	230.00	16.00	
12	Spare Transformer 6	Transmission - (U)	138.00	69.00	
13	Spare Transformer 7	Transmission - (U)	138.00	34.50	
14	Spare Transformer 8	Transmission - (U)	138.00	25.00	
15	Spare Transformer 9	Transmission - (U)	138.00	16.00	
16	Spare Transformer 10	Transmission - (U)	138.00	12.00	
17	Spare Transformer 11	Distribution - (U)	69.00	34.50	
18	Spare Transformer 12	Distribution - (U)	69.00	25.00	
19	Spare Transformer 13	Distribution - (U)	69.00	12.00	
20	Spare Transformer 14	Distribution - (U)	69.00	7.56	
21	Spare Transformer 15	Distribution - (U)	34.50	12.00	
22	Spare Transformer 16	Distribution - (U)	34.50	4.00	
23					
24	Mobile D1		138.00	25.00	
25	Mobile D2		69.00	25.00	
26	Mobile D3		34.00	12.00	
27	Mobile D4		138.00	25.00	
28	Mobile D5		69.00	25.00	
29	Mobile D6		138.00	25.00	
30	Mobile D7		69.00	25.00	
31	Mobile D8		69.00	12.00	
32	Mobile D9		138.00	12.00	
33	Mobile D10		138.00	25.00	
34	Mobile D11		138.00	25.00	
35	Total		24340.50	7281.86	
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
4	1			0		1
6	2			0		2
84	1			0		3
22	1			0		4
22	1		69kV Capacitor Bank	1	24	5
112	2			0		6
112	2			0		7
84	1			0		8
40	1			0		9
200	1		138kV Capacitor Bank	1	29	10
20	1		69kV Capacitor Bank	2	34	11
38	1			0		12
4	1			0		13
8	2			0		14
56	2			0		15
168	2		12kV Capacitor Bank	2	14	16
37	4		69kV Capacitor Bank	2	30	17
44	2			0		18
4	1			0		19
60	2		69kV Capacitor Bank	1	12	20
112	1			0		21
84	1		34kV Capacitor Bank	2	29	22
76	2			0		23
8	2			0		24
8	2			0		25
100	1			0		26
90	1			0		27
336	1			0		28
8	2			0		29
336	1		230kV Reactor	1	40	30
28	1			0		31
75	2			0		32
33	4			0		33
84	1		138kV Capacitor Bank	2	29	34
84	1		34kV Capacitor Bank	1	6	35
8	2			0		36
4	1			0		37
45	2		69kV Capacitor Bank	1	8	38
42	2		12kV Capacitor Bank	2	6	39
25	1		138kV Capacitor Bank	1	19	40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
225	1		0			1
168	3		12kV Capacitor Bank	6	36	2
325	2		0			3
63	2		0			4
112	2		0			5
312	2		0			6
4	1		0			7
57	2		0			8
220	2		0			9
336	1		0			10
4	1		0			11
224	2		0			12
28	1		0			13
14	1		0			14
4	1		0			15
20	1		0			16
74	2		0			17
50	1		0			18
4	1		0			19
100	1		0			20
112	1		0			21
8	2		0			22
62	3		0			23
6	1		0			24
150	1		0			25
62	1		0			26
212	2		0			27
336	1		0			28
206	3		0			29
4	1		0			30
16	4		0			31
44	2		0			32
25	1		0			33
40	2		0			34
4	1		0			35
28	1		0			36
67	2		0			37
8	2		0			38
4	1		0			39
25	1		0			40

Document Accession #: 20210329-8026 Submission Date: 03/29/2021

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
84	1			0		1
8	2			0		2
33	6			0		3
50	2			0		4
4	1			0		5
4	1			0		6
63	2			0		7
93	2			0		8
8	2			0		9
896	2			0		10
134	2			0		11
112	2			0		12
50	2			0		13
4	1			0		14
56	2			0		15
25	1			0		16
112	2			0		17
1236	3			0		18
225	1			0		19
4	1			0		20
38	1			0		21
1680	2			0		22
448	1			0		23
84	1			0		24
38	1			0		25
13	1			0		26
28	1			0		27
45	2			0		28
112	1			0		29
106	2			0		30
4	1			0		31
224	2			0		32
50	2			0		33
57	2		69kV Capacitor Bank	1	20	34
4	1			0		35
8	2			0		36
2	1			0		37
106	2			0		38
87	2			0		39
28	1			0		40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
8	2		0			1
40	2		0			2
28	1		69kV Capacitor Bank	1	8	3
3	1		0			4
22	1		0			5
56	1		0			6
8	2		0			7
43	2		0			8
50	1		0			9
336	1		0			10
44	2		0			11
66	2		0			12
90	2		0			13
44	2		0			14
89	2		0			15
79	2		0			16
112	2		0			17
100	2		0			18
48	1		0			19
4	1		12kV Capacitor Bank	2	12	20
122	3		0			21
4	1		0			22
4	1		0			23
84	2		0			24
187	2		0			25
38	1		0			26
200	2		0			27
80	2		0			28
200	1		0			29
75	2		0			30
75	2		0			31
8	2		0			32
27	1		0			33
4	1		0			34
300	1		0			35
225	1		0			36
40	2		0			37
42	2		0			38
4	1		0			39
7	1		0			40

Document Accession #: 20210329-8026 Submission Date: 03/29/2021

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
28	1			0		1
4	1			0		2
1569	2			0		3
28	1			0		4
672	2			0		5
200	1			0		6
66	2			0		7
112	1			0		8
74	2			0		9
7	2			0		10
7	1			0		11
144	2			0		12
66	2			0		13
56	1			0		14
100	1			0		15
892	3			0		16
38	1			0		17
63	2			0		18
20	2			0		19
74	2			0		20
17	1			0		21
68	2			0		22
44	2			0		23
56	1			0		24
4	1			0		25
25	1			0		26
12	1			0		27
25	1			0		28
56	1			0		29
20	1			0		30
4	1			0		31
200	2			0		32
3	1			0		33
400	1			0		34
4	1			0		35
335	1			0		36
112	2			0		37
112	2			0		38
38	1			0		39
168	2			0		40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
4	1			0		1
4	1			0		2
66	2			0		3
200	1			0		4
450	2			0		5
56	2			0		6
576		2				7
1120		3				8
336		1				9
112		1				10
150		1				11
337		2				12
224		3				13
122		3				14
150		1				15
234		4				16
56		1				17
84		2				18
114		3				19
11		2				20
42		2				21
13		5				22
						23
25		1				24
12		1				25
20		1				26
12		1				27
40		1				28
28		1				29
30		1				30
27		1				31
21		1				32
30		1				33
30		1				34
26492	322	47		29	356	35
						36
						37
						38
						39
						40

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account 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	114,577,718
4				
5	Exelon Business Services Company (EBSC)			
6	Centralized Support Services	EBSC	Various	104,830,135
7				
8	Atlantic City Electric Co (ACE)			
9	Materials	ACE	Various	386,117
10	Mutual Assistance	ACE	Various	35,817
11	Meter Transfers	ACE	Various	32,869
12	Building Services (use of building space)	ACE	184	5,092
13				
14	Potomac Electric Power Company (Pepco)			
15	Materials	Pepco	Various	335,736
16	Mutual Assistance	Pepco	Various	180,471
17				
18	Atlantic Southern Properties (ASP)			
19	Building Services (use of building space)	ASP	184	2,094
20	Non-power Goods or Services Provided for Affiliate			
21	Atlantic City Electric Co (ACE)			
22	Materials	ACE	154 / 163 / 921/ 923	2,017,072
23	Mutual Assistance	ACE	456	856,208
24	Extra-High Voltage (EHV) Transmission Agreement	ACE	456.1	78,288
25	Building Services (use of building space)	ACE	Various	21,198
26	Field Operations Services	ACE	415	4,831
27				
28	Baltimore Gas & Electric Co. (BGE)			
29	Mutual Assistance	BGE	456	14,995
30	Extra-High Voltage (EHV) Transmission Agreement	BGE	456.1	234,864
31	Materials	BGE	154/163	569
32				
33	Commonwealth Edison Company (ComEd)			
34	Mutual Assistance	ComEd	456	1,002,140
35	Materials	ComEd	154/163	5,246
36				
37	Potomac Electric Power Company (PEPCO)			
38	Materials	PEPCO	154/163/921	1,437,422
39	Extra-High Voltage (EHV) Transmission Agreement	PEPCO	456.1	234,864
40	Building Services (use of building space)	PEPCO	Various	5,369
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2	PECO Energy Company (PECO)			

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Field Operations Services	PECO	921	91,466
4	Extra-High Voltage (EHV) Transmission Agreement	PECO	571	36,492
5	Information Technology Services	PECO	Various	31,446
6	Materials	PECO	921	7,371
7				
8	Baltimore Gas & Electric Co. (BGE)			
9	Regulatory Services	BGE	928	156,667
10	Information Technology Services	BGE	Various	150,723
11	Mutual Assistance	BGE	Various	22,089
12	Materials	BGE	154	16,554
13				
14	Commonwealth Edison Company (ComEd)			
15	Mutual Assistance	ComEd	Various	2,342,589
16	Information Technology Services	ComEd	Various	111,087
17	Materials	ComEd	921	6,251
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	PECO Energy Company (PECO)			
22	Mutual Assistance	PECO	456	488,946
23	Extra-High Voltage (EHV) Transmission Agreement	PECO	456.1	287,052
24	Materials	PECO	154	5,573
25				
26	Exelon Business Services Company (EBSC)			
27	Building Lease (use of building space)	EBSC	Various	852,273
28	Vehicle Services	EBSC	456	16,536
29	Materials		154/163	292
30				
31	PHI Service Company (PHISCO)			
32	Building Lease (Use of Office space)	PHISCO	Various	2,745,077
33	Vehicle Services	PHISCO	456	895,046
34	Materials	PHISCO	154/163/ 921	19,636
35				
36	Constellation Solar MC, LLC (CSM)			
37	Fiber Connection Services	CSM	Various	87,854
38				
39	Exelon Generation Corporation (EGC)			
40	Building Lease (Use of Office space)	EGC	454	354,914
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2	Constellation Power Source Gen (CPSG)			
3	Mechanical and Electrical Industrial Services	CPSG	Various	608,374
4				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5	Exelon Clearsight, LLC (EC)			
6	Inspection Services	EC	Various	62,240
7	Mutual Assistance	EC	Various	1,040
8				
9	Exelon PowerLabs, LLC (EPL)			
10	Calibration and Engineering Services	EPL	807	1,522
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21				
22				
23				
24				
25				
26				
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28				
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38				
39				
40				
41				
42				

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 2 Column: a

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, interconnection planning and arrangements, 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.

Schedule Page: 429 Line No.: 3 Column: c

PHISCO Centralized Support Services to DPL:

FERC	Amount
107	\$ 14,698,702
108	1,524,831
163	623,420
182.3	934,362
184	1,758,136
254	44,996
416	41,808
419	(52,609)
426.1	411,789
426.3	1
426.4	257,625
426.5	533,378
430	111
431	52,243
556	988
557	841,268
560	1,514,774
561.1	117
561.2	17,528
561.3	109
561.5	16,185
566	1,175,365
568	232
569	7,046
570	179,396
571	453,587
572	1,094
573	7,484
580	322,848
581	64,564
582	(268)
583	1,751
584	1,829
585	87
586	920,375
587	367,556
588	2,275,999
589	219
590	83,596
591	60
592	159,127
593	1,262,118
594	2,863
595	381
596	1,427
597	362,021
598	19,774
813	258,121
878	729,545
887	(7)
888	26
892	2
893	353,069
902	101,361

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

903	38,346,625
908	1,706,124
909	4,117
923	40,081,189
924	19,422
925	377
928	1,341,663
930.1	304,315
930.2	441,469
935	7
Total	<u>\$ 114,577,718</u>

Schedule Page: 429 Line No.: 5 Column: a

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.

Schedule Page: 429 Line No.: 6 Column: c

EBSC Centralized Support Services to DPL:

FERC	Amount
107	\$ 48,713,181
108	417,707
163	1,085,968
184	873,788
416	142,589
417.1	657
426.1	253,860
426.3	7
426.4	91,880
426.5	104,813
560	2,148,373
561.1	39
561.2	34,372
561.3	34
561.5	107
566	626,514
568	6
569	177
570	261,095
571	4,802
572	19
573	15,793
580	47,292
581	223,848
582	528
583	13,984
584	23,497
585	(17)
586	264,573
587	3,482
588	609,510
589	5,360
590	290
591	2,185
592	152,481
593	912,447
594	74,804
595	10,692
596	26,535
597	11,455
598	24,383
807	8,690
813	25,134
840	2,355

Name of Respondent	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 2020/Q4
Delmarva Power & Light Company			

FOOTNOTE DATA

841	45,693
843.1	2,463
843.3	23
843.4	308
843.5	990
843.6	187
843.7	79
843.9	4,753
850	5,999
851	69,296
856	12,090
857	3,163
859	5,076
860	742
861	641
863	6,791
865	2,959
870	33,331
871	14,248
874	200,950
875	9,230
878	63,996
879	3,240
880	1,205,960
881	25
885	10,143
887	31,735
888	54
889	2,813
892	38,814
893	22,275
894	21,206
902	108,408
903	8,897,078
908	335,109
912	11,804
921	239,730
923	35,286,087
924	771,647
925	3,189
928	13,162
930.1	101,708
930.2	18,347
935	5,304
Total	<u>\$ 104,830,135</u>

Schedule Page: 429 Line No.: 9 Column: c

ACE Materials provided to DPL:

FERC	Amount
107	\$ 19,784
108	521
154	364,395
570	647
596	770
Total	<u>\$ 386,117</u>

Schedule Page: 429 Line No.: 10 Column: c

ACE Mutual Assistance provided to DPL:

FERC	Amount
107	\$ 18,606
108	2,067
593	15,144
Total	<u>\$ 35,817</u>

Schedule Page: 429 Line No.: 11 Column: c

ACE Meter Transfers to DPL:

FERC	Amount
107	\$ 33,591
108	(722)
Total	

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

\$ 32,869

Schedule Page: 429 Line No.: 15 Column: c

Pepco Materials provided to DPL:

FERC	Amount
107	\$ 287,401
108	4,765
154	38,919
921	4,600
Various-overhead acct.	51
Total	<u>\$ 335,736</u>

Schedule Page: 429 Line No.: 16 Column: c

Pepco Mutual Assistanace provided to DPL:

FERC	Amount
107	\$ 91,552
108	10,172
593	78,747
Total	<u>\$ 180,471</u>

Schedule Page: 429 Line No.: 25 Column: c

DPL Building Services (use of building space) provided to ACE:

FERC	Amount
456	\$ 18,048
495	3,150
Total	<u>\$ 21,198</u>

Schedule Page: 429 Line No.: 40 Column: c

DPL Building Services (use of building space) provided to Pepco:

FERC	Amount
456	\$ 4,571
495	798
Total	<u>\$ 5,369</u>

Schedule Page: 429.1 Line No.: 5 Column: c

PECO Information Technology Services provided to DPL:

FERC	Amount
107	\$ 5,814
921	25,632
Total	<u>\$ 31,446</u>

Schedule Page: 429.1 Line No.: 10 Column: c

BGE Information Technology Services provided to DPL:

FERC	Amount
107	\$ 90,699
921	60,024
Total	<u>\$ 150,723</u>

Schedule Page: 429.1 Line No.: 11 Column: c

BGE Mutual Assistance provided to DPL:

FERC	Amount
107	\$ 7,455
108	828
593	13,806
Total	<u>\$ 22,089</u>

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

Schedule Page: 429.1 Line No.: 15 Column: c

ComEd Mutual Assistance provided to DPL:

FERC	Amount
107	\$ 757,084
108	84,121
593	1,501,384
Total	<u>\$ 2,342,589</u>

Schedule Page: 429.1 Line No.: 16 Column: c

ComEd Information Technology Services provided to DPL:

FERC	Amount
107	\$ 80,787
921	30,300
Total	<u>\$ 111,087</u>

Schedule Page: 429.1 Line No.: 27 Column: c

DPL Building Services (use of building space) provided to EBSC:

FERC	Amount
454	\$ 325,867
456	448,182
495	78,224
Total	<u>\$ 852,273</u>

Schedule Page: 429.1 Line No.: 32 Column: c

DPL Building Services (use of building space) provided to PHISCO:

FERC	Amount
456	\$ 2,337,159
495	407,918
Total	<u>\$ 2,745,077</u>

Schedule Page: 429.1 Line No.: 37 Column: c

DPL Fiber Connection Services to CSM:

FERC	Amount
107	75,652
421	12,202
Total	<u>87,854</u>

Schedule Page: 429.2 Line No.: 3 Column: c

CPSG Mechanical and Electrical Industrial Services to DPL:

FERC	Amount
107	\$ 480,160
108	73,287
923	54,927
Total	<u>\$ 608,374</u>

Schedule Page: 429.2 Line No.: 6 Column: c

EC Inspection Services provided to DPL:

FERC	Amount
569	\$ 11,759
583	50,481
Total	<u>\$ 62,240</u>

Schedule Page: 429.2 Line No.: 7 Column: c

EC Mutual Assistance provided to DPL:

Name of Respondent Delmarva Power & Light Company	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 2020/Q4
FOOTNOTE DATA			

FERC	Amount
107	\$ 936
108	104
Total	<u>\$ 1,040</u>

<u>Schedule</u>	<u>Page No.</u>
Accrued and prepaid taxes	262-263
Accumulated Deferred Income Taxes	234
	272-277
Accumulated provisions for depreciation of	
common utility plant	356
utility plant	219
utility plant (summary)	200-201
Advances	
from associated companies	256-257
Allowances	228-229
Amortization	
miscellaneous	340
of nuclear fuel	202-203
Appropriations of Retained Earnings	118-119
Associated Companies	
advances from	256-257
corporations controlled by respondent	103
control over respondent	102
interest on debt to	256-257
Attestation	i
Balance sheet	
comparative	110-113
notes to	122-123
Bonds	256-257
Capital Stock	251
expense	254
premiums	252
reacquired	251
subscribed	252
Cash flows, statement of	120-121
Changes	
important during year	108-109
Construction	
work in progress - common utility plant	356
work in progress - electric	216
work in progress - other utility departments	200-201
Control	
corporations controlled by respondent	103
over respondent	102
Corporation	
controlled by	103
incorporated	101
CPA, background information on	101
CPA Certification, this report form	i-ii

Schedule

Page No.

Deferred

- credits, other 269
- debits, miscellaneous 233
- income taxes accumulated - accelerated
- amortization property 272-273
- income taxes accumulated - other property 274-275
- income taxes accumulated - other 276-277
- income taxes accumulated - pollution control facilities 234

Definitions, this report form iii

Depreciation and amortization

- of common utility plant 356
- of electric plant 219
- 336-337

Directors 105

Discount - premium on long-term debt 256-257

Distribution of salaries and wages 354-355

Dividend appropriations 118-119

Earnings, Retained 118-119

Electric energy account 401

Expenses

- electric operation and maintenance 320-323
- electric operation and maintenance, summary 323
- unamortized debt 256

Extraordinary property losses 230

Filing requirements, this report form

General information 101

Instructions for filing the FERC Form 1 i-iv

Generating plant statistics

- hydroelectric (large) 406-407
- pumped storage (large) 408-409
- small plants 410-411
- steam-electric (large) 402-403

Hydro-electric generating plant statistics 406-407

Identification 101

Important changes during year 108-109

Income

- statement of, by departments 114-117
- statement of, for the year (see also revenues) 114-117
- deductions, miscellaneous amortization 340
- deductions, other income deduction 340
- deductions, other interest charges 340

Incorporation information 101

Schedule

Page No.

Interest	
charges, paid on long-term debt, advances, etc	256-257
Investments	
nonutility property	221
subsidiary companies	224-225
Investment tax credits, accumulated deferred	266-267
Law, excerpts applicable to this report form	iv
List of schedules, this report form	2-4
Long-term debt	256-257
Losses-Extraordinary property	230
Materials and supplies	227
Miscellaneous general expenses	335
Notes	
to balance sheet	122-123
to statement of changes in financial position	122-123
to statement of income	122-123
to statement of retained earnings	122-123
Nonutility property	221
Nuclear fuel materials	202-203
Nuclear generating plant, statistics	402-403
Officers and officers' salaries	104
Operating	
expenses-electric	320-323
expenses-electric (summary)	323
Other	
paid-in capital	253
donations received from stockholders	253
gains on resale or cancellation of reacquired capital stock	253
miscellaneous paid-in capital	253
reduction in par or stated value of capital stock	253
regulatory assets	232
regulatory liabilities	278
Peaks, monthly, and output	401
Plant, Common utility	
accumulated provision for depreciation	356
acquisition adjustments	356
allocated to utility departments	356
completed construction not classified	356
construction work in progress	356
expenses	356
held for future use	356
in service	356
leased to others	356
Plant data	336-337
	401-429

Schedule

Page No.

Plant - electric

- accumulated provision for depreciation 219
- construction work in progress 216
- held for future use 214
- in service 204-207
- leased to others 213

Plant - utility and accumulated provisions for depreciation

- amortization and depletion (summary) 201

Pollution control facilities, accumulated deferred

- income taxes 234

Power Exchanges 326-327

Premium and discount on long-term debt 256

Premium on capital stock 251

Prepaid taxes 262-263

Property - losses, extraordinary 230

Pumped storage generating plant statistics 408-409

Purchased power (including power exchanges) 326-327

Reacquired capital stock 250

Reacquired long-term debt 256-257

Receivers' certificates 256-257

Reconciliation of reported net income with taxable income

- from Federal income taxes 261

Regulatory commission expenses deferred 233

Regulatory commission expenses for year 350-351

Research, development and demonstration activities 352-353

Retained Earnings

- amortization reserve Federal 119
- appropriated 118-119
- statement of, for the year 118-119
- unappropriated 118-119

Revenues - electric operating 300-301

Salaries and wages

- directors fees 105
- distribution of 354-355
- officers' 104

Sales of electricity by rate schedules 304

Sales - for resale 310-311

Salvage - nuclear fuel 202-203

Schedules, this report form 2-4

Securities

- exchange registration 250-251

Statement of Cash Flows 120-121

Statement of income for the year 114-117

Statement of retained earnings for the year 118-119

Steam-electric generating plant statistics 402-403

Substations 426

Supplies - materials and 227

Schedule

Page No.

Taxes

accrued and prepaid	262-263
charged during year	262-263
on income, deferred and accumulated	234
	272-277
reconciliation of net income with taxable income for	261

Transformers, line - electric	429
-------------------------------------	-----

Transmission

lines added during year	424-425
lines statistics	422-423
of electricity for others	328-330
of electricity by others	332

Unamortized

debt discount	256-257
debt expense	256-257
premium on debt	256-257

Unrecovered Plant and Regulatory Study Costs	230
--	-----

Document Content(s)

Form120201200043.PDF.....1

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	289,076,256	276,234,797
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	104,791,351	109,566,340
5	Large (or Ind.) (See Instr. 4)	9,395,892	9,221,225
6	(444) Public Street and Highway Lighting	4,160,994	4,297,297
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	407,424,493	399,319,659
11	(447) Sales for Resale	46,438	3,238
12	TOTAL Sales of Electricity	407,470,931	399,322,897
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	407,470,931	399,322,897
15	Other Operating Revenues		
16	(450) Forfeited Discounts	244,291	725,895
17	(451) Miscellaneous Service Revenues	62,188	227,896
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,560,081	1,514,770
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	7,069,792	7,327,220
22	(456.1) Revenues from Transmission of Electricity of Others	616,553	639,597
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	9,552,905	10,435,378
27	TOTAL Electric Operating Revenues	417,023,836	409,758,275

Name of Respondent
Delmarva Power & Light Company - Maryland

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
/ /

Year/Period of Report
End of 2020/Q4

ELECTRIC OPERATING REVENUES (Account 400)

- 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 pages 108-109, 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.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
2,092,433	2,137,594	180,786	179,408	2
				3
1,533,628	1,658,493	27,028	26,867	4
365,734	369,282	528	513	5
10,841	11,560	263	266	6
				7
				8
				9
4,002,636	4,176,929	208,605	207,054	10
966	66			11
4,003,602	4,176,995	208,605	207,054	12
				13
4,003,602	4,176,995	208,605	207,054	14

Line 12, column (b) includes \$ 2,977,559 of unbilled revenues.
 Line 12, column (d) includes 16,865 MWH relating to unbilled revenues

Name of Respondent Delmarva Power & Light Company - Maryland	This Report is: (1) __ An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2020/Q4
FOOTNOTE DATA			

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

Amounts over \$250,000:
 \$ 1,796,599 RPM Auction
 3,578,180 MD Bill Stabilization Adjustment
 (1,185,898) MD Calendar Revenue Normalization
 426,133 MD Intracompany Power Sales
 898,656 Net Metering

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

Amounts over \$250,000:
 \$ 4,916,066 RPM Auction
 1,528,680 MD Bill Stabilization Adjustment
 (946,033) MD Calendar Revenue Normalization
 746,122 MD Intercompany Revenue
 478,965 MD Intracompany Power Sales
 543,555 Net Metering

DELMARVA POWER & LIGHT COMPANY
MARYLAND PROPERTY TAXES PAID
12/31/2020

<u>Location</u>	<u>Rounded 2020 Taxes Paid</u>
Caroline County	912
Cecil County	29
City of Cambridge	-
City of Crisfield	-
City of Fruitland	-
City of Salisbury	1,403,757
Delmar	24,009
Dorchester County	17,594
Eldorado	-
Galena	-
Harford County	2,167
Hebron	-
Hillsboro	-
Hurlock	-
Kent County	1,708,559
Mardela Springs	-
Pocomoke City	-
Preston	-
Queen Anne's County	12,964
Ridgely	-
Secretary	-
Sharptown	-
Snow Hill	-
Somerset County	1,002
St. Michaels	-
Sudlersville	1,341
Talbot County	39
Town of Betterton	-
Town of Brookview	-
Town of Cecilton	-
Town of Centreville	-
Town of Charlestown	-
Town of Chesapeake City	-
Town of Chestertown	-
Town of Church Creek	-
Town of Church Hill	-
Town of Denton	-
Town of Elkton	144,542
Town of Federalsburg	-
Town of Goldsboro	-
Town of Greensboro	-
Town of Henderson	562
Town of Marydel	-
Town of Millington	-
Town of North East	-
Town of Ocean City	-
Town of Perryville	-
Town of Pittsville	-
Town of Port Deposit	-
Town of Princess Anne	-
Town of Queenstown	-
Town of Rising Sun	12,730
Town of Templeville	-
Town of Trappe	-
Town of Vienna	-
Town of Willards	-
Wicomico County	30,315
Worcester County	4,193
MD Other Property	300
Total	3,365,015

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, 2021

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
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
001-01839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (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 (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 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702 (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.

Company Name	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company	Emerging Growth Company
Exelon Corporation	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Exelon Generation Company, LLC	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Commonwealth Edison Company	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
PECO Energy Company	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Baltimore Gas and Electric Company	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Pepco Holdings LLC	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Potomac Electric Power Company	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Delmarva Power & Light Company	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
Atlantic City Electric Company	<input type="checkbox"/>	<input type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>	<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, 2021 was:

Exelon Corporation Common Stock, without par value	977,175,235
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, \$12.50 par value	127,021,380
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

TABLE OF CONTENTS

	<u>Page No.</u>
<u>GLOSSARY OF TERMS AND ABBREVIATIONS</u>	4
<u>FILING FORMAT</u>	8
<u>CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION</u>	8
<u>WHERE TO FIND MORE INFORMATION</u>	8
PART I. FINANCIAL INFORMATION	9
ITEM 1. FINANCIAL STATEMENTS	9
<u>Exelon Corporation</u>	
<u>Consolidated Statements of Operations and Comprehensive Income</u>	10
<u>Consolidated Statements of Cash Flows</u>	11
<u>Consolidated Balance Sheets</u>	12
<u>Consolidated Statements of Changes in Shareholders' Equity</u>	14
<u>Exelon Generation Company, LLC</u>	
<u>Consolidated Statements of Operations and Comprehensive Income</u>	15
<u>Consolidated Statements of Cash Flows</u>	16
<u>Consolidated Balance Sheets</u>	17
<u>Consolidated Statements of Changes in Equity</u>	19
<u>Commonwealth Edison Company</u>	
<u>Consolidated Statements of Operations and Comprehensive Income</u>	20
<u>Consolidated Statements of Cash Flows</u>	21
<u>Consolidated Balance Sheets</u>	22
<u>Consolidated Statements of Changes in Shareholders' Equity</u>	24
<u>PECO Energy Company</u>	
<u>Consolidated Statements of Operations and Comprehensive Income</u>	25
<u>Consolidated Statements of Cash Flows</u>	26
<u>Consolidated Balance Sheets</u>	27
<u>Consolidated Statements of Changes in Shareholder's Equity</u>	29
<u>Baltimore Gas and Electric Company</u>	
<u>Statements of Operations and Comprehensive Income</u>	30
<u>Statements of Cash Flows</u>	31
<u>Balance Sheets</u>	32
<u>Statements of Changes in Shareholder's Equity</u>	34
<u>Pepco Holdings LLC</u>	
<u>Consolidated Statements of Operations and Comprehensive Income</u>	35
<u>Consolidated Statements of Cash Flows</u>	36
<u>Consolidated Balance Sheets</u>	37
<u>Consolidated Statements of Changes in Equity</u>	39

	Page No.
Potomac Electric Power Company	
<u>Statements of Operations and Comprehensive Income</u>	<u>40</u>
<u>Statements of Cash Flows</u>	<u>41</u>
<u>Balance Sheets</u>	<u>42</u>
<u>Statements of Changes in Shareholder's Equity</u>	<u>44</u>
Delmarva Power & Light Company	
<u>Statements of Operations and Comprehensive Income</u>	<u>45</u>
<u>Statements of Cash Flows</u>	<u>46</u>
<u>Balance Sheets</u>	<u>47</u>
<u>Statements of Changes in Shareholder's Equity</u>	<u>49</u>
Atlantic City Electric Company	
<u>Consolidated Statements of Operations and Comprehensive Income</u>	<u>50</u>
<u>Consolidated Statements of Cash Flows</u>	<u>51</u>
<u>Consolidated Balance Sheets</u>	<u>52</u>
<u>Consolidated Statements of Changes in Shareholder's Equity</u>	<u>54</u>
Combined Notes to Consolidated Financial Statements	
<u>1. Significant Accounting Policies</u>	<u>55</u>
<u>2. Mergers, Acquisitions and Dispositions</u>	<u>56</u>
<u>3. Regulatory Matters</u>	<u>57</u>
<u>4. Revenue from Contracts with Customers</u>	<u>62</u>
<u>5. Segment Information</u>	<u>64</u>
<u>6. Accounts Receivable</u>	<u>72</u>
<u>7. Early Plant Retirements</u>	<u>75</u>
<u>8. Nuclear Decommissioning</u>	<u>77</u>
<u>9. Income Taxes</u>	<u>79</u>
<u>10. Retirement Benefits</u>	<u>80</u>
<u>11. Derivative Financial Instruments</u>	<u>82</u>
<u>12. Debt and Credit Agreements</u>	<u>87</u>
<u>13. Fair Value of Financial Assets and Liabilities</u>	<u>90</u>
<u>14. Commitments and Contingencies</u>	<u>100</u>
<u>15. Changes in Accumulated Other Comprehensive Income</u>	<u>107</u>
<u>16. Variable Interest Entities</u>	<u>108</u>
<u>17. Supplemental Financial Information</u>	<u>112</u>
<u>18. Related Party Transactions</u>	<u>117</u>
<u>19. Planned Separation</u>	<u>120</u>

	<u>Page No.</u>
<u>ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS</u>	<u>121</u>
<u>Exelon Corporation</u>	<u>121</u>
<u>Executive Overview</u>	<u>121</u>
<u>Financial Results of Operations</u>	<u>121</u>
<u>Significant 2021 Transactions and Developments</u>	<u>124</u>
<u>Other Key Business Drivers and Management Strategies</u>	<u>126</u>
<u>Critical Accounting Policies and Estimates</u>	<u>127</u>
<u>Results of Operations By Registrant</u>	<u>127</u>
<u>Exelon Generation Company, LLC</u>	<u>128</u>
<u>Commonwealth Edison Company</u>	<u>134</u>
<u>PECO Energy Company</u>	<u>137</u>
<u>Baltimore Gas and Electric Company</u>	<u>141</u>
<u>Pepco Holdings LLC</u>	<u>144</u>
<u>Potomac Electric Power Company</u>	<u>145</u>
<u>Delmarva Power & Light Company</u>	<u>147</u>
<u>Atlantic City Electric Company</u>	<u>151</u>
<u>Liquidity and Capital Resources</u>	<u>154</u>
<u>Contractual Obligations and Off-Balance Sheet Arrangements</u>	<u>161</u>
<u>ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK</u>	<u>162</u>
<u>ITEM 4. CONTROLS AND PROCEDURES</u>	<u>166</u>
<u>PART II. OTHER INFORMATION</u>	<u>167</u>
<u>ITEM 1. LEGAL PROCEEDINGS</u>	<u>167</u>
<u>ITEM 1A. RISK FACTORS</u>	<u>167</u>
<u>ITEM 4. MINE SAFETY DISCLOSURES</u>	<u>167</u>
<u>ITEM 5. OTHER INFORMATION</u>	<u>167</u>
<u>ITEM 6. EXHIBITS</u>	<u>168</u>
<u>SIGNATURES</u>	<u>171</u>
<u>Exelon Corporation</u>	<u>171</u>
<u>Exelon Generation Company, LLC</u>	<u>172</u>
<u>Commonwealth Edison Company</u>	<u>173</u>
<u>PECO Energy Company</u>	<u>174</u>
<u>Baltimore Gas and Electric Company</u>	<u>175</u>
<u>Pepco Holdings LLC</u>	<u>176</u>
<u>Potomac Electric Power Company</u>	<u>177</u>
<u>Delmarva Power & Light Company</u>	<u>178</u>
<u>Atlantic City Electric Company</u>	<u>179</u>

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

<i>Exelon</i>	Exelon Corporation
<i>Generation</i>	Exelon Generation Company, LLC
<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, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, collectively
<i>Utility Registrants</i>	ComEd, PECO, BGE, Pepco, DPL, and ACE, collectively
<i>ACE Funding or ATF</i>	Atlantic City Electric Transition Funding LLC
<i>Antelope Valley</i>	Antelope Valley Solar Ranch One
<i>BSC</i>	Exelon Business Services Company, LLC
<i>CENG</i>	Constellation Energy Nuclear Group, LLC
<i>Constellation</i>	Constellation Energy Group, Inc.
<i>EGR IV</i>	ExGen Renewables IV, LLC
<i>EGRP</i>	ExGen Renewables Partners, LLC
<i>Exelon Corporate</i>	Exelon in its corporate capacity as a holding company
<i>FitzPatrick</i>	James A. FitzPatrick nuclear generating station
<i>NER</i>	NewEnergy Receivables LLC
<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>Pepco Energy Services</i>	Pepco Energy Services, Inc. and its subsidiaries
<i>PHI Corporate</i>	PHI in its corporate capacity as a holding company
<i>PHISCO</i>	PHI Service Company
<i>RPG</i>	Renewable Power Generation
<i>SolGen</i>	SolGen, LLC
<i>TMI</i>	Three Mile Island nuclear facility

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

<i>Note - of the 2020 Form 10-K</i>	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2020 Annual Report on Form 10-K
<i>AEC</i>	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
<i>AESO</i>	Alberta Electric Systems Operator
<i>AFUDC</i>	Allowance for Funds Used During Construction
<i>AMI</i>	Advanced Metering Infrastructure
<i>AOCI</i>	Accumulated Other Comprehensive Income (Loss)
<i>ARC</i>	Asset Retirement Cost
<i>ARO</i>	Asset Retirement Obligation
<i>BGS</i>	Basic Generation Service
<i>CBA</i>	Collective Bargaining Agreement
<i>CERCLA</i>	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
<i>CES</i>	Clean Energy Standard
<i>Clean Water Act</i>	Federal Water Pollution Control Amendments of 1972, as amended
<i>CODM</i>	Chief operating decision maker(s)
<i>D.C. Circuit Court</i>	United States Court of Appeals for the District of Columbia Circuit
<i>DC PLUG</i>	District of Columbia Power Line Undergrounding Initiative
<i>DCPSC</i>	Public Service Commission of the District of Columbia
<i>DOE</i>	United States Department of Energy
<i>DOEE</i>	District of Columbia Department of Energy & Environment
<i>DOJ</i>	United States Department of Justice
<i>DPP</i>	Deferred Purchase Price
<i>DPSC</i>	Delaware Public Service Commission
<i>EDF</i>	Electricite de France SA and its subsidiaries
<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>FASB</i>	Financial Accounting Standards Board
<i>FEJA</i>	Illinois Public Act 99-0906 or Future Energy Jobs Act
<i>FERC</i>	Federal Energy Regulatory Commission
<i>FRCC</i>	Florida Reliability Coordinating Council
<i>FRR</i>	Fixed Resource Requirement
<i>GAAP</i>	Generally Accepted Accounting Principles in the United States
<i>GCR</i>	Gas Cost Rate
<i>GSA</i>	Generation Supply Adjustment
<i>IBEW</i>	International Brotherhood of Electrical Workers
<i>ICC</i>	Illinois Commerce Commission
<i>ICE</i>	Intercontinental Exchange
<i>IPA</i>	Illinois Power Agency
<i>IRC</i>	Internal Revenue Code
<i>IRS</i>	Internal Revenue Service
<i>ISO</i>	Independent System Operator
<i>ISO-NE</i>	Independent System Operator New England Inc.

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

<i>LIBOR</i>	London Interbank Offered Rate
<i>MDE</i>	Maryland Department of the Environment
<i>MDPSC</i>	Maryland Public Service Commission
<i>MGP</i>	Manufactured Gas Plant
<i>MISO</i>	Midcontinent Independent System Operator, Inc.
<i>mmcf</i>	Million Cubic Feet
<i>MOPR</i>	Minimum Offer Price Rule
<i>MPSC</i>	Missouri Public Service Commission
<i>MW</i>	Megawatt
<i>MWh</i>	Megawatt hour
<i>NAV</i>	Net Asset Value
<i>N/A</i>	Not applicable
<i>NDT</i>	Nuclear Decommissioning Trust
<i>NERC</i>	North American Electric Reliability Corporation
<i>NGX</i>	Natural Gas Exchange
<i>NJBPU</i>	New Jersey Board of Public Utilities
<i>Non-Regulatory Agreement Units</i>	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
<i>NOSA</i>	Nuclear Operating Services Agreement
<i>NPNS</i>	Normal Purchase Normal Sale scope exception
<i>NRC</i>	Nuclear Regulatory Commission
<i>NYISO</i>	New York Independent System Operator Inc.
<i>NYMEX</i>	New York Mercantile Exchange
<i>NYPSC</i>	New York Public Service Commission
<i>OCI</i>	Other Comprehensive Income
<i>OIESO</i>	Ontario Independent Electricity System Operator
<i>OPEB</i>	Other Postretirement Employee Benefits
<i>PAPUC</i>	Pennsylvania Public Utility Commission
<i>PGC</i>	Purchased Gas Cost Clause
<i>PG&E</i>	Pacific Gas and Electric Company
<i>PJM</i>	PJM Interconnection, LLC
<i>POLR</i>	Provider of Last Resort
<i>PPA</i>	Power Purchase Agreement
<i>PPE</i>	Property, plant, and equipment
<i>Price-Anderson Act</i>	Price-Anderson Nuclear Industries Indemnity Act of 1957
<i>PRP</i>	Potentially Responsible Parties
<i>PSDAR</i>	Post-Shutdown Decommissioning Activities Report
<i>PSEG</i>	Public Service Enterprise Group Incorporated
<i>PUCT</i>	Public Utility Commission of Texas
<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>RMC</i>	Risk Management Committee

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

<i>RNF</i>	Revenues Net of Purchased Power and Fuel Expense
<i>ROE</i>	Return on equity
<i>ROU</i>	Right-of-use
<i>RTO</i>	Regional Transmission Organization
<i>S&P</i>	Standard & Poor's Ratings Services
<i>SEC</i>	United States Securities and Exchange Commission
<i>SERC</i>	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
<i>SNF</i>	Spent Nuclear Fuel
<i>SOS</i>	Standard Offer Service
<i>STRIDE</i>	Maryland Strategic Infrastructure Development and Enhancement Program
<i>Transition Bonds</i>	Transition Bonds issued by ACE Funding
<i>VIE</i>	Variable Interest Entity
<i>WECC</i>	Western Electric Coordinating Council
<i>ZEC</i>	Zero Emission Credit, or Zero Emission Certificate
<i>ZES</i>	Zero Emission Standard

FILING FORMAT

This combined Form 10-Q is being filed separately by Exelon Corporation, Exelon Generation Company, LLC, 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 including, among others, those related to the timing, manner, tax-free nature, and expected benefits associated with the potential separation of Exelon's competitive power generation and customer-facing energy business from its six regulated electric and gas utilities. Words such as "could," "may," "expects," "anticipates," "will," "targets," "goals," "projects," "intends," "plans," "believes," "seeks," "estimates," "predicts," 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 Registrants' combined 2020 Annual Report on Form 10-K in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 19, 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 14, 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,	
	2021	2020
Operating revenues		
Competitive businesses revenues	\$ 5,265	\$ 4,404
Rate-regulated utility revenues	4,496	4,276
Revenues from alternative revenue programs	129	67
Total operating revenues	9,890	8,747
Operating expenses		
Competitive businesses purchased power and fuel	4,610	2,710
Rate-regulated utility purchased power and fuel	1,358	1,157
Operating and maintenance	1,979	2,204
Depreciation and amortization	1,697	1,021
Taxes other than income taxes	438	437
Total operating expenses	10,082	7,529
Gain on sales of assets and businesses	71	2
Operating (loss) income	(121)	1,220
Other income and (deductions)		
Interest expense, net	(380)	(404)
Interest expense to affiliates	(6)	(6)
Other, net	225	(725)
Total other income and (deductions)	(161)	(1,135)
(Loss) income before income taxes	(282)	85
Income taxes	(19)	(294)
Equity in losses of unconsolidated affiliates	(1)	(3)
Net (loss) income	(264)	376
Net income (loss) attributable to noncontrolling interests	25	(206)
Net (loss) income attributable to common shareholders	\$ (289)	\$ 582
Comprehensive income, net of income taxes		
Net (loss) income	\$ (264)	\$ 376
Other comprehensive income (loss), net of income taxes		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	(1)	(10)
Actuarial loss reclassified to periodic benefit cost	56	47
Pension and non-pension postretirement benefit plan valuation adjustment	(2)	(7)
Unrealized loss on cash flow hedges	—	(1)
Unrealized gain (loss) on foreign currency translation	1	(8)
Other comprehensive income	54	21
Comprehensive (loss) income	(210)	397
Comprehensive income (loss) attributable to noncontrolling interests	25	(206)
Comprehensive (loss) income attributable to common shareholders	\$ (235)	\$ 603
Average shares of common stock outstanding:		
Basic	977	975
Assumed exercise and/or distributions of stock-based awards	—	1
Diluted ^(a)	977	976
(Losses) earnings per average common share		
Basic	\$ (0.30)	\$ 0.60
Diluted	\$ (0.30)	\$ 0.60

(a) The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was less than 1 million for the three months ended March 31, 2021 and March 31, 2020.

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,	
	2021	2020
Cash flows from operating activities		
Net (loss) income	\$ (264)	\$ 376
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	2,104	1,378
Asset impairments	1	8
Gain on sales of assets and businesses	(71)	—
Deferred income taxes and amortization of investment tax credits	(142)	(245)
Net fair value changes related to derivatives	(178)	(132)
Net realized and unrealized (gains) losses on NDT funds	(118)	651
Unrealized loss on equity investments	23	—
Other non-cash operating activities	(170)	273
Changes in assets and liabilities:		
Accounts receivable	(372)	800
Inventories	77	81
Accounts payable and accrued expenses	(176)	(976)
Option premiums received (paid), net	16	(38)
Collateral received (posted), net	273	(21)
Income taxes	113	(56)
Pension and non-pension postretirement benefit contributions	(537)	(531)
Other assets and liabilities	(1,840)	(488)
Net cash flows (used in) provided by operating activities	(1,261)	1,080
Cash flows from investing activities		
Capital expenditures	(2,140)	(2,016)
Proceeds from NDT fund sales	2,908	1,183
Investment in NDT funds	(2,939)	(1,234)
Collection of DPP	1,574	—
Proceeds from sales of assets and businesses	680	—
Other investing activities	12	(8)
Net cash flows provided by (used in) investing activities	95	(2,075)
Cash flows from financing activities		
Changes in short-term borrowings	597	109
Proceeds from short-term borrowings with maturities greater than 90 days	500	500
Issuance of long-term debt	1,705	2,652
Retirement of long-term debt	(79)	(1,032)
Dividends paid on common stock	(374)	(373)
Proceeds from employee stock plans	31	30
Other financing activities	(46)	(21)
Net cash flows provided by financing activities	2,334	1,865
Increase in cash, restricted cash, and cash equivalents	1,168	870
Cash, restricted cash, and cash equivalents at beginning of period	1,166	1,122
Cash, restricted cash, and cash equivalents at end of period	\$ 2,334	\$ 1,992
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (324)	\$ (180)
Increase in DPP	1,339	—

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	\$ 1,908	\$ 663
Restricted cash and cash equivalents	374	438
Accounts receivable		
Customer accounts receivable	4,017	3,597
Customer allowance for credit losses	(442)	(366)
Customer accounts receivable, net	3,575	3,231
Other accounts receivable	1,320	1,469
Other allowance for credit losses	(79)	(71)
Other accounts receivable, net	1,241	1,398
Mark-to-market derivative assets	568	644
Unamortized energy contract assets	38	38
Inventories, net		
Fossil fuel and emission allowances	205	297
Materials and supplies	1,427	1,425
Regulatory assets	1,269	1,228
Renewable energy credits	694	633
Assets held for sale	11	958
Other	1,687	1,609
Total current assets	12,997	12,562
Property, plant, and equipment (net of accumulated depreciation and amortization of \$28,121 and \$26,727 as of March 31, 2021 and December 31, 2020, respectively)	82,588	82,584
Deferred debits and other assets		
Regulatory assets	8,810	8,759
Nuclear decommissioning trust funds	14,688	14,464
Investments	431	440
Goodwill	6,677	6,677
Mark-to-market derivative assets	491	555
Unamortized energy contract assets	285	294
Other	3,033	2,982
Total deferred debits and other assets	34,415	34,171
Total assets^(a)	\$ 130,000	\$ 129,317

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	\$ 3,128	\$ 2,031
Long-term debt due within one year	2,281	1,819
Accounts payable	3,430	3,562
Accrued expenses	1,729	2,078
Payables to affiliates	5	5
Regulatory liabilities	663	581
Mark-to-market derivative liabilities	422	295
Unamortized energy contract liabilities	98	100
Renewable energy credit obligation	645	661
Liabilities held for sale	3	375
Other	1,176	1,264
Total current liabilities	13,580	12,771
Long-term debt	36,248	35,093
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,129	13,035
Asset retirement obligations	12,405	12,300
Pension obligations	3,951	4,503
Non-pension postretirement benefit obligations	1,988	2,011
Spent nuclear fuel obligation	1,208	1,208
Regulatory liabilities	9,130	9,485
Mark-to-market derivative liabilities	453	473
Unamortized energy contract liabilities	217	238
Other	2,988	2,942
Total deferred credits and other liabilities	45,469	46,195
Total liabilities ^(a)	95,687	94,449
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 977 shares and 976 shares outstanding at March 31, 2021 and December 31, 2020, respectively)	19,412	19,373
Treasury stock, at cost (2 shares at March 31, 2021 and December 31, 2020)	(123)	(123)
Retained earnings	16,072	16,735
Accumulated other comprehensive loss, net	(3,346)	(3,400)
Total shareholders' equity	32,015	32,585
Noncontrolling interests	2,298	2,283
Total equity	34,313	34,868
Total liabilities and shareholders' equity	\$ 130,000	\$ 129,317

(a) Exelon's consolidated assets include \$9,985 million and \$10,200 million at March 31, 2021 and December 31, 2020, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include \$3,578 million and \$3,598 million at March 31, 2021 and December 31, 2020, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 16 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

Three Months Ended March 31, 2021							
(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2020	977,466	\$ 19,373	\$ (123)	\$ 16,735	\$ (3,400)	\$ 2,283	\$ 34,868
Net (loss) income	—	—	—	(289)	—	25	(264)
Long-term incentive plan activity	640	5	—	—	—	—	5
Employee stock purchase plan issuances	902	34	—	—	—	—	34
Changes in equity of noncontrolling interests	—	—	—	—	—	(10)	(10)
Common stock dividends (\$0.38/common share)	—	—	—	(374)	—	—	(374)
Other comprehensive income, net of income taxes	—	—	—	—	54	—	54
Balance, March 31, 2021	<u>979,008</u>	<u>\$ 19,412</u>	<u>\$ (123)</u>	<u>\$ 16,072</u>	<u>\$ (3,346)</u>	<u>\$ 2,298</u>	<u>\$ 34,313</u>

Three Months Ended March 31, 2020							
(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2019	974,416	\$ 19,274	\$ (123)	\$ 16,267	\$ (3,194)	\$ 2,349	\$ 34,573
Net income (loss)	—	—	—	582	—	(206)	376
Long-term incentive plan activity	1,354	(4)	—	—	—	—	(4)
Employee stock purchase plan issuances	470	31	—	—	—	—	31
Changes in equity of noncontrolling interests	—	—	—	—	—	(9)	(9)
Sale of noncontrolling interests	—	2	—	—	—	—	2
Common stock dividends (\$0.38/common share)	—	—	—	(374)	—	—	(374)
Other comprehensive income, net of income taxes	—	—	—	—	21	—	21
Balance, March 31, 2020	<u>976,240</u>	<u>\$ 19,303</u>	<u>\$ (123)</u>	<u>\$ 16,475</u>	<u>\$ (3,173)</u>	<u>\$ 2,134</u>	<u>\$ 34,616</u>

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2021	2020
Operating revenues		
Operating revenues	\$ 5,264	\$ 4,403
Operating revenues from affiliates	295	330
Total operating revenues	<u>5,559</u>	<u>4,733</u>
Operating expenses		
Purchased power and fuel	4,610	2,710
Purchased power and fuel from affiliates	—	(6)
Operating and maintenance	856	1,121
Operating and maintenance from affiliates	145	142
Depreciation and amortization	940	304
Taxes other than income taxes	121	129
Total operating expenses	<u>6,672</u>	<u>4,400</u>
Gain on sales of assets and businesses	71	—
Operating (loss) income	<u>(1,042)</u>	<u>333</u>
Other income and (deductions)		
Interest expense, net	(68)	(100)
Interest expense to affiliates	(4)	(9)
Other, net	167	(771)
Total other income and (deductions)	<u>95</u>	<u>(880)</u>
Loss before income taxes	(947)	(547)
Income taxes	(179)	(389)
Equity in losses of unconsolidated affiliates	(1)	(3)
Net loss	<u>(769)</u>	<u>(161)</u>
Net income (loss) attributable to noncontrolling interests	24	(206)
Net (loss) income attributable to membership interest	<u>\$ (793)</u>	<u>\$ 45</u>
Comprehensive income, net of income taxes		
Net loss	\$ (769)	\$ (161)
Other comprehensive income (loss), net of income taxes		
Unrealized loss on cash flow hedges	—	(1)
Unrealized gain (loss) on foreign currency translation	1	(8)
Other comprehensive income (loss), net of income taxes	<u>1</u>	<u>(9)</u>
Comprehensive loss	<u>(768)</u>	<u>(170)</u>
Comprehensive income (loss) attributable to noncontrolling interests	24	(206)
Comprehensive (loss) income attributable to membership interest	<u>\$ (792)</u>	<u>\$ 36</u>

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2021	2020
Cash flows from operating activities		
Net loss	\$ (769)	\$ (161)
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	1,346	661
Asset impairments	1	8
Gain on sales of assets and businesses	(71)	—
Deferred income taxes and amortization of investment tax credits	(123)	(329)
Net fair value changes related to derivatives	(178)	(127)
Net realized and unrealized (gains) losses on NDT funds	(118)	651
Unrealized loss on equity investments	23	—
Other non-cash operating activities	(202)	205
Changes in assets and liabilities:		
Accounts receivable	(453)	787
Receivables from and payables to affiliates, net	59	34
Inventories	50	39
Accounts payable and accrued expenses	208	(614)
Option premiums received (paid), net	16	(38)
Collateral received (posted), net	270	(22)
Income taxes	(55)	(58)
Pension and non-pension postretirement benefit contributions	(205)	(232)
Other assets and liabilities	(1,411)	(184)
Net cash flows (used in) provided by operating activities	(1,612)	620
Cash flows from investing activities		
Capital expenditures	(382)	(558)
Proceeds from NDT fund sales	2,908	1,183
Investment in NDT funds	(2,939)	(1,234)
Collection of DPP	1,574	—
Proceeds from sales of assets and businesses	680	—
Changes in Exelon intercompany money pool	—	(254)
Other investing activities	(2)	(8)
Net cash flows provided by (used in) investing activities	1,839	(871)
Cash flows from financing activities		
Changes in short-term borrowings	997	275
Proceeds from short-term borrowings with maturities greater than 90 days	—	500
Issuance of long-term debt	1	1,502
Retirement of long-term debt	(35)	(1,028)
Changes in Exelon intercompany money pool	(285)	—
Distributions to member	(458)	(468)
Other financing activities	(12)	(8)
Net cash flows provided by financing activities	208	773
Increase in cash, restricted cash, and cash equivalents	435	522
Cash, restricted cash, and cash equivalents at beginning of period	327	449
Cash, restricted cash, and cash equivalents at end of period	\$ 762	\$ 971
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (37)	\$ (56)
Increase in DPP	1,339	—

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	\$ 721	\$ 226
Restricted cash and cash equivalents	41	89
Accounts receivable		
Customer accounts receivable	1,857	1,330
Customer allowance for credit losses	(65)	(32)
Customer accounts receivable, net	1,792	1,298
Other accounts receivable	348	352
Other accounts receivable, net	348	352
Mark-to-market derivative assets	569	644
Receivables from affiliates	106	153
Unamortized energy contract assets	38	38
Inventories, net		
Fossil fuel and emission allowances	175	233
Materials and supplies	973	978
Renewable energy credits	676	621
Assets held for sale	11	958
Other	1,290	1,357
Total current assets	6,740	6,947
Property, plant, and equipment (net of accumulated depreciation and amortization of \$14,355 and \$13,370 as of March 31, 2021 and December 31, 2020, respectively)	21,311	22,214
Deferred debits and other assets		
Nuclear decommissioning trust funds	14,688	14,464
Investments	178	184
Goodwill	47	47
Mark-to-market derivative assets	491	555
Prepaid pension asset	1,736	1,558
Unamortized energy contract assets	285	293
Deferred income taxes	15	6
Other	1,835	1,826
Total deferred debits and other assets	19,275	18,933
Total assets^(a)	\$ 47,326	\$ 48,094

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

<u>(In millions)</u>	<u>March 31, 2021</u>	<u>December 31, 2020</u>
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	\$ 1,837	\$ 840
Long-term debt due within one year	699	197
Accounts payable	1,529	1,253
Accrued expenses	692	788
Payables to affiliates	125	107
Borrowings from Exelon intercompany money pool	—	285
Mark-to-market derivative liabilities	392	262
Unamortized energy contract liabilities	5	7
Renewable energy credit obligation	645	661
Liabilities held for sale	3	375
Other	371	444
Total current liabilities	<u>6,298</u>	<u>5,219</u>
Long-term debt	5,038	5,566
Long-term debt to affiliates	323	324
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,542	3,656
Asset retirement obligations	12,157	12,054
Non-pension postretirement benefit obligations	857	858
Spent nuclear fuel obligation	1,208	1,208
Payables to affiliates	2,865	3,017
Mark-to-market derivative liabilities	190	205
Unamortized energy contract liabilities	3	3
Other	1,405	1,308
Total deferred credits and other liabilities	<u>22,227</u>	<u>22,309</u>
Total liabilities ^(a)	<u>33,886</u>	<u>33,418</u>
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,624	9,624
Undistributed earnings	1,554	2,805
Accumulated other comprehensive loss, net	(29)	(30)
Total member's equity	<u>11,149</u>	<u>12,399</u>
Noncontrolling interests	2,291	2,277
Total equity	<u>13,440</u>	<u>14,676</u>
Total liabilities and equity	\$ <u>47,326</u>	\$ <u>48,094</u>

(a) Generation's consolidated assets include \$9,967 million and \$10,182 million at March 31, 2021 and December 31, 2020, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include \$3,557 million and \$3,572 million at March 31, 2021 and December 31, 2020, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 16 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Unaudited)

Three Months Ended March 31, 2021					
(In millions)	Member's Equity				Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	
Balance, December 31, 2020	\$ 9,624	\$ 2,805	\$ (30)	\$ 2,277	\$ 14,676
Net (loss) income	—	(793)	—	24	(769)
Changes in equity of noncontrolling interests	—	—	—	(10)	(10)
Distributions to member	—	(458)	—	—	(458)
Other comprehensive income, net of income taxes	—	—	1	—	1
Balance, March 31, 2021	\$ 9,624	\$ 1,554	\$ (29)	\$ 2,291	\$ 13,440

Three Months Ended March 31, 2020					
(In millions)	Member's Equity				Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	
Balance, December 31, 2019	\$ 9,566	\$ 3,950	\$ (32)	\$ 2,346	\$ 15,830
Net income (loss)	—	45	—	(206)	(161)
Changes in equity of noncontrolling interests	—	—	—	(11)	(11)
Sale of noncontrolling interests	2	—	—	—	2
Distributions to member	—	(468)	—	—	(468)
Other comprehensive loss, net of income taxes	—	—	(9)	—	(9)
Balance, March 31, 2020	\$ 9,568	\$ 3,527	\$ (41)	\$ 2,129	\$ 15,183

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 March 31,	
	2021	2020
Operating revenues		
Electric operating revenues	\$ 1,475	\$ 1,422
Revenues from alternative revenue programs	54	12
Operating revenues from affiliates	6	5
Total operating revenues	1,535	1,439
Operating expenses		
Purchased power	442	389
Purchased power from affiliate	85	97
Operating and maintenance	245	243
Operating and maintenance from affiliates	71	74
Depreciation and amortization	292	273
Taxes other than income taxes	75	75
Total operating expenses	1,210	1,151
Operating income	325	288
Other income and (deductions)		
Interest expense, net	(93)	(91)
Interest expense to affiliates	(3)	(3)
Other, net	7	10
Total other income and (deductions)	(89)	(84)
Income before income taxes	236	204
Income taxes	39	36
Net income	\$ 197	\$ 168
Comprehensive income	\$ 197	\$ 168

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

(In millions)	Three Months Ended March 31,	
	2021	2020
Cash flows from operating activities		
Net income	\$ 197	\$ 168
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	292	273
Deferred income taxes and amortization of investment tax credits	63	42
Other non-cash operating activities	(9)	16
Changes in assets and liabilities:		
Accounts receivable	23	9
Receivables from and payables to affiliates, net	(15)	(6)
Inventories	(1)	(2)
Accounts payable and accrued expenses	(176)	(147)
Collateral received (posted), net	5	3
Income taxes	(23)	(7)
Pension and non-pension postretirement benefit contributions	(171)	(143)
Other assets and liabilities	(159)	(132)
Net cash flows provided by operating activities	26	74
Cash flows from investing activities		
Capital expenditures	(613)	(506)
Other investing activities	7	5
Net cash flows used in investing activities	(606)	(501)
Cash flows from financing activities		
Changes in short-term borrowings	(188)	(130)
Issuance of long-term debt	700	1,000
Dividends paid on common stock	(127)	(125)
Contributions from parent	198	125
Other financing activities	(9)	(13)
Net cash flows provided by financing activities	574	857
(Decrease) increase in cash, restricted cash, and cash equivalents	(6)	430
Cash, restricted cash, and cash equivalents at beginning of period	405	403
Cash, restricted cash, and cash equivalents at end of period	\$ 399	\$ 833
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (107)	\$ (5)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	\$ 86	\$ 83
Restricted cash and cash equivalents	270	279
Accounts receivable		
Customer accounts receivable	626	656
Customer allowance for credit losses	(103)	(97)
Customer accounts receivable, net	523	559
Other accounts receivable	243	239
Other allowance for credit losses	(22)	(21)
Other accounts receivable, net	221	218
Receivables from affiliates	21	22
Inventories, net	170	170
Regulatory assets	294	279
Other	55	49
Total current assets	1,640	1,659
Property, plant, and equipment (net of accumulated depreciation and amortization of \$5,811 and \$5,672 as of March 31, 2021 and December 31, 2020, respectively)	24,840	24,557
Deferred debits and other assets		
Regulatory assets	1,840	1,749
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,375	2,541
Prepaid pension asset	1,165	1,022
Other	334	307
Total deferred debits and other assets	8,345	8,250
Total assets	\$ 34,825	\$ 34,466

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	\$ 135	\$ 323
Long-term debt due within one year	350	350
Accounts payable	533	683
Accrued expenses	242	390
Payables to affiliates	80	96
Customer deposits	84	86
Regulatory liabilities	360	289
Mark-to-market derivative liabilities	31	33
Other	128	143
Total current liabilities	1,943	2,393
Long-term debt	9,324	8,633
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,427	4,341
Asset retirement obligations	127	126
Non-pension postretirement benefits obligations	177	173
Regulatory liabilities	6,172	6,403
Mark-to-market derivative liabilities	264	268
Other	589	595
Total deferred credits and other liabilities	11,756	11,906
Total liabilities	23,228	23,137
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	8,483	8,285
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	3,165	3,095
Total shareholders' equity	11,597	11,329
Total liabilities and shareholders' equity	\$ 34,825	\$ 34,466

See the Combined Notes to Consolidated Financial Statements

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

Three Months Ended March 31, 2021					
(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2020	\$ 1,588	\$ 8,285	\$ (1,639)	\$ 3,095	\$ 11,329
Net income	—	—	197	—	197
Appropriation of retained earnings for future dividends	—	—	(197)	197	—
Common stock dividends	—	—	—	(127)	(127)
Contributions from parent	—	198	—	—	198
Balance, March 31, 2021	<u>\$ 1,588</u>	<u>\$ 8,483</u>	<u>\$ (1,639)</u>	<u>\$ 3,165</u>	<u>\$ 11,597</u>
Three Months Ended March 31, 2020					
(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2019	\$ 1,588	\$ 7,572	\$ (1,639)	\$ 3,156	\$ 10,677
Net income	—	—	168	—	168
Appropriation of retained earnings for future dividends	—	—	(168)	168	—
Common stock dividends	—	—	—	(125)	(125)
Contributions from parent	—	125	—	—	125
Balance, March 31, 2020	<u>\$ 1,588</u>	<u>\$ 7,697</u>	<u>\$ (1,639)</u>	<u>\$ 3,199</u>	<u>\$ 10,845</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 March 31,	
	2021	2020
Operating revenues		
Electric operating revenues	\$ 649	\$ 600
Natural gas operating revenues	228	209
Revenues from alternative revenue programs	10	2
Operating revenues from affiliates	2	2
Total operating revenues	889	813
Operating expenses		
Purchased power	189	164
Purchased fuel	86	83
Purchased power from affiliate	41	36
Operating and maintenance	193	179
Operating and maintenance from affiliates	41	38
Depreciation and amortization	86	86
Taxes other than income taxes	43	39
Total operating expenses	679	625
Operating income	210	188
Other income and (deductions)		
Interest expense, net	(35)	(33)
Interest expense to affiliates	(3)	(3)
Other, net	5	3
Total other income and (deductions)	(33)	(33)
Income before income taxes	177	155
Income taxes	10	15
Net income	\$ 167	\$ 140
Comprehensive income	\$ 167	\$ 140

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,	
	2021	2020
Cash flows from operating activities		
Net income	\$ 167	\$ 140
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	86	86
Deferred income taxes and amortization of investment tax credits	6	2
Other non-cash operating activities	12	22
Changes in assets and liabilities:		
Accounts receivable	(5)	14
Receivables from and payables to affiliates, net	(2)	(3)
Inventories	13	15
Accounts payable and accrued expenses	(36)	(45)
Income taxes	3	14
Pension and non-pension postretirement benefit contributions	(16)	(16)
Other assets and liabilities	(103)	(84)
Net cash flows provided by operating activities	125	145
Cash flows from investing activities		
Capital expenditures	(295)	(259)
Changes in Exelon intercompany money pool	(48)	(22)
Other investing activities	1	1
Net cash flows used in investing activities	(342)	(280)
Cash flows from financing activities		
Issuance of long-term debt	375	—
Changes in Exelon intercompany money pool	(40)	—
Dividends paid on common stock	(85)	(85)
Contributions from parent	—	231
Other financing activities	(4)	—
Net cash flows provided by financing activities	246	146
Increase in cash, restricted cash, and cash equivalents	29	11
Cash, restricted cash, and cash equivalents at beginning of period	26	27
Cash, restricted cash, and cash equivalents at end of period	\$ 55	\$ 38
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (44)	\$ (11)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	\$ 48	\$ 19
Restricted cash and cash equivalents	7	7
Accounts receivable		
Customer accounts receivable	499	511
Customer allowance for credit losses	(130)	(116)
Customer accounts receivable, net	369	395
Other accounts receivable	140	130
Other allowance for credit losses	(11)	(8)
Other accounts receivable, net	129	122
Receivables from affiliates	—	2
Receivable from Exelon intercompany money pool	48	—
Inventories, net		
Fossil fuel	15	33
Materials and supplies	43	38
Prepaid utility taxes	103	—
Regulatory assets	29	25
Other	22	21
Total current assets	813	662
Property, plant, and equipment (net of accumulated depreciation and amortization of \$3,897 and \$3,843 as of March 31, 2021 and December 31, 2020, respectively)	10,352	10,181
Deferred debits and other assets		
Regulatory assets	828	776
Investments	30	30
Receivables from affiliates	490	475
Prepaid pension asset	389	375
Other	35	32
Total deferred debits and other assets	1,772	1,688
Total assets	\$ 12,937	\$ 12,531

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	\$ 300	\$ 300
Accounts payable	431	479
Accrued expenses	100	129
Payables to affiliates	46	50
Borrowings from Exelon intercompany money pool	—	40
Customer deposits	54	59
Regulatory liabilities	127	121
Other	31	30
Total current liabilities	1,089	1,208
Long-term debt	3,825	3,453
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,297	2,242
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	286	286
Regulatory liabilities	519	503
Other	93	93
Total deferred credits and other liabilities	3,224	3,153
Total liabilities	8,322	7,998
Commitments and contingencies		
Shareholder's equity		
Common stock	3,014	3,014
Retained earnings	1,601	1,519
Total shareholder's equity	4,615	4,533
Total liabilities and shareholder's equity	\$ 12,937	\$ 12,531

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

(In millions)	Three Months Ended March 31, 2021		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2020	\$ 3,014	\$ 1,519	\$ 4,533
Net income	—	167	167
Common stock dividends	—	(85)	(85)
Balance, March 31, 2021	\$ 3,014	\$ 1,601	\$ 4,615

(In millions)	Three Months Ended March 31, 2020		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	\$ 2,766	\$ 1,412	\$ 4,178
Net income	—	140	140
Common stock dividends	—	(85)	(85)
Contributions from parent	231	—	231
Balance, March 31, 2020	\$ 2,997	\$ 1,467	\$ 4,464

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2021	2020
Operating revenues		
Electric operating revenues	\$ 620	\$ 595
Natural gas operating revenues	330	300
Revenues from alternative revenue programs	18	36
Operating revenues from affiliates	6	6
Total operating revenues	<u>974</u>	<u>937</u>
Operating expenses		
Purchased power	162	114
Purchased fuel	99	76
Purchased power and fuel from affiliate	70	98
Operating and maintenance	152	146
Operating and maintenance from affiliates	45	42
Depreciation and amortization	152	143
Taxes other than income taxes	72	69
Total operating expenses	<u>752</u>	<u>688</u>
Operating income	<u>222</u>	<u>249</u>
Other income and (deductions)		
Interest expense, net	(34)	(32)
Other, net	8	5
Total other income and (deductions)	<u>(26)</u>	<u>(27)</u>
Income before income taxes	196	222
Income taxes	(13)	41
Net income	<u>\$ 209</u>	<u>\$ 181</u>
Comprehensive income	<u>\$ 209</u>	<u>\$ 181</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,	
	2021	2020
Cash flows from operating activities		
Net income	\$ 209	\$ 181
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	152	143
Deferred income taxes and amortization of investment tax credits	(4)	33
Other non-cash operating activities	2	(8)
Changes in assets and liabilities:		
Accounts receivable	12	(28)
Receivables from and payables to affiliates, net	(15)	(13)
Inventories	9	20
Accounts payable and accrued expenses	(59)	(9)
Income taxes	(9)	7
Pension and non-pension postretirement benefit contributions	(65)	(64)
Other assets and liabilities	(103)	10
Net cash flows provided by operating activities	129	272
Cash flows from investing activities		
Capital expenditures	(336)	(283)
Other investing activities	2	(6)
Net cash flows used in investing activities	(334)	(289)
Cash flows from financing activities		
Changes in short-term borrowings	156	66
Dividends paid on common stock	(74)	(62)
Net cash flows provided by financing activities	82	4
Decrease in cash, restricted cash, and cash equivalents	(123)	(13)
Cash, restricted cash, and cash equivalents at beginning of period	145	25
Cash, restricted cash, and cash equivalents at end of period	\$ 22	\$ 12
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (80)	\$ (35)

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

<u>(In millions)</u>	<u>March 31, 2021</u>	<u>December 31, 2020</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 21	\$ 144
Restricted cash and cash equivalents	1	1
Accounts receivable		
Customer accounts receivable	476	487
Customer allowance for credit losses	(43)	(35)
Customer accounts receivable, net	433	452
Other accounts receivable	125	117
Other allowance for credit losses	(9)	(9)
Other accounts receivable, net	116	108
Receivables from affiliates	—	3
Inventories, net		
Fossil fuel	12	25
Materials and supplies	45	41
Prepaid utility taxes	43	—
Regulatory assets	179	168
Other	9	6
Total current assets	859	948
Property, plant, and equipment (net of accumulated depreciation and amortization of \$4,115 and \$4,034 as of March 31, 2021 and December 31, 2020, respectively)	10,026	9,872
Deferred debits and other assets		
Regulatory assets	481	481
Investments	10	10
Prepaid pension asset	314	270
Other	69	69
Total deferred debits and other assets	874	830
Total assets	\$ 11,759	\$ 11,650

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ 156	\$ —
Long-term debt due within one year	300	300
Accounts payable	266	346
Accrued expenses	142	205
Payables to affiliates	43	61
Customer deposits	105	110
Regulatory liabilities	41	30
Other	83	91
Total current liabilities	1,136	1,143
Long-term debt	3,365	3,364
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,609	1,521
Asset retirement obligations	24	23
Non-pension postretirement benefits obligations	182	189
Regulatory liabilities	1,016	1,109
Other	95	104
Total deferred credits and other liabilities	2,926	2,946
Total liabilities	7,427	7,453
Commitments and contingencies		
Shareholder's equity		
Common stock	2,318	2,318
Retained earnings	2,014	1,879
Total shareholder's equity	4,332	4,197
Total liabilities and shareholder's equity	\$ 11,759	\$ 11,650

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, 2021		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2020	\$ 2,318	\$ 1,879	\$ 4,197
Net income	—	209	209
Common stock dividends	—	(74)	(74)
Balance, March 31, 2021	\$ 2,318	\$ 2,014	\$ 4,332

(In millions)	Three Months Ended March 31, 2020		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	\$ 1,907	\$ 1,776	\$ 3,683
Net income	—	181	181
Common stock dividends	—	(62)	(62)
Balance, March 31, 2020	\$ 1,907	\$ 1,895	\$ 3,802

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 March 31,	
	2021	2020
Operating revenues		
Electric operating revenues	\$ 1,124	\$ 1,086
Natural gas operating revenues	71	64
Revenues from alternative revenue programs	46	18
Operating revenues from affiliates	3	3
Total operating revenues	1,244	1,171
Operating expenses		
Purchased power	348	300
Purchased fuel	33	31
Purchased power from affiliates	98	104
Operating and maintenance	216	219
Operating and maintenance from affiliates	40	38
Depreciation and amortization	210	194
Taxes other than income taxes	113	114
Total operating expenses	1,058	1,000
Gain on sales of assets	—	2
Operating income	186	173
Other income and (deductions)		
Interest expense, net	(67)	(67)
Other, net	17	13
Total other income and (deductions)	(50)	(54)
Income before income taxes	136	119
Income taxes	8	11
Net income	\$ 128	\$ 108
Comprehensive income	\$ 128	\$ 108

See the Combined Notes to Consolidated Financial Statements

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2021	2020
Cash flows from operating activities		
Net income	\$ 128	\$ 108
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	210	194
Deferred income taxes and amortization of investment tax credits	4	(4)
Other non-cash operating activities	(25)	7
Changes in assets and liabilities:		
Accounts receivable	56	36
Receivables from and payables to affiliates, net	(18)	(17)
Inventories	5	8
Accounts payable and accrued expenses	(24)	(16)
Income taxes	3	15
Pension and non-pension postretirement benefit contributions	(36)	(27)
Other assets and liabilities	(94)	(72)
Net cash flows provided by operating activities	209	232
Cash flows from investing activities		
Capital expenditures	(456)	(376)
Other investing activities	1	1
Net cash flows used in investing activities	(455)	(375)
Cash flows from financing activities		
Changes in short-term borrowings	(368)	(100)
Issuance of long-term debt	625	150
Retirement of long-term debt	(44)	(6)
Changes in Exelon intercompany money pool	3	7
Distributions to member	(81)	(134)
Contributions from member	560	144
Other financing activities	(5)	(1)
Net cash flows provided by financing activities	690	60
Increase (decrease) in cash, restricted cash, and cash equivalents	444	(83)
Cash, restricted cash, and cash equivalents at beginning of period	160	181
Cash, restricted cash, and cash equivalents at end of period	\$ 604	\$ 98
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (33)	\$ (57)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	\$ 558	\$ 111
Restricted cash and cash equivalents	37	39
Accounts receivable		
Customer accounts receivable	557	611
Customer allowance for credit losses	(101)	(86)
Customer accounts receivable, net	456	525
Other accounts receivable	261	260
Other allowance for credit losses	(37)	(33)
Other accounts receivable, net	224	227
Receivables from affiliates	—	8
Inventories, net		
Fossil fuel	3	6
Materials and supplies	196	198
Regulatory assets	450	440
Other	52	45
Total current assets	1,976	1,599
Property, plant, and equipment (net of accumulated depreciation and amortization of \$1,930 and \$1,811 as of March 31, 2021 and December 31, 2020, respectively)	15,651	15,377
Deferred debits and other assets		
Regulatory assets	1,912	1,933
Investments	141	140
Goodwill	4,005	4,005
Prepaid pension asset	383	365
Deferred income taxes	9	10
Other	310	307
Total deferred debits and other assets	6,760	6,760
Total assets^(a)	\$ 24,387	\$ 23,736

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2021	December 31, 2020
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ —	\$ 368
Long-term debt due within one year	304	347
Accounts payable	503	539
Accrued expenses	279	299
Payables to affiliates	78	104
Borrowings from Exelon intercompany money pool	24	21
Customer deposits	96	106
Regulatory liabilities	130	137
Unamortized energy contract liabilities	92	92
Other	137	141
Total current liabilities	<u>1,643</u>	<u>2,154</u>
Long-term debt	<u>7,273</u>	<u>6,659</u>
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,481	2,439
Asset retirement obligations	59	59
Non-pension postretirement benefit obligations	80	86
Regulatory liabilities	1,391	1,438
Unamortized energy contract liabilities	214	235
Other	595	622
Total deferred credits and other liabilities	<u>4,820</u>	<u>4,879</u>
Total liabilities ^(a)	<u>13,736</u>	<u>13,692</u>
Commitments and contingencies		
Member's equity		
Membership interest	10,672	10,112
Undistributed losses	(21)	(68)
Total member's equity	<u>10,651</u>	<u>10,044</u>
Total liabilities and member's equity	<u>\$ 24,387</u>	<u>\$ 23,736</u>

(a) PHI's consolidated total assets include \$18 million at both March 31, 2021 and December 31, 2020 of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include \$21 million and \$26 million at March 31, 2021 and December 31, 2020, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 16 — Variable Interest Entities for additional information.

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

(In millions)	Three Months Ended March 31, 2021		
	Membership Interest	Undistributed (Losses)/ Earnings	Total Member's Equity
Balance, December 31, 2020	\$ 10,112	\$ (68)	\$ 10,044
Net income	—	128	128
Distributions to member	—	(81)	(81)
Contributions from member	560	—	560
Balance, March 31, 2021	\$ 10,672	\$ (21)	\$ 10,651

(In millions)	Three Months Ended March 31, 2020		
	Membership Interest	Undistributed (Losses)/ Earnings	Total Member's Equity
Balance, December 31, 2019	\$ 9,618	\$ (10)	\$ 9,608
Net income	—	108	108
Distributions to member	—	(134)	(134)
Contributions from member	144	—	144
Balance, March 31, 2020	\$ 9,762	\$ (36)	\$ 9,726

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,	
	2021	2020
Operating revenues		
Electric operating revenues	\$ 526	\$ 528
Revenues from alternative revenue programs	26	15
Operating revenues from affiliates	1	1
Total operating revenues	553	544
Operating expenses		
Purchased power	92	85
Purchased power from affiliate	74	79
Operating and maintenance	56	60
Operating and maintenance from affiliates	52	51
Depreciation and amortization	102	95
Taxes other than income taxes	90	92
Total operating expenses	466	462
Operating income	87	82
Other income and (deductions)		
Interest expense, net	(34)	(34)
Other, net	12	9
Total other income and (deductions)	(22)	(25)
Income before income taxes	65	57
Income taxes	6	5
Net income	\$ 59	\$ 52
Comprehensive income	\$ 59	\$ 52

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)**

<i>(In millions)</i>	Three Months Ended March 31,	
	2021	2020
Cash flows from operating activities		
Net income	\$ 59	\$ 52
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	102	95
Deferred income taxes and amortization of investment tax credits	4	(2)
Other non-cash operating activities	(25)	(11)
Changes in assets and liabilities:		
Accounts receivable	26	14
Receivables from and payables to affiliates, net	(9)	(11)
Inventories	1	3
Accounts payable and accrued expenses	—	6
Income taxes	2	6
Pension and non-pension postretirement benefit contributions	(5)	(4)
Other assets and liabilities	(58)	(38)
Net cash flows provided by operating activities	97	110
Cash flows from investing activities		
Capital expenditures	(220)	(180)
Changes in PHI intercompany money pool	—	(114)
Other investing activities	1	(4)
Net cash flows used in investing activities	(219)	(298)
Cash flows from financing activities		
Changes in short-term borrowings	(35)	(82)
Issuance of long-term debt	150	150
Dividends paid on common stock	(28)	(28)
Contributions from parent	138	137
Other financing activities	(1)	(1)
Net cash flows provided by financing activities	224	176
Increase (decrease) in cash, restricted cash, and cash equivalents	102	(12)
Cash, restricted cash, and cash equivalents at beginning of period	65	63
Cash, restricted cash, and cash equivalents at end of period	\$ 167	\$ 51
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (16)	\$ (43)

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)**

(In millions)	March 31, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	\$ 134	\$ 30
Restricted cash and cash equivalents	33	35
Accounts receivable		
Customer accounts receivable	252	279
Customer allowance for credit losses	(41)	(32)
Customer accounts receivable, net	211	247
Other accounts receivable	138	131
Other allowance for credit losses	(15)	(13)
Other accounts receivable, net	123	118
Receivables from affiliates	—	2
Inventories, net	110	111
Regulatory assets	224	214
Other	19	13
Total current assets	854	770
Property, plant, and equipment (net of accumulated depreciation and amortization of \$3,746 and \$3,697 as of March 31, 2021 and December 31, 2020, respectively)	7,606	7,456
Deferred debits and other assets		
Regulatory assets	563	570
Investments	116	115
Prepaid pension asset	283	284
Other	71	69
Total deferred debits and other assets	1,033	1,038
Total assets	\$ 9,493	\$ 9,264

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)**

(In millions)	March 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ —	\$ 35
Long-term debt due within one year	4	3
Accounts payable	213	226
Accrued expenses	165	164
Payables to affiliates	44	55
Customer deposits	45	51
Regulatory liabilities	39	46
Merger related obligation	33	33
Current portion of DC PLUG obligation	30	30
Other	30	31
Total current liabilities	<u>603</u>	<u>674</u>
Long-term debt	3,313	3,162
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,209	1,189
Asset retirement obligations	39	39
Non-pension postretirement benefit obligations	9	13
Regulatory liabilities	624	644
Other	324	340
Total deferred credits and other liabilities	<u>2,205</u>	<u>2,225</u>
Total liabilities	<u>6,121</u>	<u>6,061</u>
Commitments and contingencies		
Shareholder's equity		
Common stock	2,196	2,058
Retained earnings	1,176	1,145
Total shareholder's equity	<u>3,372</u>	<u>3,203</u>
Total liabilities and shareholder's equity	<u>\$ 9,493</u>	<u>\$ 9,264</u>

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, 2021		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2020	\$ 2,058	\$ 1,145	\$ 3,203
Net income	—	59	59
Common stock dividends	—	(28)	(28)
Contributions from parent	138	—	138
Balance, March 31, 2021	\$ 2,196	\$ 1,176	\$ 3,372

(In millions)	Three Months Ended March 31, 2020		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	\$ 1,796	\$ 1,111	\$ 2,907
Net income	—	52	52
Common stock dividends	—	(28)	(28)
Contributions from parent	137	—	137
Balance, March 31, 2020	\$ 1,933	\$ 1,135	\$ 3,068

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,	
	2021	2020
Operating revenues		
Electric operating revenues	\$ 300	\$ 283
Natural gas operating revenues	71	64
Revenues from alternative revenue programs	9	1
Operating revenues from affiliates	2	2
Total operating revenues	<u>382</u>	<u>350</u>
Operating expenses		
Purchased power	103	88
Purchased fuel	33	31
Purchased power from affiliates	20	22
Operating and maintenance	44	42
Operating and maintenance from affiliates	39	37
Depreciation and amortization	53	48
Taxes other than income taxes	17	16
Total operating expenses	<u>309</u>	<u>284</u>
Operating income	<u>73</u>	<u>66</u>
Other income and (deductions)		
Interest expense, net	(15)	(16)
Other, net	3	2
Total other income and (deductions)	<u>(12)</u>	<u>(14)</u>
Income before income taxes	<u>61</u>	<u>52</u>
Income taxes	5	7
Net income	<u>\$ 56</u>	<u>\$ 45</u>
Comprehensive income	<u>\$ 56</u>	<u>\$ 45</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,	
	2021	2020
Cash flows from operating activities		
Net income	\$ 56	\$ 45
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	53	48
Deferred income taxes and amortization of investment tax credits	2	—
Other non-cash operating activities	(1)	2
Changes in assets and liabilities:		
Accounts receivable	15	14
Receivables from and payables to affiliates, net	(11)	(9)
Inventories	2	3
Accounts payable and accrued expenses	11	4
Income taxes	3	7
Other assets and liabilities	(26)	(10)
Net cash flows provided by operating activities	104	104
Cash flows from investing activities		
Capital expenditures	(112)	(95)
Other investing activities	—	(4)
Net cash flows used in investing activities	(112)	(99)
Cash flows from financing activities		
Changes in short-term borrowings	(146)	(2)
Issuance of long-term debt	125	—
Changes in PHI intercompany money pool	—	37
Dividends paid on common stock	(40)	(52)
Contributions from parent	120	6
Other financing activities	(2)	—
Net cash flows provided by (used in) financing activities	57	(11)
Increase (decrease) in cash and cash equivalents	49	(6)
Cash and cash equivalents at beginning of period	15	13
Cash and cash equivalents at end of period	\$ 64	\$ 7
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (15)	\$ (9)

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	\$ 64	\$ 15
Accounts receivable		
Customer accounts receivable	160	176
Customer allowance for credit losses	(25)	(22)
Customer accounts receivable, net	135	154
Other accounts receivable	66	68
Other allowance for credit losses	(10)	(9)
Other accounts receivable, net	56	59
Receivables from affiliates	—	1
Inventories, net		
Fossil fuel	2	6
Materials and supplies	53	51
Prepaid utility taxes	10	11
Regulatory assets	65	58
Renewable energy credits	14	10
Other	2	3
Total current assets	401	368
Property, plant, and equipment (net of accumulated depreciation and amortization of \$1,563 and \$1,533 as of March 31, 2021 and December 31, 2020, respectively)	4,368	4,314
Deferred debits and other assets		
Regulatory assets	226	222
Goodwill	8	8
Prepaid pension asset	161	162
Other	68	66
Total deferred debits and other assets	463	458
Total assets	\$ 5,232	\$ 5,140

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ —	\$ 146
Long-term debt due within one year	82	82
Accounts payable	119	126
Accrued expenses	49	46
Payables to affiliates	24	36
Customer deposits	30	32
Regulatory liabilities	49	47
Other	19	20
Total current liabilities	372	535
Long-term debt	1,720	1,595
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	734	715
Asset retirement obligations	14	14
Non-pension postretirement benefits obligations	14	15
Regulatory liabilities	474	493
Other	92	97
Total deferred credits and other liabilities	1,328	1,334
Total liabilities	3,420	3,464
Commitments and contingencies		
Shareholder's equity		
Common stock	1,209	1,089
Retained earnings	603	587
Total shareholder's equity	1,812	1,676
Total liabilities and shareholder's equity	\$ 5,232	\$ 5,140

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended March 31, 2021		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2020	\$ 1,089	\$ 587	\$ 1,676
Net income	—	56	56
Common stock dividends	—	(40)	(40)
Contributions from parent	120	—	120
Balance, March 31, 2021	\$ 1,209	\$ 603	\$ 1,812

(In millions)	Three Months Ended March 31, 2020		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	\$ 977	\$ 603	\$ 1,580
Net income	—	45	45
Common stock dividends	—	(52)	(52)
Contributions from parent	6	—	6
Balance, March 31, 2020	\$ 983	\$ 596	\$ 1,579

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,	
	2021	2020
Operating revenues		
Electric operating revenues	\$ 298	\$ 274
Revenues from alternative revenue programs	11	1
Operating revenues from affiliates	1	1
Total operating revenues	<u>310</u>	<u>276</u>
Operating expenses		
Purchased power	153	126
Purchased power from affiliate	4	2
Operating and maintenance	42	45
Operating and maintenance from affiliates	34	33
Depreciation and amortization	47	43
Taxes other than income taxes	2	2
Total operating expenses	<u>282</u>	<u>251</u>
Gain on sale of assets	<u>—</u>	<u>2</u>
Operating income	<u>28</u>	<u>27</u>
Other income and (deductions)		
Interest expense, net	(15)	(14)
Interest expense to affiliates, net	—	(1)
Other, net	1	2
Total other income and (deductions)	<u>(14)</u>	<u>(13)</u>
Income before income taxes	<u>14</u>	<u>14</u>
Income taxes	<u>—</u>	<u>1</u>
Net income	<u>\$ 14</u>	<u>\$ 13</u>
Comprehensive income	<u>\$ 14</u>	<u>\$ 13</u>

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,	
	2021	2020
Cash flows from operating activities		
Net income	\$ 14	\$ 13
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	47	43
Deferred income taxes and amortization of investment tax credits	(1)	(1)
Other non-cash operating activities	(7)	4
Changes in assets and liabilities:		
Accounts receivable	13	11
Receivables from and payables to affiliates, net	1	3
Inventories	3	2
Accounts payable and accrued expenses	(11)	3
Income taxes	1	2
Pension and non-pension postretirement benefit contributions	(3)	(2)
Other assets and liabilities	(3)	(22)
Net cash flows provided by operating activities	54	56
Cash flows from investing activities		
Capital expenditures	(123)	(101)
Other investing activities	—	6
Net cash flows used in investing activities	(123)	(95)
Cash flows from financing activities		
Changes in short-term borrowings	(187)	(16)
Issuance of long-term debt	350	—
Retirement of long-term debt	(44)	(5)
Changes in PHI intercompany money pool	—	77
Dividends paid on common stock	(14)	(23)
Contributions from parent	303	1
Other financing activities	(3)	—
Net cash flows provided by financing activities	405	34
Increase (decrease) in cash, restricted cash, and cash equivalents	336	(5)
Cash, restricted cash, and cash equivalents at beginning of period	30	28
Cash, restricted cash, and cash equivalents at end of period	\$ 366	\$ 23
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (2)	\$ (4)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	\$ 353	\$ 17
Restricted cash and cash equivalents	4	3
Accounts receivable		
Customer accounts receivable	146	156
Customer allowance for credit losses	(35)	(32)
Customer accounts receivable, net	111	124
Other accounts receivable	69	72
Other allowance for credit losses	(12)	(11)
Other accounts receivable, net	57	61
Receivables from affiliates	1	6
Inventories, net	34	37
Regulatory assets	69	75
Other	2	3
Total current assets	631	326
Property, plant, and equipment (net of accumulated depreciation and amortization of \$1,329 and \$1,303 as of March 31, 2021 and December 31, 2020, respectively)	3,552	3,475
Deferred debits and other assets		
Regulatory assets	407	395
Prepaid pension asset	39	40
Other	50	50
Total deferred debits and other assets	496	485
Total assets^(a)	\$ 4,679	\$ 4,286

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ —	\$ 187
Long-term debt due within one year	218	261
Accounts payable	162	177
Accrued expenses	48	46
Payables to affiliates	27	31
Customer deposits	21	23
Regulatory liabilities	41	44
Other	9	11
Total current liabilities	526	780
Long-term debt	1,500	1,152
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	629	624
Non-pension postretirement benefit obligations	16	17
Regulatory liabilities	266	274
Other	48	48
Total deferred credits and other liabilities	959	963
Total liabilities ^(a)	2,985	2,895
Commitments and contingencies		
Shareholder's equity		
Common stock	1,574	1,271
Retained earnings	120	120
Total shareholder's equity	1,694	1,391
Total liabilities and shareholder's equity	\$ 4,679	\$ 4,286

(a) ACE's consolidated total assets include \$13 million at both March 31, 2021 and December 31, 2020, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated total liabilities include \$16 million and \$21 million at March 31, 2021 and December 31, 2020, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 16 — Variable Interest Entities for additional information.

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

(In millions)	Three Months Ended March 31, 2021		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2020	\$ 1,271	\$ 120	\$ 1,391
Net income	—	14	14
Common stock dividends	—	(14)	(14)
Contributions from parent	303	—	303
Balance, March 31, 2021	\$ 1,574	\$ 120	\$ 1,694

(In millions)	Three Months Ended March 31, 2020		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	\$ 1,154	\$ 122	\$ 1,276
Net income	—	13	13
Common stock dividends	—	(23)	(23)
Contributions from parent	1	—	1
Balance, March 31, 2020	\$ 1,155	\$ 112	\$ 1,267

See the Combined Notes to Consolidated Financial Statements

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

Note 1 — Significant Accounting Policies

1. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

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

Name of Registrant	Business	Service Territories
Exelon Generation Company, LLC	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy, and other energy-related products and services.	Five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions
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 (All Registrants)

This is a combined quarterly report of all Registrants. The Notes to the Consolidated Financial Statements apply to the Registrants as indicated parenthetically next to each corresponding disclosure. When appropriate, the Registrants are named specifically for their related activities and disclosures. Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology, and supply management services. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, accounting, 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" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

The accompanying consolidated financial statements as of March 31, 2021 and for the three months ended March 31, 2021 and 2020 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

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

Note 1 — Significant Accounting Policies

December 31, 2020 Consolidated Balance Sheets were derived from audited financial statements. 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, 2021. 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.

2. Mergers, Acquisitions, and Dispositions (Exelon and Generation)

CENG Put Option (Exelon and Generation)

Generation owns a 50.01% membership interest in CENG, a joint venture with EDF, which wholly owns the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to an 82% undivided ownership interest in Nine Mile Point Unit 2. CENG is 100% consolidated in Exelon's and Generation's financial statements. See Note 16 — Variable Interest Entities for additional information.

On April 1, 2014, Generation and EDF entered into various agreements including a NOSA, an amended LLC Operating Agreement, an Employee Matters Agreement, and a Put Option Agreement, among others. Under the amended LLC Operating Agreement, CENG made a \$400 million special distribution to EDF and committed to make preferred distributions to Generation until Generation has received aggregate distributions of \$400 million plus a return of 8.50% per annum.

Under the terms of the Put Option Agreement, EDF has the option to sell its 49.99% equity interest in CENG to Generation exercisable beginning on January 1, 2016 and thereafter until June 30, 2022. The Put Option Agreement's terms also provide that in the event the put closing has not been completed prior to the 18-month anniversary of the exercise date, EDF may withdraw its exercise notice. In the event of a withdrawal, EDF retains the right to exercise the put option until the later of June 30, 2022 and 18 months following the date of withdrawal, but in no event later than January 1, 2024. EDF is not entitled to this withdrawal right in the event it breaches any provision of the Put Option Agreement that results in the failure of the put to close on or before the 18-month anniversary of the exercise date.

The Put Option Agreement provides that the purchase price is to be determined by agreement of the parties, or absent such agreement, by a third-party arbitration process. The third parties determining fair market value of EDF's 49.99% interest are to take into consideration all rights and obligations under the LLC Operating Agreement and Employee Matters Agreement including but not limited to Generation's rights with respect to any unpaid aggregate preferred distributions and the related return. As of March 31, 2021, the total unpaid aggregate preferred distributions and related return owed to Generation is \$632 million.

On November 20, 2019, Generation received notice of EDF's intention to exercise the put option to sell its interest in CENG to Generation, and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period. At this time, Generation cannot reasonably predict the ultimate purchase price that will be paid to EDF for its interest in CENG. The transaction required approval by the FERC and the NYPSC, which approvals were received on July 30, 2020 and April 15, 2021, respectively. The sale process is currently expected to close in the second half of 2021.

Agreement for Sale of Generation's Solar Business (Exelon and Generation)

On December 8, 2020, Generation entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of Generation's solar business, including 360 MW of generation in operation or under construction across more than 600 sites across the United States. Generation will retain certain solar assets not included in this agreement, primarily Antelope Valley.

Completion of the transaction contemplated by the sale agreement was subject to the satisfaction of several closing conditions which were satisfied in the first quarter of 2021. The sale was completed on March 31, 2021 for a purchase price of \$810 million. Generation received cash proceeds of \$675 million, net of \$125 million long-term debt assumed by the buyer and certain working capital and other post-closing adjustments. Exelon and

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

Note 2 — Mergers, Acquisitions, and Dispositions

Generation recognized a pre-tax gain of \$68 million which is included in Gain on sales of assets and businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on the SolGen nonrecourse debt included as part of the transaction.

Agreement for the Sale of a Generation Biomass Facility (Exelon and Generation)

On April 28, 2021, Generation and ReGenerate Energy Holdings, LLC (“ReGenerate”) entered into a purchase agreement, under which ReGenerate agreed to purchase Generation’s interest in the Albany Green Energy biomass facility. Completion of the transaction is expected in the second half of 2021 and is subject to various customary closing conditions.

As a result, in the second quarter of 2021, Exelon and Generation will reclassify these assets and liabilities as held for sale and expect to record an impairment loss in a range of \$135 million to \$150 million on a pre-tax basis, which will be recorded within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

3. Regulatory Matters (All Registrants)

As discussed in Note 3 — Regulatory Matters of the Exelon 2020 Form 10-K, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The following discusses developments in 2021 and updates to the 2020 Form 10-K.

Utility Regulatory Matters (Exelon, PHI, and the Utility Registrants)

Distribution Base Rate Case Proceedings

The following tables show the completed and pending distribution base rate case proceedings in 2021.

Completed Distribution Base Rate Case Proceedings

Registrant/ Jurisdiction	Filing Date	Service	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois ^(a)	April 16, 2020	Electric	\$ (11)	\$ (14)	8.38 %	December 9, 2020	January 1, 2021
BGE - Maryland ^(b)	May 15, 2020 (amended	Electric	137	81	9.50 %	December 16, 2020	January 1, 2021
	September 11, 2020)	Natural Gas	91	21	9.65 %		

(a) ComEd's 2021 approved revenue requirement reflects an increase of \$50 million for the initial year revenue requirement for 2021 and a decrease of \$64 million related to the annual reconciliation for 2019. The revenue requirement for 2021 and the revenue requirement for 2019 provide for a weighted average debt and equity return on distribution rate base of 6.28%, inclusive of an allowed ROE of 8.38%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points.

(b) Reflects a three-year cumulative multi-year plan for 2021 through 2023. The MDPSC awarded BGE electric revenue requirement increases of \$59 million, \$39 million, and \$42 million in 2021, 2022, and 2023, respectively, and natural gas revenue requirement increases of \$53 million, \$11 million, and \$10 million in 2021, 2022, and 2023, respectively. However, the MDPSC utilized certain tax benefits to fully offset the increases in 2021 so that customer rates will remain unchanged from 2020 to 2021. The MDPSC has deferred a decision on whether to use certain tax benefits to offset the revenue requirement increases in 2022 and 2023 and BGE cannot predict the outcome.

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)	April 16, 2021	Electric	\$ 51	7.36 %	Fourth quarter of 2021
PECO - Pennsylvania	March 30, 2021	Electric	246	10.95 %	Fourth quarter of 2021
PECO - Pennsylvania	September 30, 2020	Natural Gas	69	10.95 %	Second quarter of 2021
Pepco - District of Columbia ^(b)	May 30, 2019 (amended June 1, 2020)	Electric	136	9.7 %	Second quarter of 2021
Pepco - Maryland ^(c)	October 26, 2020 (amended March 31, 2021)	Electric	104	10.2 %	Second quarter of 2021
DPL - Delaware ^(d)	March 6, 2020 (amended February 2, 2021)	Electric	23	10.3 %	Third quarter of 2021
ACE - New Jersey ^(e)	December 9, 2020 (amended February 26, 2021)	Electric	67	10.3 %	Fourth quarter of 2021

- (a) ComEd's 2022 requested revenue requirement reflects an increase of \$40 million for the initial year revenue requirement for 2022 and an increase of \$11 million related to the annual reconciliation for 2020. The revenue requirement for 2022 provides for a weighted average debt and equity return on distribution rate base of 5.72%, inclusive of an allowed ROE of 7.36%, reflecting the average monthly yields for 30-year treasury bonds plus 580 basis points. The reconciliation revenue requirement for 2020 provides for a weighted average debt and equity return on distribution rate base of 5.69%, inclusive of an allowed ROE of 7.29%, reflecting the average monthly yields for 30-year treasury bonds plus 580 basis points less a performance metrics penalty of 7 basis points.
- (b) Pepco filed the multi-year plan enhanced proposal as an alternative to address the impacts of COVID-19. Reflects a three-year cumulative multi-year plan for 2020 through 2022 and requested revenue requirement increases of \$73 million in 2022 and \$63 million in 2023, to recover capital investments made during 2018 through 2020 and planned capital investments through the end of 2022.
- (c) Reflects a three-year cumulative multi-year plan for April 1, 2021 through March 31, 2024 and total requested revenue requirement increases of \$52 million effective April 1, 2023 and \$52 million effective April 1, 2024 to recover capital investments made in 2019 and 2020 and planned capital investments through March 31, 2024.
- (d) The rates went into effect on October 6, 2020, subject to refund.
- (e) Requested increases are before New Jersey sales and use tax. ACE intends to put rates into effect on September 8, 2021 subject to refund.

Transmission Formula Rates

For 2021, the following total increases were included in ComEd's electric transmission formula rate update. PECO, BGE, Pepco, DPL, and ACE intend to file by the required deadline for the annual update.

Registrant ^(a)	Initial Revenue Requirement Increase	Annual Reconciliation Increase	Total Revenue Requirement Increase	Allowed Return on Rate Base ^(b)	Allowed ROE ^(c)
ComEd	\$ 33	\$ 12	\$ 45	8.20 %	11.50 %

- (a) Rates are effective June 30, 2021 - May 31, 2022, subject to review by interested parties pursuant to review protocols of ComEd's tariff.
- (b) Represents the weighted average debt and equity return on transmission rate bases.
- (c) As part of the FERC-approved settlements of ComEd's 2007 rate case, the rate of return on common equity is 11.50%, inclusive of a 50-basis-point incentive adder for being a member of a RTO, and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%.

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

Note 3 — Regulatory Matters

Regulatory Assets and Liabilities

The Utility Registrants' regulatory assets and liabilities have not changed materially since December 31, 2020, unless noted below. See Note 3 — Regulatory Matters of the Exelon 2020 Form 10-K for additional information on the specific regulatory assets and liabilities.

ComEd. Regulatory assets increased \$106 million primarily due to an increase of \$55 million in the Electric Distribution Formula Rate Annual Reconciliations regulatory asset, and \$38 million in the Energy Efficiency Costs regulatory asset.

PECO. Regulatory assets increased \$56 million primarily due to an increase of \$48 million in the Deferred Income Taxes regulatory asset and \$9 million in the Vacation Accrual regulatory asset.

BGE. Regulatory liabilities decreased \$82 million primarily due to a decrease of \$93 million in the Deferred Income Taxes regulatory liability, partially offset by an increase of \$9 million in the Electric Energy and Natural Gas Costs 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 Exelon's and the Utility Registrant's 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.

	Exelon	ComEd ^(a)	PECO	BGE ^(b)	PHI	Pepco ^(c)	DPL ^(c)	ACE
March 31, 2021	\$ 49	\$ —	\$ —	\$ 43	\$ 6	\$ 3	\$ 3	\$ —
December 31, 2020	51	(1)	—	45	7	4	3	—

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

(b) BGE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on its AMI programs.

(c) Pepco's and DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on their respective AMI Programs and Energy Efficiency and Demand Response Programs. The earnings on energy efficiency are on Pepco DC and DPL DE programs only.

Generation Regulatory Matters (Exelon and Generation)

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, Generation's Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. In response to the high demand and significantly reduced total generation on the system, the PUCT directed ERCOT to use an administrative price cap of \$9,000 per MWh during firm load shedding events.

The estimated impact to Exelon's and Generation's Net income for the first quarter of 2021 arising from these market and weather conditions was a reduction of approximately \$880 million. The ultimate impact to Exelon's and Generation's consolidated financial statements for the full year 2021 may be affected by a number of factors, including final settlement data, the impacts of customer and counterparty credit losses, any state or federal solutions to address the financial challenges caused by the event, and related litigation and contract disputes.

During February and March 2021, various parties with differing interests, including generators and retail providers, filed requests with the PUCT to void the PUCT's orders setting prices at \$9,000 per MWh during firm load shedding events. Other requests were made for the PUCT to enforce its order and reduce prices for 32 hours between February 18 and February 19 after firm load shedding ceased and to cap ancillary services at \$9,000 per MWh. Appeals of certain of the PUCT's orders also have been filed in state court. On April 19, 2021, Generation filed a declaratory action and appeal in state court challenging the PUCT's orders setting prices at

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

Note 3 — Regulatory Matters

\$9,000 per MWh. Exelon and Generation cannot predict the outcome of these proceedings or the financial statement impact.

Due to these events, a number of ERCOT market participants experienced bankruptcies, resulting in approximately a \$2.9 billion payment shortfall in collections, which is allocated to the remaining ERCOT market participants. Generation recorded its portion of this obligation of approximately \$28 million on a discounted basis in the first quarter of 2021, which is to be paid over a term of 96 years. Current ERCOT rules limit recovery of default from market participants to \$2.5 million per month market-wide. In February 2021, the PUCT gave ERCOT discretion to disregard its current rules, but ERCOT has declined to exercise that discretion thus far. Generation's request for rehearing of this PUCT order was denied on April 17, 2021 and an appeal is pending in state court. Additionally, several pending legislative proposals were introduced in the Texas legislature during February and March 2021 concerning the amount, timing and allocation of recovery of the \$2.9 billion shortfall. Exelon and Generation are monitoring the proposed legislation and cannot predict the outcome or the financial statement impact.

In addition, several other legislative proposals have been introduced in the Texas legislature during February and March 2021 addressing cold-weather preparation for power plants and natural gas production and transportation infrastructure. The proposed legislation provides the PUCT and the Railroad Commission of Texas with the option of imposing fines if the new proposed standards are not met. Exelon and Generation are monitoring the proposed legislation and cannot predict the outcome. However, such proposed legislation could have a material adverse impact in Exelon's and Generation's consolidated financial statements.

In February 2021, more than 70 local distribution companies (LDCs) in multiple states throughout the mid-continent region, where Generation serves natural gas transportation customers, issued operational flow orders (OFOs), curtailments or other limitations on natural gas use to preserve adequate pressure on the system. When in effect, gas use above these limitations is severely penalized according to the LDCs' tariff. Gas supply in many states became restricted due to wells freezing and pipeline compression disruption, while demand was increasing due to the extreme cold temperatures, resulting in extremely high natural gas prices. Due to the extraordinary circumstances, many LDCs and natural gas pipelines are either voluntarily waiving or seeking regulatory approvals to waive the penalties associated with these restrictions. During March 2021, three natural gas pipelines filed individual petitions with the FERC requesting approval to waive these penalties. Generation also filed motions in March 2021 to intervene with the FERC in support of these requests from the pipelines. On March 25, 2021, the FERC issued an order on one of the petitions approving the request to waive the penalties for February 15, 2021. On April 23, 2021, Generation and several other entities filed a request for rehearing and a complaint to expand the order to include additional days of the weather events in February, from February 15 through February 19, 2021. On April 9, 2021 and April 19, 2021, the FERC issued orders on the remaining petitions approving the requests to waive the penalties. Exelon and Generation cannot predict the outcome of the FERC proceeding or the determinations made by the LDCs.

New Jersey Regulatory Matters

New Jersey Clean Energy Legislation. On May 23, 2018, New Jersey enacted legislation that established a ZEC program that provides compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Under the legislation, the NJBPU will issue ZECs to qualifying nuclear power plants and the electric distribution utilities in New Jersey, including ACE, will be required to purchase those ZECs. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. Upon approval, Generation began recognizing revenue for the sale of New Jersey ZECs in the month they are generated. On March 19, 2021, a three-judge panel of the Superior Court of New Jersey Appellate Division unanimously affirmed the NJBPU's April 2019 order awarding ZECs for the first eligibility period. On April 8, 2021, New Jersey Rate Counsel filed a notice of appeal of the Superior Court's order to the New Jersey Supreme Court. Exelon and Generation cannot predict the outcome of the appeal. On October 1, 2020, PSEG and Generation filed applications seeking ZECs for the second eligibility period (June 2022 through May 2025). On April 27, 2021, the NJBPU approved the award of ZECs to Salem 1 and Salem 2 for the second eligibility period. See Note 7 — Early Plant Retirements for additional information related to Salem.

New England Regulatory Matters

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

Note 3 — Regulatory Matters

Mystic Units 8 & 9 and Everett Marine Terminal Cost of Service Agreement (Exelon and Generation). On March 29, 2018, Generation notified grid operator ISO-NE of its plans to early retire Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. On May 16, 2018, Generation made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 & 9 for the period between June 1, 2022 - May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service compensation, reflecting a number of adjustments to the annual fixed revenue requirement and allowing for recovery of a substantial portion of the costs associated with the adjacent Everett Marine Terminal acquired by Generation in October 2018. Those adjustments were reflected in a compliance filing made on March 1, 2019. In the December 20, 2018 order, FERC also directed a paper hearing on ROE using a new methodology. On January 22, 2019, Exelon and several other parties filed requests for rehearing of certain findings in the order.

On July 17, 2020, FERC issued three orders, which together affirmed the recovery of key elements of Mystic's cost of service compensation, including recovery of costs associated with the operation of the Everett Marine Terminal. FERC directed a downward adjustment to the rate base for Mystic Units 8 and 9, the effect of which will be partially offset by elimination of a crediting mechanism for third party gas sales during the term of the cost of service agreement. In addition, several parties filed protests to a compliance filing by Generation on September 15, 2020, taking issue with how gross plant in-service was calculated, and Generation filed an answer to the protests on October 21, 2020. On December 21, 2020, FERC issued an order on rehearing of the three July 17, 2020 orders, clarifying several cost of service provisions. Several parties appealed the December 21, 2020 order to the U.S. Court of Appeals for the D.C. Circuit and that appeal was consolidated with appeals of orders issued December 20, 2018 and July 17, 2020 in the Mystic proceeding. The briefing schedule for the consolidated appeal has not yet been set.

On February 25, 2021, Mystic made its filing to comply with the December 21, 2020 order. On April 26, 2021, FERC rejected Mystic's language and directed another compliance filing relating to the claw back provision language, which only applies if Mystic 8 and 9 were to continue operation after the conclusion of the cost-of-service period. FERC's April 26, 2021 order also accepted in part and rejected in part Mystic's September 15, 2020 compliance filing. It directed a further compliance filing in 60 days consistent with the information provided in Mystic's October 21, 2020 answer to protests.

On August 25, 2020, a group of New England generators filed a complaint against Generation seeking to extend the scope of the claw back provision in the cost-of-service agreement, whereby Generation would refund certain amounts recovered during the term of the cost of service if it returns to market afterwards. On April 15, 2021 FERC dismissed the complaint.

On February 16, 2021, Generation filed an unopposed motion to voluntarily dismiss an appeal filed with the U.S. Court of Appeals for the D.C. Circuit stemming from a June 2020 complaint filed with the FERC against ISO-NE over failures to follow its tariff in evaluating Mystic for transmission security for the 2024 to 2025 Capacity Commitment Period, which was granted on February 18, 2021.

See Note 7 — Early Plant Retirements for additional information on the impacts of Generation's August 2020 decision to retire Mystic Units 8 & 9 upon expiration of the cost of service agreement.

Federal Regulatory Matters

Operating License Renewals

Conowingo Hydroelectric Project. On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a new license for the Conowingo Hydroelectric Project (Conowingo). In connection with Generation's efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act (401 Certification) from MDE for Conowingo, Generation had been working with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 27, 2018, MDE issued its 401 Certification for Conowingo. On October 29, 2019, Generation and MDE filed with FERC a Joint Offer of Settlement (Offer of Settlement) that would resolve all outstanding issues relating to the 401 Certification. Pursuant to the Offer of Settlement, the parties submitted Proposed License Articles to FERC to be incorporated by FERC into the new license in accordance with FERC's discretionary authority under the Federal Power Act.

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

Note 3 — Regulatory Matters

On March 19, 2021, FERC issued a new 50-year license for Conowingo, effective March 1, 2021. FERC adopted the Proposed License Articles into the new license only making modifications it deemed necessary to allow FERC to enforce the Proposed License Articles. Consistent with the Offer of Settlement, FERC found that MDE waived its 401 Certification.

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. Generation's primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The Utility Registrants' 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 Exelon 2020 Form 10-K for additional information regarding the primary sources of revenue for the Registrants.

Contract Balances (All Registrants)

Contract Assets

Generation records contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before Generation has an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. Generation records contract assets and contract receivables within Other current assets and Customer accounts receivable, net, respectively, within Exelon's and Generation's Consolidated Balance Sheets.

The following table provides a rollforward of the contract assets reflected in Exelon's and Generation's Consolidated Balance Sheets for the three months ended March 31, 2021 and 2020. The Utility Registrants do not have any contract assets.

	Exelon	Generation
Balance as of December 31, 2020	\$ 144	\$ 144
Amounts reclassified to receivables	(16)	(16)
Revenues recognized	13	13
Amounts previously held-for-sale	12	12
Balance as of March 31, 2021	<u>\$ 153</u>	<u>\$ 153</u>
	Exelon	Generation
Balance as of December 31, 2019	\$ 174	\$ 174
Amounts reclassified to receivables	(19)	(19)
Revenues recognized	17	17
Balance as of March 31, 2020	<u>\$ 172</u>	<u>\$ 172</u>

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 within Other current liabilities and Other noncurrent liabilities within the Registrants' Consolidated Balance Sheets.

For Generation, these contract liabilities primarily relate to upfront consideration received or due for equipment service plans, and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation.

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

Note 4 — Revenue from Contracts with Customers

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, Generation's, PHI's, Pepco's, DPL's, and ACE's Consolidated Balance Sheets for the three months ended March 31, 2021 and 2020. As of March 31, 2021 and December 31, 2020, ComEd's, PECO's, and BGE's contract liabilities were immaterial.

	Exelon	Generation	PHI	Pepco	DPL	ACE
Balance as of December 31, 2020	\$ 151	\$ 84	\$ 118	\$ 94	\$ 12	\$ 12
Consideration received or due	20	31	—	—	—	—
Revenues recognized	(27)	(64)	(2)	(2)	—	—
Amounts previously held-for-sale	3	3	—	—	—	—
Balance as of March 31, 2021	\$ 147	\$ 54	\$ 116	\$ 92	\$ 12	\$ 12

	Exelon	Generation	PHI	Pepco	DPL	ACE
Balance as of December 31, 2019	\$ 33	\$ 71	\$ —	\$ —	\$ —	\$ —
Consideration received or due	20	55	—	—	—	—
Revenues recognized	(24)	(70)	—	—	—	—
Balance as of March 31, 2020	\$ 29	\$ 56	\$ —	\$ —	\$ —	\$ —

The following table reflects revenues recognized in the three months ended March 31, 2021 and 2020, which were included in contract liabilities at December 31, 2020 and 2019, respectively:

	Three Months Ended March 31,	
	2021	2020
Exelon	\$ 17	\$ 9
Generation	39	19
PHI	2	—
Pepco	2	—

Transaction Price Allocated to Remaining Performance Obligations (All Registrants)

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, 2021. 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 Generation's power and gas sales contracts as they contain variable volumes and/or variable pricing. This disclosure also 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.

	2021	2022	2023	2024	2025 and thereafter	Total
Exelon	\$ 233	\$ 100	\$ 56	\$ 41	\$ 330	\$ 760
Generation	286	131	56	35	243	751
PHI	7	8	8	6	87	116
Pepco	5	6	6	5	70	92
DPL	1	1	1	—	9	12
ACE	1	1	1	1	8	12

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 (All Registrants)

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 Registrant's revenue disaggregation.

5. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the CODM in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has eleven reportable segments, which include Generation's five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and all other power regions referred to collectively as "Other Power Regions" and 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 ComEd, PECO, BGE, Pepco, DPL, and ACE based on net income.

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of Generation's five reportable segments are as follows:

- **Mid-Atlantic** represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia, and parts of Pennsylvania and North Carolina.
- **Midwest** represents operations in the western half of PJM and the United States footprint of MISO, excluding MISO's Southern Region.
- **New York** represents operations within NYISO.
- **ERCOT** represents operations within Electric Reliability Council of Texas.
- **Other Power Regions:**
 - **New England** represents the operations within ISO-NE.
 - **South** represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM.
 - **West** represents operations in the WECC, which includes California ISO.
 - **Canada** represents operations across the entire country of Canada and includes AESO, OIESO, and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on RNF. Generation believes that RNF is a useful measurement of operational performance. RNF 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. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy, and ancillary services. Fuel expense includes the fuel costs for Generation's owned generation and fuel costs associated with tolling agreements. The results of Generation's other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further,

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

Note 5 — Segment Information

Generation's unrealized mark-to-market gains and losses on economic hedging activities and its amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

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, 2021 and 2020 is as follows:

Three Months Ended March 31, 2021 and 2020

	<u>Generation</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Other^(a)</u>	<u>Intersegment Eliminations</u>	<u>Exelon</u>
Operating revenues^(b):								
2021								
Competitive businesses electric revenues	\$ 4,187	\$ —	\$ —	\$ —	\$ —	\$ —	\$ (293)	\$ 3,894
Competitive businesses natural gas revenues	1,326	—	—	—	—	—	—	1,326
Competitive businesses other revenues	46	—	—	—	—	—	(1)	45
Rate-regulated electric revenues	—	1,535	661	632	1,170	—	(10)	3,988
Rate-regulated natural gas revenues	—	—	228	342	71	—	(4)	637
Shared service and other revenues	—	—	—	—	3	491	(494)	—
Total operating revenues	<u>\$ 5,559</u>	<u>\$ 1,535</u>	<u>\$ 889</u>	<u>\$ 974</u>	<u>\$ 1,244</u>	<u>\$ 491</u>	<u>\$ (802)</u>	<u>\$ 9,890</u>
2020								
Competitive businesses electric revenues	\$ 3,752	\$ —	\$ —	\$ —	\$ —	\$ —	\$ (326)	\$ 3,426
Competitive businesses natural gas revenues	672	—	—	—	—	—	(3)	669
Competitive businesses other revenues	309	—	—	—	—	—	(1)	308
Rate-regulated electric revenues	—	1,439	604	613	1,104	—	(12)	3,748
Rate-regulated natural gas revenues	—	—	209	324	64	—	(2)	595
Shared service and other revenues	—	—	—	—	3	480	(482)	1
Total operating revenues	<u>\$ 4,733</u>	<u>\$ 1,439</u>	<u>\$ 813</u>	<u>\$ 937</u>	<u>\$ 1,171</u>	<u>\$ 480</u>	<u>\$ (826)</u>	<u>\$ 8,747</u>
Intersegment revenues^(c):								
2021	\$ 295	\$ 6	\$ 2	\$ 6	\$ 3	\$ 487	\$ (799)	\$ —
2020	330	5	2	6	3	479	(824)	1

Depreciation and amortization:

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

Note 5 — Segment Information

	Generation	ComEd	PECO	BGE	PHI	Other ^(a)	Intersegment Eliminations	Exelon
2021	\$ 940	\$ 292	\$ 86	\$ 152	\$ 210	\$ 17	\$ —	\$ 1,697
2020	304	273	86	143	194	21	—	1,021
Operating expenses:								
2021	\$ 6,672	\$ 1,210	\$ 679	\$ 752	\$ 1,058	\$ 492	\$ (781)	\$ 10,082
2020	4,400	1,151	625	688	1,000	481	(816)	7,529
Interest expense, net:								
2021	\$ 72	\$ 96	\$ 38	\$ 34	\$ 67	\$ 79	\$ —	\$ 386
2020	109	94	36	32	67	72	—	410
Income (loss) before income taxes:								
2021	\$ (947)	\$ 236	\$ 177	\$ 196	\$ 136	\$ (80)	\$ —	\$ (282)
2020	(547)	204	155	222	119	(69)	1	85
Income Taxes:								
2021	\$ (179)	\$ 39	\$ 10	\$ (13)	\$ 8	\$ 116	\$ —	\$ (19)
2020	(389)	36	15	41	11	(8)	—	(294)
Net income (loss):								
2021	\$ (769)	\$ 197	\$ 167	\$ 209	\$ 128	\$ (196)	\$ —	\$ (264)
2020	(161)	168	140	181	108	(61)	1	376
Capital Expenditures:								
2021	\$ 382	\$ 613	\$ 295	\$ 336	\$ 456	\$ 58	\$ —	\$ 2,140
2020	558	506	259	283	376	34	—	2,016
Total assets:								
March 31, 2021	\$ 47,326	\$34,825	\$12,937	\$11,759	\$24,387	\$ 8,788	\$ (10,022)	\$ 130,000
December 31, 2020	48,094	34,466	12,531	11,650	23,736	9,005	(10,165)	129,317

- (a) Other primarily includes Exelon's corporate operations, shared service entities, and other financing and investment activities.
- (b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 17 — Supplemental Financial Information for additional information on total utility taxes.
- (c) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Related Party Transactions for additional information on intersegment revenues.

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

Note 5 — Segment Information

PHI:

	Pepco	DPL	ACE	Other ^(a)	Intersegment Eliminations	PHI
Operating revenues^(b):						
2021						
Rate-regulated electric revenues	\$ 553	\$ 311	\$ 310	\$ —	\$ (4)	\$ 1,170
Rate-regulated natural gas revenues	—	71	—	—	—	71
Shared service and other revenues	—	—	—	95	(92)	3
Total operating revenues	<u>\$ 553</u>	<u>\$ 382</u>	<u>\$ 310</u>	<u>\$ 95</u>	<u>\$ (96)</u>	<u>\$ 1,244</u>
2020						
Rate-regulated electric revenues	\$ 544	\$ 286	\$ 276	\$ —	\$ (2)	\$ 1,104
Rate-regulated natural gas revenues	—	64	—	—	—	64
Shared service and other revenues	—	—	—	93	(90)	3
Total operating revenues	<u>\$ 544</u>	<u>\$ 350</u>	<u>\$ 276</u>	<u>\$ 93</u>	<u>\$ (92)</u>	<u>\$ 1,171</u>
Intersegment revenues^(c):						
2021	\$ 1	\$ 2	\$ 1	\$ 95	\$ (96)	\$ 3
2020	1	2	1	92	(93)	3
Depreciation and amortization:						
2021	\$ 102	\$ 53	\$ 47	\$ 8	\$ —	\$ 210
2020	95	48	43	9	(1)	194
Operating expenses:						
2021	\$ 466	\$ 309	\$ 282	\$ 97	\$ (96)	\$ 1,058
2020	462	284	251	93	(90)	1,000
Interest expense, net:						
2021	\$ 34	\$ 15	\$ 15	\$ 3	\$ —	\$ 67
2020	34	16	15	3	(1)	67
Income (loss) before income taxes:						
2021	\$ 65	\$ 61	\$ 14	\$ (4)	\$ —	\$ 136
2020 ^(d)	57	52	14	(4)	—	119
Income Taxes:						
2021	\$ 6	\$ 5	\$ —	\$ (3)	\$ —	\$ 8
2020	5	7	1	(2)	—	11
Net income (loss):						
2021	\$ 59	\$ 56	\$ 14	\$ (1)	\$ —	\$ 128
2020	52	45	13	(2)	—	108
Capital Expenditures:						
2021	\$ 220	\$ 112	\$ 123	\$ 1	\$ —	\$ 456
2020	180	95	101	—	—	376
Total assets:						
March 31, 2021	\$ 9,493	\$ 5,232	\$ 4,679	\$ 5,020	\$ (37)	\$ 24,387
December 31, 2020	9,264	5,140	4,286	5,079	(33)	23,736

- (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 17 — Supplemental Financial Information for additional information on total utility taxes.
- (c) Includes intersegment revenues with ComEd, BGE, and PECO, which are eliminated at Exelon.
- (d) The Income (loss) before income taxes in Other and Intersegment Eliminations have been adjusted by an offsetting \$110 million in 2020.

The following tables disaggregate the Registrants' 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. For Generation, the disaggregation of revenues reflects Generation's two primary products of

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

Note 5 — Segment Information

power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of rate-regulated electric sales and rate-regulated natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with Generation and the Utility Registrants, but exclude any intercompany revenues.

Competitive Business Revenues (Generation):

	Three Months Ended March 31, 2021				
	Revenues from external customers ^(a)			Intersegment Revenues	Total Revenues
	Contracts with customers	Other ^(b)	Total		
Mid-Atlantic	\$ 1,174	\$ (14)	\$ 1,160	\$ 5	\$ 1,165
Midwest	1,009	(11)	998	—	998
New York	382	(45)	337	—	337
ERCOT	353	(101)	252	5	257
Other Power Regions	1,172	268	1,440	(10)	1,430
Total Competitive Businesses Electric Revenues	4,090	97	4,187	—	4,187
Competitive Businesses Natural Gas Revenues	864	462	1,326	—	1,326
Competitive Businesses Other Revenues ^(c)	89	(43)	46	—	46
Total Generation Consolidated Operating Revenues	<u>\$ 5,043</u>	<u>\$ 516</u>	<u>\$ 5,559</u>	<u>\$ —</u>	<u>\$ 5,559</u>

	Three Months Ended March 31, 2020				
	Revenues from external customers ^(a)			Intersegment revenues	Total Revenues
	Contracts with customers	Other ^(b)	Total		
Mid-Atlantic	\$ 1,264	\$ (96)	\$ 1,168	\$ 6	\$ 1,174
Midwest	944	64	1,008	(6)	1,002
New York	335	(21)	314	—	314
ERCOT	155	28	183	7	190
Other Power Regions	1,007	72	1,079	(7)	1,072
Total Competitive Businesses Electric Revenues	3,705	47	3,752	—	3,752
Competitive Businesses Natural Gas Revenues	503	169	672	—	672
Competitive Businesses Other Revenues ^(c)	99	210	309	—	309
Total Generation Consolidated Operating Revenues	<u>\$ 4,307</u>	<u>\$ 426</u>	<u>\$ 4,733</u>	<u>\$ —</u>	<u>\$ 4,733</u>

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.

(b) Includes revenues from derivatives and leases.

(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market losses of \$84 million and gains of \$179 million in 2021 and 2020, respectively, and elimination of intersegment revenues.

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

Note 5 — Segment Information

Revenues net of purchased power and fuel expense (Generation):

	Three Months Ended March 31, 2021			Three Months Ended March 31, 2020		
	RNF from external customers ^(a)	Intersegment RNF	Total RNF	RNF from external customers ^(a)	Intersegment RNF	Total RNF
Mid-Atlantic	\$ 562	\$ 5	\$ 567	\$ 559	\$ 8	\$ 567
Midwest	702	—	702	732	(5)	727
New York	240	2	242	189	4	193
ERCOT	(1,036)	(148)	(1,184)	76	4	80
Other Power Regions	250	(33)	217	177	(19)	158
Total Revenues net of purchased power and fuel expense for Reportable Segments	718	(174)	544	1,733	(8)	1,725
Other ^(b)	231	174	405	296	8	304
Total Generation Revenues net of purchased power and fuel expense	<u>\$ 949</u>	<u>\$ —</u>	<u>\$ 949</u>	<u>\$ 2,029</u>	<u>\$ —</u>	<u>\$ 2,029</u>

(a) Includes purchases and sales from/to third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Primarily includes:

- unrealized mark-to-market gains of \$175 million and gains of \$132 million in 2021 and 2020, respectively;
- accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 7 - Early Plant Retirements of \$54 million in 2021; and
- the elimination of intersegment RNF.

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

Note 5 — Segment Information

Electric and Gas Revenue by Customer Class (Utility Registrants):

Revenues from contracts with customers	Three Months Ended March 31, 2021						
	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	\$ 741	\$ 433	\$ 362	\$ 605	\$ 253	\$ 190	\$ 162
Small commercial & industrial	367	100	69	118	33	46	39
Large commercial & industrial	134	57	105	248	184	21	43
Public authorities & electric railroads	11	9	7	13	6	4	3
Other ^(a)	220	52	77	143	51	41	52
Total rate-regulated electric revenues^(b)	\$ 1,473	\$ 651	\$ 620	\$ 1,127	\$ 527	\$ 302	\$ 299
Rate-regulated natural gas revenues							
Residential	\$ —	\$ 160	\$ 216	\$ 46	\$ —	\$ 46	\$ —
Small commercial & industrial	—	59	35	18	—	18	—
Large commercial & industrial	—	—	54	2	—	2	—
Transportation	—	7	—	4	—	4	—
Other ^(c)	—	2	31	1	—	1	—
Total rate-regulated natural gas revenues^(d)	\$ —	\$ 228	\$ 336	\$ 71	\$ —	\$ 71	\$ —
Total rate-regulated revenues from contracts with customers	\$ 1,473	\$ 879	\$ 956	\$ 1,198	\$ 527	\$ 373	\$ 299
Other revenues							
Revenues from alternative revenue programs	\$ 54	\$ 10	\$ 18	\$ 46	\$ 26	\$ 9	\$ 11
Other rate-regulated electric revenues ^(e)	8	—	—	—	—	—	—
Other rate-regulated natural gas revenues ^(e)	—	—	—	—	—	—	—
Total other revenues	\$ 62	\$ 10	\$ 18	\$ 46	\$ 26	\$ 9	\$ 11
Total rate-regulated revenues for reportable segments	\$ 1,535	\$ 889	\$ 974	\$ 1,244	\$ 553	\$ 382	\$ 310

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, 2020						
	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	\$ 701	\$ 382	\$ 339	\$ 534	\$ 236	\$ 161	\$ 137
Small commercial & industrial	362	99	67	115	35	43	37
Large commercial & industrial	134	53	103	253	188	23	42
Public authorities & electric railroads	13	7	7	15	9	3	3
Other ^(a)	211	58	79	169	60	54	55
Total rate-regulated electric revenues^(b)	\$ 1,421	\$ 599	\$ 595	\$ 1,086	\$ 528	\$ 284	\$ 274
Rate-regulated natural gas revenues							
Residential	\$ —	\$ 150	\$ 206	\$ 40	\$ —	\$ 40	\$ —
Small commercial & industrial	—	51	34	17	—	17	—
Large commercial & industrial	—	—	51	1	—	1	—
Transportation	—	6	—	4	—	4	—
Other ^(c)	—	1	9	2	—	2	—
Total rate-regulated natural gas revenues^(d)	\$ —	\$ 208	\$ 300	\$ 64	\$ —	\$ 64	\$ —
Total rate-regulated revenues from contracts with customers	\$ 1,421	\$ 807	\$ 895	\$ 1,150	\$ 528	\$ 348	\$ 274
Other revenues							
Revenues from alternative revenue programs	\$ 12	\$ 2	\$ 36	\$ 18	\$ 15	\$ 1	\$ 1
Other rate-regulated electric revenues ^(e)	6	3	3	3	1	1	1
Other rate-regulated natural gas revenues ^(e)	—	1	3	—	—	—	—
Total other revenues	\$ 18	\$ 6	\$ 42	\$ 21	\$ 16	\$ 2	\$ 2
Total rate-regulated revenues for reportable segments	\$ 1,439	\$ 813	\$ 937	\$ 1,171	\$ 544	\$ 350	\$ 276

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

(b) Includes operating revenues from affiliates in 2021 and 2020 respectively of:

- \$6 million, \$5 million at ComEd
- \$1 million, \$2 million at PECO
- \$2 million, \$6 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 2021 and 2020 respectively of:

- less than \$1 million at PECO for both 2021 and 2020
- \$4 million, \$3 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 (All Registrants)

The following tables present the rollforward of Allowance for Credit Losses on Customer Accounts Receivable.

	Three Months Ended March 31, 2021								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2020	\$ 366	\$ 32	\$ 97	\$ 116	\$ 35	\$ 86	\$ 32	\$ 22	\$ 32
Plus: Current period provision for expected credit losses ^(a)	104	34	21	20	9	20	11	6	3
Less: Write-offs, net of recoveries ^(b)	28	1	15	6	1	5	2	3	—
Balance as of March 31, 2021	<u>\$ 442</u>	<u>\$ 65</u>	<u>\$ 103</u>	<u>\$ 130</u>	<u>\$ 43</u>	<u>\$ 101</u>	<u>\$ 41</u>	<u>\$ 25</u>	<u>\$ 35</u>

	Three Months Ended March 31, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2019	\$ 243	\$ 80	\$ 59	\$ 55	\$ 12	\$ 37	\$ 13	\$ 11	\$ 13
Plus: Current period provision for expected credit losses	55	4	18	18	8	7	3	2	2
Less: Write-offs, net of recoveries ^(b)	20	3	6	7	2	2	1	—	1
Balance as of March 31, 2020	<u>\$ 278</u>	<u>\$ 81</u>	<u>\$ 71</u>	<u>\$ 66</u>	<u>\$ 18</u>	<u>\$ 42</u>	<u>\$ 15</u>	<u>\$ 13</u>	<u>\$ 14</u>

- (a) For Generation, primarily relates to the impacts of the February 2021 extreme cold weather event. See Note 3 — Regulatory Matters for additional information. For the Utility Registrants, the increase is primarily as a result of increased receivable balances due to the colder weather and the increased aging of receivables, the temporary suspension of customer disconnections for non-payment, temporary cessation of new late payment fees, and reconnection of service to customers previously disconnected due to COVID-19.
- (b) 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

The following tables present the rollforward of Allowance for Credit Losses on Other Accounts Receivable.

	Three Months Ended March 31, 2021								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2020	\$ 71	\$ —	\$ 21	\$ 8	\$ 9	\$ 33	\$ 13	\$ 9	\$ 11
Plus: Current period provision for expected credit losses	10	—	1	4	1	4	2	1	1
Less: Write-offs, net of recoveries ^(a)	2	—	—	1	1	—	—	—	—
Balance as of March 31, 2021	<u>\$ 79</u>	<u>\$ —</u>	<u>\$ 22</u>	<u>\$ 11</u>	<u>\$ 9</u>	<u>\$ 37</u>	<u>\$ 15</u>	<u>\$ 10</u>	<u>\$ 12</u>

	Three Months Ended March 31, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2019	\$ 48	\$ —	\$ 20	\$ 7	\$ 5	\$ 16	\$ 7	\$ 4	\$ 5
Plus: Current period provision for expected credit losses	8	—	3	1	2	2	1	—	1
Less: Write-offs, net of recoveries ^(a)	4	—	1	1	2	—	—	—	—
Balance as of March 31, 2020	<u>\$ 52</u>	<u>\$ —</u>	<u>\$ 22</u>	<u>\$ 7</u>	<u>\$ 5</u>	<u>\$ 18</u>	<u>\$ 8</u>	<u>\$ 4</u>	<u>\$ 6</u>

(a) Recoveries were not material to the Registrants.

Unbilled Customer Revenue (All Registrants)

The following table provides additional information about unbilled customer revenues recorded in the Registrants' Consolidated Balance Sheets as of March 31, 2021 and December 31, 2020.

	Unbilled customer revenues ^(a)								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
March 31, 2021	\$ 1,178	\$ 671	\$ 161	\$ 102	\$ 126	\$ 118	\$ 58	\$ 38	\$ 22
December 31, 2020	998	258	218	147	197	178	87	62	29

(a) Unbilled customer revenues are classified in Customer accounts receivables, net in the Registrants' Consolidated Balance Sheets.

Sales of Customer Accounts Receivable (Exelon and Generation)

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly-owned by Generation, entered into a revolving accounts receivable financing arrangement with a number of financial institutions and a commercial paper conduit (the Purchasers) to sell certain customer accounts receivable (the Facility). The Facility had a maximum funding limit of \$750 million and was scheduled to expire on April 7, 2021, unless renewed by the mutual consent of the parties in accordance with its terms. The Facility was renewed on March 29, 2021. The Facility term was extended through March 29, 2024, unless further renewed by the mutual consent of the parties, and the maximum funding limit was increased to \$900 million. Under the Facility, NER may sell eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers are reported as sales of receivables in Exelon's and Generation's consolidated financial statements. The subordinated interest in collections upon the receivables sold to the Purchasers is referred to as the DPP, which is reflected in Other current assets on Exelon's and Generation's Consolidated Balance Sheets.

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

Note 6 — Accounts Receivable

On April 8, 2020, Generation derecognized and transferred approximately \$1.2 billion of receivables at fair value to the Purchasers in exchange for approximately \$500 million in cash purchase price and \$650 million of DPP.

On February 17, 2021, Generation received additional cash of \$250 million from the Purchasers for the remaining available funding in the Facility.

On March 31, 2021, Generation received cash of approximately \$150 million from the Purchasers in connection with the increased funding limit at the time of the Facility renewal.

The following table summarizes the impact of the sale of certain receivables:

	March 31, 2021	December 31, 2020
Derecognized receivables transferred at fair value	\$ 1,301	\$ 1,139
Cash proceeds received	900	500
DPP	401	639
	Three Months Ended March 31, 2021	
Loss on sale of receivables ^(a)	\$	17

(a) Reflected in Operating and maintenance expense on Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

	Three Months Ended March 31, 2021
Proceeds from new transfers ^(a)	\$ 1,036
Cash collections received on DPP and reinvested in the Facility ^(b)	1,174
Cash collections reinvested in the Facility	2,210

(a) Customer accounts receivable sold into the Facility were \$2,375 million for the three months ended March 31, 2021.

(b) Does not include the \$400 million in cash proceeds received from the Purchasers in the first quarter of 2021.

Generation's risk of loss following the transfer of accounts receivable is limited to the DPP outstanding. Payment of DPP is not subject to significant risks other than delinquencies and credit losses on accounts receivable transferred, which have historically been and are expected to be immaterial. Generation continues to service the receivables sold in exchange for a servicing fee. Generation did not record a servicing asset or liability as the servicing fees were immaterial.

Generation recognizes the cash proceeds received upon sale in Net cash provided by operating activities in the Consolidated Statement of Cash Flows. The collection and reinvestment of DPP is recognized in Net cash provided by investing activities of the Consolidated Statement of Cash Flows.

See Note 13 — Fair Value of Financial Assets and Liabilities and Note 16 — Variable Interest Entities for additional information.

Other Purchases and Sales of Customer and Other Accounts Receivables (All Registrants)

Generation is required, under supplier tariffs in ISO-NE, MISO, NYISO, and PJM, to sell customer and other receivables to utility companies, which include the Utility Registrants. The Utility Registrants are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia, 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 tables present the total receivables purchased and sold.

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

Note 6 — Accounts Receivable

	Three Months Ended March 31, 2021								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Total receivables purchased	\$ 1,011	\$ —	\$ 266	\$ 290	\$ 199	\$ 268	\$ 166	\$ 56	\$ 46
Total receivables sold	69	81	—	—	—	—	—	—	—
Related party transactions:									
Receivables purchased from Generation	—	—	—	—	12	—	—	—	—
Receivables sold to the Utility Registrants	—	12	—	—	—	—	—	—	—
	Three Months Ended March 31, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Total receivables purchased	\$ 781	\$ —	\$ 280	\$ 284	\$ 195	\$ 264	\$ 165	\$ 53	\$ 46
Total receivables sold	507	749	—	—	—	—	—	—	—
Related party transactions:									
Receivables purchased from Generation	—	—	34	67	69	72	51	13	8
Receivables sold to the Utility Registrants	—	242	—	—	—	—	—	—	—

7. Early Plant Retirements (Exelon and Generation)

Exelon and Generation continuously evaluate factors that affect the current and expected economic value of Generation’s plants, including, but not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure plants are fairly compensated for benefits they provide through their carbon-free emissions, reliability, or fuel security, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any plant, and the resulting financial statement impacts, may be affected by many factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and NDT fund requirements for nuclear plants, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

Nuclear Generation

In 2015 and 2016, Generation identified the Clinton and Quad Cities nuclear plants in Illinois, Ginna and Nine Mile Point nuclear plants in New York, and TMI nuclear plant in Pennsylvania as having the greatest risk of early retirement based on economic valuation and other factors. In 2017, PSEG made public similar financial challenges facing its New Jersey nuclear plants, including Salem, of which Generation owns a 42.59% ownership interest. PSEG is the operator of Salem and also has the decision-making authority to retire Salem.

Assuming the continued effectiveness of the Illinois ZES, New Jersey ZEC program, and the New York CES, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Salem, Ginna, or Nine Mile Point to be at heightened risk for early retirement. However, to the extent the Illinois ZES, New Jersey ZEC program, or the New York CES do not operate as expected over their full terms, each of these plants, in addition to FitzPatrick, would be at heightened risk for early retirement, which could have a material impact on Exelon’s and Generation’s future financial statements. In addition, FERC’s December 19, 2019 order on the MOPR in PJM may undermine the continued effectiveness of the Illinois ZES and the New

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

Note 7 — Early Plant Retirements

Jersey ZEC program unless Illinois and New Jersey implement an FRR mechanism under which the Generation plants in these states would be removed from PJM's capacity auction. See Note 3 — Regulatory Matters for additional information on the New Jersey ZEC program and Note 3 — Regulatory Matters of the 2020 Form 10-K for additional information on the Illinois ZES, New York CES, and FERC's December 19, 2019 order on the MOPR in PJM.

Generation's Dresden, Byron, and Braidwood nuclear plants in Illinois are also showing increased signs of economic distress, in a market that does not currently compensate them for their unique contribution to grid resiliency and their ability to produce large amounts of energy without carbon and air pollution. The May 2018 PJM capacity auction for the 2021-2022 planning year resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood. While all of LaSalle's capacity did clear in the 2021-2022 planning year auction, Generation has become increasingly concerned about the economic viability of this plant as well in a landscape where energy market prices remain depressed and energy market rules remain fatally flawed.

On August 27, 2020, Generation announced that it intends to permanently cease generation operations at Byron in September 2021 and at Dresden in November 2021. The current NRC licenses for Byron Units 1 and 2 expire in 2044 and 2046, respectively, and the licenses for Dresden Units 2 and 3 expire in 2029 and 2031, respectively.

As a result of the decision to early retire Byron and Dresden, Exelon and Generation recognized certain one-time charges in the third and fourth quarters of 2020 related to materials and supplies inventory reserve adjustments, employee-related costs including severance benefit costs further discussed below, and construction work-in-progress impairments, among other items. In addition, as a result of the decisions to early retire Byron and Dresden, there are ongoing annual financial impacts stemming from shortening the expected economic useful lives of these nuclear plants primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and changes in ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date. The total impact for the three months ended March 31, 2021 on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income is summarized in the table below.

Income statement expense (pre-tax)	Three Months Ended March 31, 2021 ^(a)
Depreciation and amortization	
Accelerated depreciation ^(a)	\$ 620
Accelerated nuclear fuel amortization	54
Operating and maintenance	
Other charges	2
Contractual offset ^(b)	(226)
Total	\$ 450

(a) Includes the accelerated depreciation of plant assets including any ARC.

(b) Reflects contractual offset for ARO accretion and ARC depreciation. Based on the regulatory agreement with the ICC, decommissioning-related activities in the first quarter of 2021 have been offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset in 2021 resulted in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. See Note 10 - Asset Retirement Obligations of the Exelon 2020 Form 10-K for additional information.

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

Note 7 — Early Plant Retirements

Severance benefit costs will be provided to employees impacted by the early retirements of Byron and Dresden, to the extent they are not redeployed to other nuclear plants. In 2020, Exelon and Generation recorded estimated severance expense of \$81 million within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income. The severance liability was \$81 million as of March 31, 2021 on Exelon's and Generation's Consolidated Balance Sheets. The final amount of severance benefit costs will depend on the specific employees severed.

The following table provides the balance sheet amounts as of March 31, 2021 for Exelon's and Generation's significant assets and liabilities associated with the Braidwood and LaSalle nuclear plants. Current depreciation provisions are based on the estimated useful lives of these nuclear generating stations, which reflect the first renewal of the operating licenses.

	Braidwood	LaSalle	Total
Asset Balances			
Materials and supplies inventory, net	\$ 83	\$ 103	\$ 186
Nuclear fuel inventory, net	165	264	429
Completed plant, net	1,379	1,566	2,945
Construction work in progress	33	70	103
Liability Balances			
Asset retirement obligation	(577)	(964)	(1,541)
NRC License First Renewal Term	2046 (Unit 1)	2042 (Unit 1)	
	2047 (Unit 2)	2043 (Unit 2)	

Exelon continues to work with stakeholders on state policy solutions, while also advocating for broader market reforms at the regional and federal level. The absence of such solutions or reforms could result in future impairments of the Midwest asset group, or accelerated depreciation for specific plants over their shortened estimated useful lives, both of which could have a material unfavorable impact on Exelon's and Generation's future results of operations.

Other Generation

In March 2018, Generation notified ISO-NE of its plans to early retire, among other assets, the Mystic Generating Station's units 8 and 9 (Mystic 8 and 9) absent regulatory reforms to properly value reliability and regional fuel security. Thereafter, ISO-NE identified Mystic 8 and 9 as being needed to ensure fuel security for the region and entered into a cost of service agreement with these two units for the period between June 1, 2022 - May 31, 2024. The agreement was approved by the FERC in December 2018.

On June 10, 2020, Generation filed a complaint with FERC against ISO-NE stating that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic 8 and 9 for transmission security for the 2024 to 2025 Capacity Commitment Period and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic 8 and 9 should have been filed with FERC for approval. On August 17, 2020, FERC issued an order denying the complaint. As a result, on August 20, 2020, Exelon determined that Generation will permanently cease generation operations at Mystic 8 and 9 at the expiration of the cost of service commitment in May 2024. See Note 3 — Regulatory Matters for additional discussion of Mystic's cost of service agreement.

As a result of the decision to early retire Mystic 8 and 9, there are financial impacts stemming from shortening the expected economic useful life of Mystic 8 and 9 primarily related to accelerated depreciation of plant assets. Exelon and Generation recorded incremental Depreciation and amortization expense of \$20 million for the three months ended March 31, 2021.

8. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for

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

Note 8 — Nuclear Decommissioning

financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models, and discount rates. Generation updates its ARO annually, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The financial statement impact for changes in the ARO, on an individual unit basis, due to the changes in and timing of estimated cash flows generally result in a corresponding change in the unit's ARC within Property, plant, and equipment on Exelon's and Generation's Consolidated Balance Sheets. If the ARO decreases for a Non-Regulatory Agreement unit without any remaining ARC, the corresponding change is recorded as decrease in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The following table provides a rollforward of the nuclear decommissioning ARO reflected in Exelon's and Generation's Consolidated Balance Sheets from December 31, 2020 to March 31, 2021:

Nuclear decommissioning ARO at December 31, 2020 ^(a)	\$	11,922
Accretion expense		124
Costs incurred related to decommissioning plants		(20)
Nuclear decommissioning ARO at March 31, 2021 ^(a)	\$	<u>12,026</u>

(a) Includes \$80 million as the current portion of the ARO at March 31, 2021 and December 31, 2020, which is included in Other current liabilities in Exelon's and Generation's Consolidated Balance Sheets.

NDT Funds

Exelon and Generation had NDT funds totaling \$14,927 million and \$14,599 million at March 31, 2021 and December 31, 2020, respectively. The NDT funds also include \$239 million and \$134 million for the current portion of the NDT funds at March 31, 2021 and December 31, 2020, respectively, which are included in Other current assets in Exelon's and Generation's Consolidated Balance Sheets. See Note 17 — Supplemental Financial Information for additional information on activities of the NDT funds.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life.

Generation filed its biennial decommissioning funding status report with the NRC on February 24, 2021 for all units, including its shutdown units, except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions, LLC. The status report demonstrated adequate decommissioning funding assurance as of December 31, 2020 for all units except for Byron Units 1 and 2. Generation stated that it intends to submit its PSDAR with additional decommissioning cost information by July 1, 2021, for Byron Units 1 and 2, and will evaluate the status of funding assurance based on the updated cost information and provide additional funding assurance by the time of shutdown if required.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2022. This report will reflect the status of decommissioning funding assurance as of December 31, 2021 for shutdown units.

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

Note 9 — Income Taxes

9. 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, 2021									
	Exelon^(a)	Generation^(a)	ComEd^(b)	PECO^(b)	BGE^{(b),(c)}	PHI^(b)	Pepco^(b)	DPL^(b)	ACE^(b)
U.S. Federal statutory rate	21.0%	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	14.6	4.4	6.8	(1.6)	(10.1)	6.1	5.5	6.4	6.9
Qualified NDT fund income	(18.4)	(5.5)	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	2.4	0.6	(0.1)	—	(0.1)	(0.1)	—	(0.2)	(0.2)
Plant basis differences	8.8	—	(0.6)	(10.5)	(1.4)	(1.5)	(2.1)	(0.7)	(0.9)
Production tax credits and other credits	6.7	1.8	(0.2)	—	(0.4)	(0.2)	(0.2)	(0.1)	(0.3)
Noncontrolling interests	0.6	0.2	—	—	—	—	—	—	—
Excess deferred tax amortization	27.9	—	(6.9)	(3.2)	(15.5)	(19.3)	(15.1)	(18.5)	(28.7)
Other ^(d)	(56.9)	(3.6)	(3.5)	(0.1)	(0.1)	(0.1)	0.1	0.3	2.2
Effective income tax rate	6.7%	18.9%	16.5%	5.6%	(6.6)%	5.9%	9.2%	8.2%	—%

Three Months Ended March 31, 2020									
	Exelon^(b)	Generation^(e)	ComEd^(b)	PECO^(b)	BGE^(b)	PHI^(b)	Pepco^(b)	DPL^(b)	ACE^(b)
U.S. Federal statutory rate	21.0%	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	34.0	0.7	8.3	0.1	5.7	5.8	4.7	6.6	6.7
Qualified NDT fund income	(235.8)	36.4	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(4.5)	0.5	(0.2)	—	(0.1)	(0.1)	—	(0.2)	(0.2)
Plant basis differences	(23.0)	—	(1.1)	(8.4)	(1.2)	(1.4)	(2.1)	(0.7)	(0.8)
Production tax credits and other credits	(9.9)	1.3	(0.2)	—	(0.2)	—	—	—	—
Noncontrolling interests	10.6	(1.6)	—	—	—	—	—	—	—
Excess deferred tax amortization	(71.7)	—	(10.5)	(3.0)	(7.3)	(15.5)	(14.2)	(12.7)	(18.8)
Tax Settlements	(79.1)	12.2	—	—	—	—	—	—	—
Other	12.5	0.6	0.3	—	0.6	(0.6)	(0.6)	(0.5)	(0.8)
Effective income tax rate	(345.9)%	71.1%	17.6%	9.7%	18.5%	9.2%	8.8%	13.5%	7.1%

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

Note 9 — Income Taxes

- (a) Exelon and Generation recognized a loss before income taxes for the quarter ended March 31, 2021. As a result, positive percentages represent an income tax benefit for the period presented.
- (b) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
- (c) For BGE, the income tax benefit is primarily due to the Maryland multi-year plan which resulted in the acceleration of certain income tax benefits.
- (d) For Exelon, "Other" is primarily driven by the consolidating income tax adjustment recorded at Exelon Corporate in the first quarter of 2021 that was required pursuant to GAAP interim reporting guidance. This incremental expense will reverse by year-end and will not have an impact on annual results.
- (e) Generation recognized a loss before income taxes for the quarter ended March 31, 2020. As a result, positive percentages represent an income tax benefit for the period presented.

Unrecognized Tax Benefits

PHI and ACE have the following unrecognized tax benefits as of March 31, 2021 and December 31, 2020. Exelon's, Generation's, ComEd's, PECO's, BGE's, Pepco's, and DPL's amounts are not material.

	PHI	ACE
March 31, 2021	\$ 52	\$ 15
December 31, 2020	52	15

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, 2021, ACE has approximately \$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.

10. Retirement Benefits (All Registrants)

Defined Benefit Pension and OPEB

During the first quarter of 2021, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2021. This valuation resulted in an increase to the pension obligations of \$33 million and a decrease to the OPEB obligations of \$9 million. Additionally, accumulated other comprehensive loss increased by \$1 million (after-tax) and regulatory assets and liabilities increased by \$21 million and \$1 million, respectively.

The majority of the 2021 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 2.58%. The majority of the 2021 OPEB cost is calculated using an expected long-term rate of return on plan assets of 6.46% for funded plans and a discount rate of 2.51%.

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, 2021 and 2020.

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

Note 10 — Retirement Benefits

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2021	2020	2021	2020
Components of net periodic benefit cost:				
Service cost	\$ 110	\$ 97	\$ 21	\$ 23
Interest cost	161	189	28	38
Expected return on assets	(336)	(318)	(40)	(41)
Amortization of:				
Prior service cost (credit)	1	1	(8)	(31)
Actuarial loss	150	128	9	12
Curtailment benefits	—	—	(1)	—
Net periodic benefit cost	\$ 86	\$ 97	\$ 9	\$ 1

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 Generation and the Utility Registrants, 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.

Pension and OPEB Costs	Three Months Ended March 31,	
	2021	2020
Exelon	\$ 95	\$ 98
Generation	26	27
ComEd	32	28
PECO	2	1
BGE	15	16
PHI	12	17
Pepco	2	3
DPL	1	1
ACE	3	3

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow 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 matching contributions to the savings plans for the three months ended March 31, 2021 and 2020, respectively.

Savings Plans Matching Contributions	Three Months Ended March 31,	
	2021	2020
Exelon	\$ 33	\$ 33
Generation	13	13
ComEd	8	7
PECO	3	3
BGE	2	2
PHI	3	3
Pepco	1	1
DPL	1	1

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

Note 11 — Derivative Financial Instruments

11. Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, interest rate risk, and foreign exchange risk related to ongoing business operations.

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. All derivative economic hedges related to commodities, referred to as economic hedges, are recorded at fair value through earnings at Generation and are offset by a corresponding regulatory asset or liability at ComEd. 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.

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referenced contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. In the tables below, which present fair value balances, Generation's energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting columns.

Generation's and ComEd's use of cash collateral is generally unrestricted unless Generation or ComEd are 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 meet certain qualifications.

Commodity Price Risk (All Registrants)

Each of 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, including swaps, futures, forwards, options, and short-term and long-term commitments to purchase and sell energy and commodity products. The Registrants believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

Generation. To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels, and other commodities. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. To manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities and are subject to limits established by Exelon's RMC.

Utility Registrants. 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'

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

Note 11 — Derivative Financial Instruments

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.
		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 2020 Form 10-K for additional information.

(b) The fair value of the DPL economic hedge is not material as of March 31, 2021 and December 31, 2020 and is not presented in the fair value tables below.

The following table provides a summary of the derivative fair value balances recorded by Exelon, Generation, and ComEd as of March 31, 2021 and December 31, 2020:

	Exelon		Generation				ComEd	
	Total Derivatives	Economic Hedges	Proprietary Trading	Collateral ^{(a)(b)}	Netting ^(a)	Subtotal	Economic Hedges	
March 31, 2021								
Mark-to-market derivative assets (current assets)	\$ 569	\$ 2,566	\$ 28	\$ 24	\$(2,049)	\$ 569	\$ —	
Mark-to-market derivative assets (noncurrent assets)	488	1,400	5	45	(962)	488	—	
Total mark-to-market derivative assets	1,057	3,966	33	69	(3,011)	1,057	—	
Mark-to-market derivative liabilities (current liabilities)	(418)	(2,472)	(13)	49	2,049	(387)	(31)	
Mark-to-market derivative liabilities (noncurrent liabilities)	(454)	(1,179)	(1)	28	962	(190)	(264)	
Total mark-to-market derivative liabilities	(872)	(3,651)	(14)	77	3,011	(577)	(295)	
Total mark-to-market derivative net assets (liabilities)	\$ 185	\$ 315	\$ 19	\$ 146	\$ —	\$ 480	\$ (295)	

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

Note 11 — Derivative Financial Instruments

December 31, 2020	Exelon			Generation			ComEd
	Total Derivatives	Economic Hedges	Proprietary Trading	Collateral ^{(a)(b)}	Netting ^(a)	Subtotal	Economic Hedges
Mark-to-market derivative assets (current assets)	\$ 639	\$ 2,757	\$ 40	\$ 103	\$(2,261)	\$ 639	\$ —
Mark-to-market derivative assets (noncurrent assets)	554	1,501	4	64	(1,015)	554	—
Total mark-to-market derivative assets	1,193	4,258	44	167	(3,276)	1,193	—
Mark-to-market derivative liabilities (current liabilities)	(293)	(2,629)	(23)	131	2,261	(260)	(33)
Mark-to-market derivative liabilities (noncurrent liabilities)	(472)	(1,335)	(2)	118	1,015	(204)	(268)
Total mark-to-market derivative liabilities	(765)	(3,964)	(25)	249	3,276	(464)	(301)
Total mark-to-market derivative net assets (liabilities)	\$ 428	\$ 294	\$ 19	\$ 416	\$ —	\$ 729	\$ (301)

- (a) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance in the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit, and other forms of non-cash collateral. These amounts are not material and not reflected in the table above.
- (b) Of the collateral posted, \$148 million and \$209 million represents variation margin on the exchanges as of March 31, 2021 and December 31, 2020 respectively.

Economic Hedges (Commodity Price Risk)

Generation. For the three months ended March 31, 2021 and 2020, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

Income Statement Location	Three Months Ended March 31,	
	2021	2020
	Gain (Loss)	
Operating revenues	\$ (83)	\$ 175
Purchased power and fuel	265	(47)
Total Exelon and Generation	\$ 182	\$ 128

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of March 31, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% for 2021.

Proprietary Trading (Commodity Price Risk)

Generation also executes commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows. For the three months ended March 31, 2021 and 2020, net pre-tax commodity mark-to-market gains and losses for Exelon and Generation were not material. The Utility Registrants do not execute derivatives for proprietary trading purposes.

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

Note 11 — Derivative Financial Instruments

Interest Rate and Foreign Exchange Risk (Exelon and Generation)

Generation utilizes interest rate swaps to manage its interest rate exposure and foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, both of which are treated as economic hedges. The notional amounts were \$563 million and \$665 million for Exelon and Generation as of March 31, 2021 and December 31, 2020, respectively.

The mark-to-market derivative assets and liabilities as of March 31, 2021 and December 31, 2020 and the mark-to-market gains and losses for the three months ended March 31, 2021 and 2020 were not material for Exelon and Generation.

Credit Risk (All Registrants)

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.

Generation. For commodity derivatives, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds, and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

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

Note 11 — Derivative Financial Instruments

The following tables provide information on Generation’s credit exposure for all derivative instruments, NPNS, and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of March 31, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The amounts in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX, and Nodal commodity exchanges.

Rating as of March 31, 2021	Total Exposure Before Credit Collateral	Credit Collateral ^(a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10 % of Net Exposure
Investment grade	\$ 431	\$ 31	\$ 400	—	\$ —
Non-investment grade	43	4	39		
No external ratings					
Internally rated — investment grade	146	1	145		
Internally rated — non-investment grade	70	25	45		
Total	\$ 690	\$ 61	\$ 629	—	\$ —

Net Credit Exposure by Type of Counterparty	As of March 31, 2021
Investor-owned utilities, marketers, power producers	\$ 451
Energy cooperatives and municipalities	123
Other	55
Total	\$ 629

(a) As of March 31, 2021, credit collateral held from counterparties where Generation had credit exposure included \$32 million of cash and \$29 million of letters of credit. The credit collateral does not include non-liquid collateral.

Utility Registrants. 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. As of March 31, 2021, the Utility Registrants’ counterparty credit risk with suppliers was not material.

Credit-Risk-Related Contingent Features (All Registrants)

Generation. As part of the normal course of business, Generation routinely enters into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances, and other energy-related products. Certain of Generation’s derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation’s credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

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

Note 11 — Derivative Financial Instruments

The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Features	March 31, 2021	December 31, 2020
Gross fair value of derivative contracts containing this feature ^(a)	\$ (948)	\$ (834)
Offsetting fair value of in-the-money contracts under master netting arrangements ^(b)	518	537
Net fair value of derivative contracts containing this feature^(c)	\$ (430)	\$ (297)

- (a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk related contingent features ignoring the effects of master netting agreements.
- (b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which Generation could potentially be required to post collateral.
- (c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

As of March 31, 2021 and December 31, 2020, Exelon and Generation posted or held the following amounts of cash collateral and letters of credit on derivative contracts with external counterparties, after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

	March 31, 2021	December 31, 2020
Cash collateral posted	\$ 232	\$ 511
Letters of credit posted	242	226
Cash collateral held	101	110
Letters of credit held	41	40
Additional collateral required in the event of a credit downgrade below investment grade	1,379	1,432

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded.

Utility Registrants

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, 2021, 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, 2021, they could have been required to post incremental collateral to its counterparties of \$32 million, \$48 million and \$12 million, respectively.

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

Note 12 — Debt and Credit Agreements

12. 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. Generation and PECO meet 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 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 as of March 31, 2021 and December 31, 2020. PECO had no commercial paper borrowings as of both March 31, 2021 and December 31, 2020.

Commercial Paper Issuer	Outstanding Commercial Paper as of		Average Interest Rate on Commercial Paper Borrowings as of	
	March 31, 2021	December 31, 2020	March 31, 2021	December 31, 2020
Exelon ^{(a)(b)}	\$ 1,628	\$ 1,031	0.52 %	0.25 %
Generation ^(b)	1,337	340	0.60 %	0.27 %
ComEd	135	323	0.16 %	0.23 %
BGE	156	—	0.15 %	— %
PHI ^(c)	—	368	— %	0.24 %
Pepco	—	35	— %	0.22 %
DPL	—	146	— %	0.24 %
ACE	—	187	— %	0.25 %

(a) Exelon Corporate had no outstanding commercial paper borrowings as of both March 31, 2021 and December 31, 2020.

(b) Higher outstanding commercial paper primarily driven by increased liquidity needs from the February 2021 extreme cold weather event. See Note 3 – Regulatory Matters for additional information.

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

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for \$500 million. The loan agreement was renewed on March 17, 2021 and will expire on March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On March 24, 2021, Exelon Corporate entered into a 9-month term loan agreement for \$200 million. The loan agreement has an expiration of December 24, 2021. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On March 31, 2021, Exelon Corporate entered into a 9-month and 364-day term loan agreement for \$150 million each with variable interest rates of LIBOR plus 0.65% and expiration dates of December 31, 2021 and March 30, 2022, respectively. The loan agreements are reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On March 19, 2020, Generation entered into a term loan agreement for \$200 million. The loan agreement was renewed on March 17, 2021 and will expire on March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.875% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's and Generation's Consolidated Balance Sheets within Short-term borrowings.

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

Note 12 — Debt and Credit Agreements

On March 31, 2020, Generation entered into a term loan agreement for \$300 million. The loan agreement was renewed on March 30, 2021 and will expire on March 29, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.70% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's and Generation's Consolidated Balance Sheets within Short-term borrowings.

On January 25, 2021, ComEd entered into two 90-day term loan agreements for \$125 million each with variable interest rates of LIBOR plus 0.50% and LIBOR plus 0.75%, respectively. ComEd repaid the term loans on March 9, 2021.

Bilateral Credit Agreements

On January 11, 2013, Generation entered into a bilateral credit agreement for \$100 million. The agreement was renewed on March 1, 2021 with a maturity date of March 1, 2023.

On February 21, 2019, Generation entered into a bilateral credit agreement for \$100 million. The agreement was renewed on March 31, 2021 with a maturity date of March 31, 2022.

On January 5, 2016, Generation entered into a bilateral credit agreement for \$150 million. The agreement was renewed on April 2, 2021 with a maturity date of April 5, 2023.

Long-Term Debt

Issuance of Long-Term Debt

During the three months ended March 31, 2021, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Long-Term Software License Agreements	3.62 %	December 1, 2025	\$ 4	Procurement of software licenses.
Generation	Energy Efficiency Project Financing ^(a)	2.53 %	May 31, 2021	1	Funding to install energy conservation measures for the Fort AP Hill project.
ComEd	First Mortgage Bonds, Series 130	3.13 %	March 15, 2051	700	Repay a portion of outstanding commercial paper obligations and two outstanding term loans, and to fund other general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.05 %	March 15, 2051	375	Funding for general corporate purposes.
Pepco ^(b)	First Mortgage Bonds	2.32 %	March 30, 2031	150	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	3.24 %	March 30, 2051	125	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	2.30 %	March 15, 2031	350	Refinance existing indebtedness, repay outstanding commercial paper obligations, and for general corporate purposes.

(a) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

(b) On March 30, 2021, Pepco entered into a purchase agreement of First Mortgage Bonds of \$125 million at 3.29% due on September 28, 2051. The closing date of the issuance is expected to occur in September 2021.

Debt Covenants

As of March 31, 2021, 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 13 — Fair Value of Financial Assets and Liabilities

13. 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, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of March 31, 2021 and December 31, 2020. The Registrants have no financial liabilities classified as Level 1.

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

	March 31, 2021				December 31, 2020			
	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	\$ 38,529	\$ 39,255	\$ 3,115	\$ 42,370	\$ 36,912	\$ 40,688	\$ 3,064	\$ 43,752
Generation	6,060	5,497	1,158	6,655	6,087	5,648	1,208	6,856
ComEd	9,674	10,853	—	10,853	8,983	11,117	—	11,117
PECO	4,125	4,491	50	4,541	3,753	4,553	50	4,603
BGE	3,665	3,991	—	3,991	3,664	4,366	—	4,366
PHI	7,577	6,050	1,907	7,957	7,006	6,099	1,806	7,905
Pepco	3,317	3,112	823	3,935	3,165	3,336	748	4,084
DPL	1,802	1,386	524	1,910	1,677	1,484	455	1,939
ACE	1,718	1,302	560	1,862	1,413	1,018	602	1,620
Long-Term Debt to Financing Trusts^(a)								
Exelon	\$ 390	\$ —	\$ 465	\$ 465	\$ 390	\$ —	\$ 467	\$ 467
ComEd	205	—	243	243	205	—	246	246
PECO	184	—	222	222	184	—	221	221
SNF Obligation								
Exelon	\$ 1,208	\$ 979	\$ —	\$ 979	\$ 1,208	\$ 909	\$ —	\$ 909
Generation	1,208	979	—	979	1,208	909	—	909

(a) Includes unamortized debt issuance costs which are not fair valued.

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

Note 13 — 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, 2021 and December 31, 2020:

Exelon and Generation

As of March 31, 2021	Exelon					Generation				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents ^(a)	\$ 968	\$ —	\$ —	\$ —	\$ 968	\$ 125	\$ —	\$ —	\$ —	\$ 125
NDT fund investments										
Cash equivalents ^(b)	509	95	—	—	604	509	95	—	—	604
Equities	4,439	1,574	—	1,555	7,568	4,439	1,574	—	1,555	7,568
Fixed income										
Corporate debt ^(c)	—	1,023	283	—	1,306	—	1,023	283	—	1,306
U.S. Treasury and agencies	2,030	41	—	—	2,071	2,030	41	—	—	2,071
Foreign governments	—	51	—	—	51	—	51	—	—	51
State and municipal debt	—	40	—	—	40	—	40	—	—	40
Other	40	35	—	1,285	1,360	40	35	—	1,285	1,360
Fixed income subtotal	2,070	1,190	283	1,285	4,828	2,070	1,190	283	1,285	4,828
Private credit	—	—	196	617	813	—	—	196	617	813
Private equity	—	—	—	532	532	—	—	—	532	532
Real estate	—	—	—	686	686	—	—	—	686	686
NDT fund investments subtotal ^{(d)(e)}	7,018	2,859	479	4,675	15,031	7,018	2,859	479	4,675	15,031
Rabbi trust investments										
Cash equivalents	60	—	—	—	60	4	—	—	—	4
Mutual funds	95	—	—	—	95	31	—	—	—	31
Fixed income	—	10	—	—	10	—	—	—	—	—
Life insurance contracts	—	89	35	—	124	—	29	—	—	29
Rabbi trust investments subtotal	155	99	35	—	289	35	29	—	—	64
Investments in equities ^(f)	177	—	—	—	177	177	—	—	—	177
Commodity derivative assets										
Economic hedges	478	1,748	1,740	—	3,966	478	1,748	1,740	—	3,966
Proprietary trading	—	16	17	—	33	—	16	17	—	33
Effect of netting and allocation of collateral ^{(g)(h)}	(356)	(1,387)	(1,199)	—	(2,942)	(356)	(1,387)	(1,199)	—	(2,942)
Commodity derivative assets subtotal	122	377	558	—	1,057	122	377	558	—	1,057
DPP consideration	—	401	—	—	401	—	401	—	—	401

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

Note 13 — Fair Value of Financial Assets and Liabilities

As of March 31, 2021	Exelon					Generation				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Total assets	8,440	3,736	1,072	4,675	17,923	7,477	3,666	1,037	4,675	16,855
Liabilities										
Commodity derivative liabilities										
Economic hedges	(359)	(1,642)	(1,945)	—	(3,946)	(359)	(1,642)	(1,650)	—	(3,651)
Proprietary trading	—	(9)	(5)	—	(14)	—	(9)	(5)	—	(14)
Effect of netting and allocation of collateral ^{(9)(h)}	252	1,532	1,304	—	3,088	252	1,532	1,304	—	3,088
Commodity derivative liabilities subtotal	(107)	(119)	(646)	—	(872)	(107)	(119)	(351)	—	(577)
Deferred compensation obligation	—	(146)	—	—	(146)	—	(43)	—	—	(43)
Total liabilities	(107)	(265)	(646)	—	(1,018)	(107)	(162)	(351)	—	(620)
Total net assets	<u>\$ 8,333</u>	<u>\$ 3,471</u>	<u>\$ 426</u>	<u>\$ 4,675</u>	<u>\$ 16,905</u>	<u>\$ 7,370</u>	<u>\$ 3,504</u>	<u>\$ 686</u>	<u>\$ 4,675</u>	<u>\$ 16,235</u>

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

Note 13 — Fair Value of Financial Assets and Liabilities

As of December 31, 2020	Exelon					Generation				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents ^(a)	\$ 686	\$ —	\$ —	\$ —	\$ 686	\$ 124	\$ —	\$ —	\$ —	\$ 124
NDT fund investments										
Cash equivalents ^(b)	210	95	—	—	305	210	95	—	—	305
Equities	3,886	2,077	—	1,562	7,525	3,886	2,077	—	1,562	7,525
Fixed income										
Corporate debt ^(c)	—	1,485	285	—	1,770	—	1,485	285	—	1,770
U.S. Treasury and agencies	1,871	126	—	—	1,997	1,871	126	—	—	1,997
Foreign governments	—	56	—	—	56	—	56	—	—	56
State and municipal debt	—	101	—	—	101	—	101	—	—	101
Other	—	41	—	961	1,002	—	41	—	961	1,002
Fixed income subtotal	1,871	1,809	285	961	4,926	1,871	1,809	285	961	4,926
Private credit	—	—	212	629	841	—	—	212	629	841
Private equity	—	—	—	504	504	—	—	—	504	504
Real estate	—	—	—	679	679	—	—	—	679	679
NDT fund investments subtotal ^{(d)(e)}	5,967	3,981	497	4,335	14,780	5,967	3,981	497	4,335	14,780
Rabbi trust investments										
Cash equivalents	60	—	—	—	60	4	—	—	—	4
Mutual funds	91	—	—	—	91	29	—	—	—	29
Fixed income	—	11	—	—	11	—	—	—	—	—
Life insurance contracts	—	87	34	—	121	—	28	—	—	28
Rabbi trust investments subtotal	151	98	34	—	283	33	28	—	—	61
Investments in equities ^(f)	195	—	—	—	195	195	—	—	—	195
Commodity derivative assets										
Economic hedges	745	1,914	1,599	—	4,258	745	1,914	1,599	—	4,258
Proprietary trading	—	17	27	—	44	—	17	27	—	44
Effect of netting and allocation of collateral ^{(g)(h)}	(607)	(1,597)	(905)	—	(3,109)	(607)	(1,597)	(905)	—	(3,109)
Commodity derivative assets subtotal	138	334	721	—	1,193	138	334	721	—	1,193
DPP consideration	—	639	—	—	639	—	639	—	—	639
Total assets	7,137	5,052	1,252	4,335	17,776	6,457	4,982	1,218	4,335	16,992
Liabilities										
Commodity derivative liabilities										
Economic hedges	(682)	(1,928)	(1,655)	—	(4,265)	(682)	(1,928)	(1,354)	—	(3,964)
Proprietary trading	—	(21)	(4)	—	(25)	—	(21)	(4)	—	(25)
Effect of netting and allocation of collateral ^{(g)(h)}	540	1,918	1,067	—	3,525	540	1,918	1,067	—	3,525
Commodity derivative liabilities subtotal	(142)	(31)	(592)	—	(765)	(142)	(31)	(291)	—	(464)
Deferred compensation obligation	—	(145)	—	—	(145)	—	(42)	—	—	(42)
Total liabilities	(142)	(176)	(592)	—	(910)	(142)	(73)	(291)	—	(506)
Total net assets	\$ 6,995	\$ 4,876	\$ 660	\$ 4,335	\$ 16,866	\$ 6,315	\$ 4,909	\$ 927	\$ 4,335	\$ 16,486

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

Note 13 — Fair Value of Financial Assets and Liabilities

- (a) Exelon excludes cash of \$1,273 million and \$409 million at March 31, 2021 and December 31, 2020, respectively, and restricted cash of \$93 million and \$59 million at March 31, 2021 and December 31, 2020, respectively, and includes long-term restricted cash of \$52 million and \$53 million at March 31, 2021 and December 31, 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Generation excludes cash of \$608 million and \$171 million at March 31, 2021 and December 31, 2020, respectively, and restricted cash of \$29 million and \$20 million at March 31, 2021 and December 31, 2020, respectively.
- (b) Includes \$108 million and \$116 million of cash received from outstanding repurchase agreements at March 31, 2021 and December 31, 2020, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (e) below.
- (c) Includes investments in equities sold short of \$(58) million and \$(62) million as of March 31, 2021 and December 31, 2020, respectively, held in an investment vehicle primarily to hedge the equity option component of its convertible debt.
- (d) Includes derivative assets of less than \$1 million and \$2 million, which have total notional amounts of \$2,049 million and \$1,043 million at March 31, 2021 and December 31, 2020, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of Exelon and Generation's exposure to credit or market loss.
- (e) Excludes net liabilities of \$104 million and \$181 million at March 31, 2021 and December 31, 2020, respectively, which include certain derivative assets that have notional amounts of \$158 million and \$104 million at March 31, 2021 and December 31, 2020, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.
- (f) Includes equity investments held by Generation which were previously designated as equity investments without readily determinable fair value but are now publicly traded and therefore have readily determinable fair values. Generation recorded the fair value of these investments in Other current assets on Exelon's and Generation's Consolidated Balance Sheets based on the quoted market prices of the stocks at March 31, 2021 and December 31, 2020, which resulted in unrealized gains of \$95 million and \$186 million within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income for the three months ended March 31, 2021 and for the year ended December 31, 2020, respectively.
- (g) Collateral (received)/posted from counterparties, net of collateral paid to counterparties, totaled \$(104) million, \$145 million, and \$105 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of March 31, 2021. Collateral (received)/posted from counterparties, net of collateral paid to counterparties, totaled \$(67) million, \$321 million, and \$162 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2020.
- (h) Of the collateral (received)/posted, \$(148) million and \$209 million represents variation margin on the exchanges as of March 31, 2021 and December 31, 2020, respectively.

As of March 31, 2021, Exelon and Generation have outstanding commitments to invest in private credit, private equity, and real estate investments of approximately \$298 million, \$239 million, and \$344 million, respectively. These commitments will be funded by Generation's existing NDT funds.

Exelon and Generation hold investments without readily determinable fair values with carrying amounts of \$61 million and \$50 million as of March 31, 2021, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the three months ended March 31, 2021.

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

Note 13 — Fair Value of Financial Assets and Liabilities

ComEd, PECO, and BGE

As of March 31, 2021	ComEd				PECO				BGE			
	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)	\$ 300	\$ —	\$ —	\$ 300	\$ 7	\$ —	\$ —	\$ 7	\$ —	\$ —	\$ —	\$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	9	—	—	9	11	—	—	11
Life insurance contracts	—	—	—	—	—	13	—	13	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	9	13	—	22	11	—	—	11
Total assets	300	—	—	300	16	13	—	29	11	—	—	11
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(9)	—	(9)	—	(6)	—	(6)
Mark-to-market derivative liabilities ^(b)	—	—	(295)	(295)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(295)	(303)	—	(9)	—	(9)	—	(6)	—	(6)
Total net assets (liabilities)	\$ 300	\$ (8)	\$ (295)	\$ (3)	\$ 16	\$ 4	\$ —	\$ 20	\$ 11	\$ (6)	\$ —	\$ 5

As of December 31, 2020	ComEd				PECO				BGE			
	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)	\$ 285	\$ —	\$ —	\$ 285	\$ 8	\$ —	\$ —	\$ 8	\$ 120	\$ —	\$ —	\$ 120
Rabbi trust investments												
Mutual funds	—	—	—	—	9	—	—	9	10	—	—	10
Life insurance contracts	—	—	—	—	—	13	—	13	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	9	13	—	22	10	—	—	10
Total assets	285	—	—	285	17	13	—	30	130	—	—	130
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(9)	—	(9)	—	(5)	—	(5)
Mark-to-market derivative liabilities ^(b)	—	—	(301)	(301)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(301)	(309)	—	(9)	—	(9)	—	(5)	—	(5)
Total net assets (liabilities)	\$ 285	\$ (8)	\$ (301)	\$ (24)	\$ 17	\$ 4	\$ —	\$ 21	\$ 130	\$ (5)	\$ —	\$ 125

(a) ComEd excludes cash of \$59 million and \$83 million at March 31, 2021 and December 31, 2020, respectively, and restricted cash of \$40 million and \$37 million at March 31, 2021 and December 31, 2020, respectively, and includes long-term restricted cash of \$43 million at both March 31, 2021 and December 31, 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of \$48 million and \$18 million at March 31, 2021 and December 31, 2020, respectively. BGE excludes cash of \$21 million and \$24 million at March 31, 2021 and December 31, 2020, respectively, and restricted cash of \$1 million at both March 31, 2021 and December 31, 2020.

(b) The Level 3 balance consists of the current and noncurrent liability of \$31 million and \$264 million, respectively, at March 31, 2021 and \$33 million and \$268 million, respectively, at December 31, 2020 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 13 — Fair Value of Financial Assets and Liabilities

PHI, Pepco, DPL, and ACE

PHI	As of March 31, 2021				As of December 31, 2020			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents ^(a)	\$ 527	\$ —	\$ —	\$ 527	\$ 86	\$ —	\$ —	\$ 86
Rabbi trust investments								
Cash equivalents	53	—	—	53	55	—	—	55
Mutual funds	15	—	—	15	14	—	—	14
Fixed income	—	10	—	10	—	11	—	11
Life insurance contracts	—	26	35	61	—	26	34	60
Rabbi trust investments subtotal	68	36	35	139	69	37	34	140
Total assets	595	36	35	666	155	37	34	226
Liabilities								
Deferred compensation obligation	—	(16)	—	(16)	—	(17)	—	(17)
Total liabilities	—	(16)	—	(16)	—	(17)	—	(17)
Total net assets	\$ 595	\$ 20	\$ 35	\$ 650	\$ 155	\$ 20	\$ 34	\$ 209

As of March 31, 2021	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)	\$ 128	\$ —	\$ —	\$ 128	\$ 50	\$ —	\$ —	\$ 50	\$ 349	\$ —	\$ —	\$ 349
Rabbi trust investments												
Cash equivalents	53	—	—	53	—	—	—	—	—	—	—	—
Fixed income	—	2	—	2	—	—	—	—	—	—	—	—
Life insurance contracts	—	26	35	61	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	53	28	35	116	—	—	—	—	—	—	—	—
Total assets	181	28	35	244	50	—	—	50	349	—	—	349
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets	\$ 181	\$ 26	\$ 35	\$ 242	\$ 50	\$ —	\$ —	\$ 50	\$ 349	\$ —	\$ —	\$ 349

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

Note 13 — Fair Value of Financial Assets and Liabilities

As of December 31, 2020	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)	\$ 35	\$ —	\$ —	\$ 35	\$ —	\$ —	\$ —	\$ —	\$ 13	\$ —	\$ —	\$ 13
Rabbi trust investments												
Cash equivalents	53	—	—	53	—	—	—	—	—	—	—	—
Fixed income	—	2	—	2	—	—	—	—	—	—	—	—
Life insurance contracts	—	26	34	60	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	53	28	34	115	—	—	—	—	—	—	—	—
Total assets	88	28	34	150	—	—	—	—	13	—	—	13
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets	\$ 88	\$ 26	\$ 34	\$ 148	\$ —	\$ —	\$ —	\$ —	\$ 13	\$ —	\$ —	\$ 13

(a) PHI excludes cash of \$72 million and \$74 million at March 31, 2021 and December 31, 2020, respectively, and restricted cash of \$5 million and none at March 31, 2021 and December 31, 2020, respectively, and includes long-term restricted cash of \$9 million and \$10 million at March 31, 2021 and December 31, 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Pepco excludes cash of \$34 million and \$30 million at March 31, 2021 and December 31, 2020, respectively, and restricted cash of \$5 million and none at March 31, 2021 and December 31, 2020, respectively. DPL excludes cash of \$14 million and \$15 million at March 31, 2021 and December 31, 2020, respectively. ACE excludes cash of \$17 million at both March 31, 2021 and December 31, 2020, respectively, and includes long-term restricted cash of \$9 million and \$10 million at March 31, 2021 and December 31, 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets.

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, 2021 and 2020:

Three months ended March 31, 2021	Exelon	Generation		ComEd		PHI and Pepco	Eliminated in Consolidation
	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	
Balance as of December 31, 2020	\$ 660	\$ 497	\$ 430	\$ 927	\$ (301)	\$ 34	\$ —
Total realized / unrealized gains (losses)							
Included in net income	(276)	1	(278) ^(a)	(277)	—	1	—
Included in noncurrent payables to affiliates	—	1	—	1	—	—	(1)
Included in regulatory assets	7	—	—	—	6 ^(b)	—	1
Change in collateral	(57)	—	(57)	(57)	—	—	—
Purchases, sales, issuances and settlements							
Purchases	109	—	109	109	—	—	—
Sales	1	—	1	1	—	—	—
Settlements	(20)	(20)	—	(20)	—	—	—
Transfers out of Level 3	2	—	2 ^(c)	2	—	—	—
Balance as of March 31, 2021	<u>\$ 426</u>	<u>\$ 479</u>	<u>\$ 207</u>	<u>\$ 686</u>	<u>\$ (295)</u>	<u>\$ 35</u>	<u>\$ —</u>
The amount of total (losses) gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of March 31, 2021							
	\$ (147)	\$ 1	\$ (149)	\$ (148)	\$ —	\$ 1	\$ —

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

Note 13 — Fair Value of Financial Assets and Liabilities

Three Months Ended March 31, 2020	Exelon		Generation		ComEd	PHI and Pepco		Eliminated in Consolidation
	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts		
Balance as of December 31, 2019	\$ 1,068	\$ 511	\$ 817	\$ 1,328	\$ (301)	\$ 41	\$ —	
Total realized / unrealized gains (losses)								
Included in net income	10	(1)	10 ^(a)	9	—	1	—	
Included in noncurrent payables to affiliates	—	(1)	—	(1)	—	—	1	
Included in regulatory assets	(14)	—	—	—	(13) ^(b)	—	(1)	
Change in collateral	1	—	1	1	—	—	—	
Purchases, sales, issuances and settlements								
Purchases	42	3	39	42	—	—	—	
Sales	(22)	—	(22)	(22)	—	—	—	
Settlements	(14)	(14)	—	(14)	—	—	—	
Transfers into Level 3	2	—	2 ^(c)	2	—	—	—	
Transfers out of Level 3	15	—	15 ^(c)	15	—	—	—	
Balance as of March 31, 2020	\$ 1,088	\$ 498	\$ 862	\$ 1,360	\$ (314)	\$ 42	\$ —	
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of March 31, 2020	\$ 187	\$ (1)	\$ 187	\$ 186	\$ —	\$ 1	\$ —	

- (a) Includes a reduction for the reclassification of \$129 million and \$177 million of realized losses due to the settlement of derivative contracts for the three months ended March 31, 2021 and 2020 respectively.
- (b) Includes \$2 million of decreases in fair value and an increase for realized losses due to settlements of \$8 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2021. Includes \$23 million of decrease in fair value and an increase for realized losses due to settlements of \$10 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2020.
- (c) Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2021 and 2020:

	Exelon				Generation			PHI and Pepco
	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance
Total (losses) gains for the three months ended March 31, 2021	\$ (116)	\$ (162)	\$ 1	\$ 1	\$ (116)	\$ (162)	\$ 1	\$ 1
Total unrealized (losses) gains for the three months ended March 31, 2021	(65)	(84)	1	1	(65)	(84)	1	1

	Exelon				Generation			PHI and Pepco
	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance
Total gains (losses) for the three months ended March 31, 2020	\$ 72	\$ (62)	\$ 1	\$ (1)	\$ 72	\$ (62)	\$ (1)	\$ 1
Total unrealized gains (losses) gains for the three months ended March 31, 2020	205	(18)	1	(1)	205	(18)	(1)	1

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

Note 13 — Fair Value of Financial Assets and Liabilities

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 18 — Fair Value of Financial Assets and Liabilities of the Exelon 2020 Form 10-K.

Valuation Techniques Used to Determine Net asset Value (Exelon and Generation)

Certain NDT Fund Investments are not classified within the fair value hierarchy and are included under the heading "Not subject to leveling" in the table above. These investments are measured at fair value using NAV per share as a practical expedient and include commingled funds, mutual funds which are not publicly quoted, managed private credit funds, private equity and real estate funds.

For commingled funds and mutual funds, which are not publicly quoted, the fair value is primarily derived from the quoted prices in active markets on the underlying securities and can typically be redeemed monthly with 30 or less days of notice and without further restrictions. For managed private credit funds, the fair value is determined using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on Exelon's understanding of the investment funds. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

Mark-to-Market Derivatives (Exelon, Generation and ComEd)

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

Type of trade	Fair Value at March 31, 2021	Fair Value at December 31, 2020	Valuation Technique	Unobservable Input	2021 Range & Arithmetic Average			2020 Range & Arithmetic Average		
Mark-to-market derivatives — Economic Hedges (Exelon and Generation) ^{(a)(b)}	\$ 90	\$ 245	Discounted Cash Flow	Forward power price	\$1.35 - \$235	\$32	\$2.25 - \$163	\$30		
				Forward gas price	\$1.42 - \$8.18	\$2.59	\$1.57 - \$7.88	\$2.59		
				Option Model	Volatility percentage	11% - 116%	27%	11% - 237%	32%	
Mark-to-market derivatives — Proprietary trading (Exelon and Generation) ^{(a)(b)}	\$ 12	\$ 23	Discounted Cash Flow	Forward power price	\$9 - \$102	\$30	\$10 - \$106	\$27		
Mark-to-market derivatives (Exelon and ComEd)	\$ (295)	\$ (301)	Discounted Cash Flow	Forward heat rate ^(c)	8x - 9x	8.85x	8x - 9x	8.85x		
				Marketability reserve	3% - 8%	4.93%	3% - 8%	4.93%		
				Renewable factor	90% - 123%	99%	91% - 123%	99%		

- (a) The valuation techniques, unobservable inputs, ranges and arithmetic averages are the same for the asset and liability positions.
- (b) The fair values do not include cash collateral posted on level three positions of \$105 million and \$162 million as of March 31, 2021 and December 31, 2020, respectively.
- (c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

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

Note 13 — Fair Value of Financial Assets and Liabilities

The inputs listed above, which are as of the balance sheet date, would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

14. Commitments and Contingencies (All Registrants)

The following is an update to the current status of commitments and contingencies set forth in Note 19 of the Exelon 2020 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, 2021:

<u>Description</u>	<u>Exelon</u>	<u>PHI</u>	<u>Pepco</u>	<u>DPL</u>	<u>ACE</u>
Total commitments	\$ 513	\$ 320	\$ 120	\$ 89	\$ 111
Remaining commitments ^(a)	79	64	53	7	4

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

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new solar generation in Maryland, District of Columbia, and Delaware at an estimated cost of approximately \$135 million, which will generate future earnings at Exelon and Generation. Investment costs, which are expected to be primarily capital in nature, are recognized as incurred and recorded in Exelon's and Generation's financial statements. As of March 31, 2021, 27 MWs of new generation were developed and Exelon and Generation have incurred costs of \$121 million. Exelon has also committed to purchase 100 MWs of wind energy in PJM. DPL has committed to conducting three RFPs to procure up to a total of 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards. DPL has conducted two of the three 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 DPSC in 2019. The third and final 40 MW wind REC tranche will be conducted in 2022.

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

Note 14 — Commitments and Contingencies

Commercial Commitments (All Registrants). The Registrants' commercial commitments as of March 31, 2021, representing commitments potentially triggered by future events were as follows:

	Total	Expiration within					2026 and beyond
		2021	2022	2023	2024	2025	
Exelon							
Letters of credit	\$ 1,639	\$ 1,156	\$ 483	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	1,077	919	158	—	—	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values ^(b)	29	—	3	4	6	5	11
Total commercial commitments	<u>\$ 3,123</u>	<u>\$ 2,075</u>	<u>\$ 644</u>	<u>\$ 4</u>	<u>\$ 6</u>	<u>\$ 5</u>	<u>\$ 389</u>
Generation							
Letters of credit	\$ 1,623	\$ 1,141	\$ 482	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	932	794	138	—	—	—	—
Total commercial commitments	<u>\$ 2,555</u>	<u>\$ 1,935</u>	<u>\$ 620</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>
ComEd							
Letters of credit	\$ 7	\$ 7	\$ —	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	17	14	3	—	—	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	<u>\$ 224</u>	<u>\$ 21</u>	<u>\$ 3</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 200</u>
PECO							
Surety bonds ^(a)	\$ 2	\$ 2	\$ —	\$ —	\$ —	\$ —	\$ —
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	<u>\$ 180</u>	<u>\$ 2</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 178</u>
BGE							
Letters of credit	\$ 3	\$ 2	\$ 1	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	3	3	—	—	—	—	—
Total commercial commitments	<u>\$ 6</u>	<u>\$ 5</u>	<u>\$ 1</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>
PHI							
Surety bonds ^(a)	\$ 23	\$ 20	\$ 3	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	29	—	3	4	6	5	11
Total commercial commitments	<u>\$ 52</u>	<u>\$ 20</u>	<u>\$ 6</u>	<u>\$ 4</u>	<u>\$ 6</u>	<u>\$ 5</u>	<u>\$ 11</u>
Pepco							
Surety bonds ^(a)	\$ 14	\$ 14	\$ —	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	10	—	1	1	2	2	4
Total commercial commitments	<u>\$ 24</u>	<u>\$ 14</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 2</u>	<u>\$ 2</u>	<u>\$ 4</u>
DPL							
Surety bonds ^(a)	\$ 5	\$ 2	\$ 3	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	12	—	1	2	3	2	4
Total commercial commitments	<u>\$ 17</u>	<u>\$ 2</u>	<u>\$ 4</u>	<u>\$ 2</u>	<u>\$ 3</u>	<u>\$ 2</u>	<u>\$ 4</u>
ACE							
Surety bonds ^(a)	\$ 4	\$ 4	\$ —	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	7	—	1	1	1	1	3
Total commercial commitments	<u>\$ 11</u>	<u>\$ 4</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 3</u>

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

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

Note 14 — 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 8 years. The maximum potential obligation at the end of the minimum lease term would be \$73 million guaranteed by Exelon and PHI, of which \$25 million, \$30 million, and \$18 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 (Exelon and the Utility 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 almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has 21 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 2026.
- PECO has 8 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 2023.
- 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 2023.
- 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 settlements of natural gas distribution rate cases with the PAPUC, 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 14 — Commitments and Contingencies

As of March 31, 2021 and December 31, 2020, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

	March 31, 2021		December 31, 2020	
	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	\$ 473	\$ 306	\$ 483	\$ 314
Generation	119	—	121	—
ComEd	281	280	293	293
PECO	23	21	23	21
BGE	6	5	2	—
PHI	44	—	44	—
Pepco	42	—	42	—
DPL	1	—	1	—
ACE	1	—	1	—

Cotter Corporation (Exelon and Generation). The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. Including Cotter, there are three PRPs participating in the West Lake Landfill remediation proceeding. Investigation by Generation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing.

In September 2018, the EPA issued its Record of Decision Amendment (RODA) for the selection of a final remedy. The RODA modified the remedy previously selected by EPA in its 2008 Record of Decision (ROD). While the ROD required only that the radiological materials and other wastes at the site be capped, the 2018 RODA requires partial excavation of the radiological materials in addition to the previously selected capping remedy. The RODA also allows for variation in depths of excavation depending on radiological concentrations. The EPA and the PRPs have entered into a Consent Agreement to perform the Remedial Design, which is expected to be completed by early 2022. In March 2019 the PRPs received Special Notice Letters from the EPA to perform the Remedial Action work. On October 8, 2019, Cotter (Generation's indemnitee) provided a non-binding good faith offer to conduct, or finance, a portion of the remedy, subject to certain conditions. The total estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred collectively by the PRPs in fully executing the remedy, is approximately \$280 million, including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. Generation has determined that a loss associated with the EPA's partial excavation and enhanced landfill cover remedy is probable and has recorded a liability included in the table above, that reflects management's best estimate of Cotter's allocable share of the ultimate cost. Given the joint and several nature of this liability, the magnitude of Generation's ultimate liability will depend on the actual costs incurred to implement the required remedy as well as on the nature and terms of any cost-sharing arrangements with the final group of PRPs. Therefore, it is reasonably possible that the ultimate cost and Cotter's associated allocable share could differ significantly once these uncertainties are resolved, which could have a material impact on Exelon's and Generation's future financial statements.

One of the other PRPs has indicated it will be making a contribution claim against Cotter for costs that it has incurred to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Exelon and Generation do not possess sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's financial statements.

In January 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. In September 2018, the PRPs agreed to an Administrative Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater Remedial

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

Note 14 — Commitments and Contingencies

Investigation and Feasibility Study (RI/FS). The purpose of this RI/FS is to define the nature and extent of any groundwater contamination from the West Lake Landfill site and evaluate remedial alternatives. Generation estimates the undiscounted cost for the groundwater RI/FS to be approximately \$30 million. Generation determined a loss associated with the RI/FS is probable and has recorded a liability included in the table above that reflects management's best estimate of Cotter's allocable share of the cost among the PRPs. At this time Generation cannot predict the likelihood or the extent to which, if any, remediation activities may be required and therefore cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's future financial statements.

In August 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's (now Generation's) indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until August 31, 2021 so that settlement discussions can proceed. On August 3, 2020, the DOJ advised Cotter and the other PRPs that it is seeking approximately \$90 million from all the PRPs and has directed that the PRPs must submit a good faith joint proposed settlement offer. At this time, the DOJ has stayed their request for a good faith offer while the parties review cost documentation associated with the cost claim. Generation has determined that a loss associated with this matter is probable under its indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above.

Benning Road Site (Exelon, Generation, 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 was formerly the location of a Pepco Energy Services electric generating facility, which 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 with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River.

Since 2013, Pepco and Pepco Energy Services (now Generation, pursuant to Exelon's 2016 acquisition of PHI) have been performing RI work and have submitted multiple draft RI reports to the DOEE. In September 2019, Pepco and Generation issued a draft "final" RI report which DOEE approved on February 3, 2020. Pepco and Generation are developing a FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the FS, and approval by the DOEE, by March 16, 2022. After completion and approval of the FS, DOEE will prepare a Proposed Plan for public comment and then issue a ROD identifying any further response actions determined to be necessary. PHI, Pepco, and Generation 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 Pepco and Generation, DOEE and the National Park Service 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 Pepco and Pepco Energy Services 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. In April 2018, DOEE released a draft RI report for public review and comment. Pepco submitted written comments to the draft RI and participated in a public hearing.

Pepco has determined that it is probable that costs for remediation will be incurred and recorded a liability in the third quarter 2019 for management's best estimate of its share of those costs. On September 30, 2020, DOEE released its Interim ROD. The Interim ROD reflects an adaptive management approach which will require several

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

Note 14 — Commitments and Contingencies

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. 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 Natural Resources Damages (NRD) assessment, a process that often takes many years beyond the remedial decision to complete. Pepco has concluded that a loss associated with the eventual NRD assessment is reasonably possible. Due to the very early stage of the assessment process, Pepco cannot reasonably estimate the range of loss.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon and Generation). Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At March 31, 2021 and December 31, 2020, Exelon and Generation had recorded estimated liabilities of approximately \$88 million and \$89 million, respectively, in total for asbestos-related bodily injury claims. As of March 31, 2021, approximately \$24 million of this amount related to 243 open claims presented to Generation, while the remaining \$64 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2055, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether adjustments to the estimated liabilities are necessary.

It is reasonably possible that additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued could have a material, unfavorable impact on Exelon’s and Generation’s financial statements. However, management cannot reasonably estimate a range of loss beyond the amounts recorded.

Deferred Prosecution Agreement (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 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 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.

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

Note 14 — Commitments and Contingencies

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:

- 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 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. Defendants' responsive pleading is due June 9, 2021.
- 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. These three state cases were consolidated into a single action in October of 2020. In addition, on November 2, 2020, the Citizens Utility Board (CUB) filed a motion to intervene in the state 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, to jointly engage in mediation and have informed the court. The parties will report back to the court on the status of the mediation planning on April 29, 2021. A tentative date of June 1, 2021 has been set for oral argument on the pending motion to dismiss, but the parties have agreed to extend that date so long as a date to mediate has been selected by that time.
- Four putative class action lawsuits against ComEd and Exelon were filed in federal court in the third quarter of 2020 alleging, among other things, civil violations of federal racketeering laws. In addition, CUB filed a motion to intervene in these cases on October 22, 2020 which was granted on December 23, 2020. In addition, on December 2, 2020, the court appointed interim lead plaintiffs in the federal cases which consisted of counsel for three of the four federal cases. These plaintiffs filed a consolidated complaint on January 5, 2021. CUB also filed its own complaint against ComEd only on the same day. The remaining federal case, Potter, et al. v. Exelon et al, differed from the other lawsuits as it named additional individual defendants not named in the consolidated complaint. The Potter plaintiffs decided not to move forward with their separate lawsuit at this time and voluntarily dismissed their complaint without prejudice on April 5, 2021. ComEd and Exelon moved to dismiss the consolidated class action complaint and CUB's complaint on February 4, 2021. Briefing on that motion was completed on March 22, 2021. As noted above, on March 25, 2021, the parties agreed, along with the state court plaintiffs, to jointly engage in mediation. The parties have notified the court of their decision to mediate. Oral argument on the pending motion to dismiss and any discovery will be stayed pending mediation.
- Five shareholders sent letters to the Exelon Board of Directors between 2020 and 2021 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.

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.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages (Exelon and Generation). Beginning on February 15, 2021, Generation's Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. See Note 3 — Regulatory Matters for additional information.

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

Note 14 — Commitments and Contingencies

Various lawsuits have been filed against Generation during March and April of 2021 related to these events, including:

- On March 5, 2021, Generation, along with more than 160 power generators and transmission and distribution companies, was sued by approximately 160 individually named plaintiffs, purportedly on behalf of all Texans who allegedly suffered loss of life or sustained personal injury, property damage or other losses as a result of the weather events. The plaintiffs allege that the defendants failed to properly prepare for the cold weather and failed to properly conduct their operations, seeking compensatory as well as punitive damages. On April 26, 2021, another multi-plaintiff lawsuit was filed on behalf of approximately 90 plaintiffs against more than 300 defendants, including Generation, involving similar allegations of liability and claims of personal injury and property damage. During March and April of 2021, approximately 45 additional wrongful death lawsuits, naming multiple defendants including Generation, were filed by individual plaintiffs in different Texas counties, all arising out of the February weather events. Co-defendants in these lawsuits include ERCOT, transmission and distribution utilities and other generators. Generation disputes liability and denies that it is responsible for any of plaintiffs' alleged claims and is vigorously contesting them. No loss contingencies have been reflected in Exelon's and Generation's consolidated financial statements with respect to these matters, as such contingencies are neither probable nor reasonably estimable at this time.
- On March 22, 2021, a LDC filed a lawsuit in Missouri federal court against Generation for breach of contract and unjust enrichment, seeking damages of approximately \$40 million. The plaintiff claims that Generation failed to deliver gas to its customers in February of 2021, causing the plaintiff to incur damages by forcing it to purchase gas for Generation's customers and by Generation's refusal to pay the resulting penalties. On March 26, 2021, Generation filed a complaint with the MPSC against the LDC to void the OFO penalties, or alternatively to grant a waiver or variance from the tariff requirements, to prohibit the LDC from billing or otherwise attempting to collect from Generation or any Missouri customer any portion of the penalties claimed by the LDC until the resolution of the complaint, and to prohibit the LDC from taking any retaliatory measure, including termination of service. Generation has requested expedited treatment, but there is no timeline by which the MPSC must act. Based on the penalty provisions within the tariff that was in effect at the relevant time, Exelon and Generation recorded a liability of approximately \$40 million as of March 31, 2021.

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 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.

15. Changes in Accumulated Other Comprehensive Income (Exelon)

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

Three Months Ended March 31, 2021	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items ^(a)	Foreign Currency Items	Total
Beginning balance	\$ (5)	\$ (3,372)	\$ (23)	\$ (3,400)
OCI before reclassifications	—	(2)	1	(1)
Amounts reclassified from AOCI	—	55	—	55
Net current-period OCI	—	53	1	54
Ending balance	\$ (5)	\$ (3,319)	\$ (22)	\$ (3,346)

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

Note 15 — Changes in Accumulated Other Comprehensive Income

Three Months Ended March 31, 2020	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items ^(a)	Foreign Currency Items	Total
Beginning balance	\$ (2)	\$ (3,165)	\$ (27)	\$ (3,194)
OCI before reclassifications	(1)	(7)	(8)	(16)
Amounts reclassified from AOCI	—	37	—	37
Net current-period OCI	(1)	30	(8)	21
Ending balance	\$ (3)	\$ (3,135)	\$ (35)	\$ (3,173)

(a) AOCI amounts are included in the computation of net periodic pension and OPEB cost. See Note 10 — 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,	
	2021	2020
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	\$ 1	\$ 4
Actuarial loss reclassified to periodic benefit cost	(19)	(17)
Pension and non-pension postretirement benefit plans valuation adjustment	—	3

16. Variable Interest Entities (Exelon, Generation, PHI and ACE)

At March 31, 2021 and December 31, 2020, Exelon, Generation, PHI, and ACE collectively consolidated several VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (see *Consolidated VIEs* below) and had significant interests in several other VIEs for which the applicable Registrant does not have the power to direct the entities' activities and, accordingly, was not the primary beneficiary (see *Unconsolidated VIEs* below). Consolidated and unconsolidated VIEs are aggregated to the extent that the entities have similar risk profiles.

Consolidated VIEs

The table below shows the carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the consolidated financial statements of Exelon, Generation, PHI, and ACE as of March 31, 2021 and December 31, 2020. The assets, except as noted in the footnotes to the table below, can only be used to settle obligations of the VIEs. The liabilities, except as noted in the footnote to the table below, are such that creditors, or beneficiaries, do not have recourse to the general credit of Exelon, Generation, PHI, and ACE.

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

Note 16 — Variable Interest Entities

	March 31, 2021				December 31, 2020			
	Exelon	Generation	PHI ^(a)	ACE	Exelon	Generation	PHI ^(a)	ACE
Cash and cash equivalents	\$ 175	\$ 175	\$ —	\$ —	\$ 98	\$ 98	\$ —	\$ —
Restricted cash and cash equivalents	37	33	4	4	47	44	3	3
Accounts receivable								
Customer	145	145	—	—	148	148	—	—
Other	35	35	—	—	36	36	—	—
Unamortized energy contract assets	22	22	—	—	22	22	—	—
Inventories, net								
Materials and supplies	242	242	—	—	244	244	—	—
Assets held for sale ^(b)	—	—	—	—	101	101	—	—
Other current assets	448	443	5	—	674	669	5	—
Total current assets	<u>1,104</u>	<u>1,095</u>	<u>9</u>	<u>4</u>	<u>1,370</u>	<u>1,362</u>	<u>8</u>	<u>3</u>
Property, plant, and equipment, net	5,747	5,747	—	—	5,803	5,803	—	—
Nuclear decommissioning trust funds	3,089	3,089	—	—	3,007	3,007	—	—
Unamortized energy contract assets	243	243	—	—	249	249	—	—
Other noncurrent assets	47	38	9	9	52	42	10	10
Total noncurrent assets	<u>9,126</u>	<u>9,117</u>	<u>9</u>	<u>9</u>	<u>9,111</u>	<u>9,101</u>	<u>10</u>	<u>10</u>
Total assets^(c)	<u>\$ 10,230</u>	<u>\$ 10,212</u>	<u>\$ 18</u>	<u>\$ 13</u>	<u>\$ 10,481</u>	<u>\$ 10,463</u>	<u>\$ 18</u>	<u>\$ 13</u>
Long-term debt due within one year	\$ 90	\$ 69	\$ 21	\$ 16	\$ 94	\$ 68	\$ 26	\$ 21
Accounts payable	95	95	—	—	81	81	—	—
Accrued expenses	67	67	—	—	70	70	—	—
Unamortized energy contract liabilities	3	3	—	—	4	4	—	—
Liabilities held for sale ^(b)	—	—	—	—	16	16	—	—
Other current liabilities	1	1	—	—	5	5	—	—
Total current liabilities	<u>256</u>	<u>235</u>	<u>21</u>	<u>16</u>	<u>270</u>	<u>244</u>	<u>26</u>	<u>21</u>
Long-term debt	861	861	—	—	889	889	—	—
Asset retirement obligations	2,347	2,347	—	—	2,318	2,318	—	—
Other noncurrent liabilities	116	116	—	—	129	129	—	—
Total noncurrent liabilities	<u>3,324</u>	<u>3,324</u>	<u>—</u>	<u>—</u>	<u>3,336</u>	<u>3,336</u>	<u>—</u>	<u>—</u>
Total liabilities^(d)	<u>\$ 3,580</u>	<u>\$ 3,559</u>	<u>\$ 21</u>	<u>\$ 16</u>	<u>\$ 3,606</u>	<u>\$ 3,580</u>	<u>\$ 26</u>	<u>\$ 21</u>

(a) Includes certain purchase accounting adjustments from the PHI merger not pushed down to ACE.

(b) In the fourth quarter of 2020, Generation entered into an agreement for the sale of a significant portion of Generation's solar business, and as a result of this transaction, Exelon and Generation reclassified the consolidated VIEs' solar assets and liabilities as held for sale. Completion of the transaction occurred in the first quarter of 2021. Refer to Note 2 - Mergers, Acquisitions, and Dispositions for additional information on the solar business.

(c) Exelon's and Generation's balances include unrestricted assets for current unamortized energy contract assets of \$22 million and \$22 million, non-current unamortized energy contract assets of \$222 million and \$249 million, Assets held for sale of \$0 million and \$9 million, and other unrestricted assets of \$1 million and \$1 million as of March 31, 2021 and December 31, 2020, respectively.

(d) Exelon's and Generation's balances include liabilities with recourse of \$2 million and \$8 million as of March 31, 2021 and December 31, 2020, respectively.

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

Note 16 — Variable Interest Entities

As of March 31, 2021 and December 31, 2020, Exelon's and Generation's consolidated VIEs consist of:

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason Generation is primary beneficiary:
CENG - A joint venture between Generation and EDF. Generation has a 50.01% equity ownership in CENG. See additional discussion below.	Disproportionate relationship between equity interest and operational control as a result of the NOSA described further below.	Generation conducts the operational activities.
EGRP - A collection of wind and solar project entities. Generation has a 51% equity ownership in EGRP. See additional discussion below.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
Bluestem Wind Energy Holdings, LLC - A Tax Equity structure which is consolidated by EGRP. Generation has a noncontrolling interest.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
Antelope Valley - A solar generating facility, which is 100% owned by Generation. Antelope Valley sells all of its output to PG&E through a PPA.	The PPA contract absorbs variability through a performance guarantee.	Generation conducts all activities.
Equity investment in distributed energy company - Generation has a 31% equity ownership. This distributed energy company has an interest in an unconsolidated VIE. (See Unconsolidated VIEs disclosure below). Generation fully impaired this investment in 2019.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
NER - A bankruptcy remote, special purpose entity which is 100% owned by Generation, which purchases certain of Generation's customer accounts receivable arising from the sale of retail electricity. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. See Note 6 - Accounts Receivable for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	Generation conducts all activities.

CENG - On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the NOSA pursuant to which Generation conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF.

EDF has the option to sell its 49.99% equity interest in CENG to Generation. On November 20, 2019, Generation received notice of EDF's intention to exercise the put option to sell its interest in CENG to Generation and the put automatically exercised on January 19, 2020. Refer to Note 2 - Mergers, Acquisitions, and Dispositions for additional information.

Exelon and Generation, where indicated, provide the following support to CENG:

- Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. See Note 19 — Commitments and Contingencies of the Exelon 2020 Form 10-K for more details,
- Generation and EDF share in the \$688 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance, and
- Exelon has executed an agreement to provide up to \$245 million to support the operations of CENG as well as a \$165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

EGRP - EGRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by EGRP. Generation owns a number of limited liability companies that build, own, and operate solar and wind power facilities some of which are owned by EGRP. While Generation or EGRP owns 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that certain of the solar and

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

Note 16 — Variable Interest Entities

wind entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of these solar and wind entities that qualify as VIEs because Generation controls the design, construction, and operation of the facilities. There is limited recourse to Generation related to certain solar and wind entities.

In 2017, Generation's interests in EGRP were contributed to and are pledged for the ExGen Renewables IV non-recourse debt project financing structure. Refer to Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on ExGen Renewables IV.

As of March 31, 2021 and December 31, 2020, Exelon's, PHI's and ACE's consolidated VIE consists of:

Consolidated VIEs:	Reason entity is a VIE:	Reason ACE is the primary beneficiary:
ACE Funding - A special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of Transition Bonds. Proceeds from the sale of each series of Transition Bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees.	ACE's equity investment is a variable interest as, by design, it absorbs any initial variability of ATF. The bondholders also have a variable interest for the investment made to purchase the Transition Bonds.	ACE controls the servicing activities.

Unconsolidated VIEs

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected in Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements.

As of March 31, 2021 and December 31, 2020, Exelon and Generation had significant unconsolidated variable interests in several VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements.

The following table presents summary information about Exelon's and Generation's significant unconsolidated VIE entities:

	March 31, 2021			December 31, 2020		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets ^(a)	\$ 789	\$ 386	\$ 1,175	\$ 777	\$ 401	\$ 1,178
Total liabilities ^(a)	95	218	313	61	223	284
Exelon's ownership interest in VIE ^(a)	—	150	150	—	157	157
Other ownership interests in VIE ^(a)	694	18	712	716	21	737

(a) These items represent amounts on the unconsolidated VIE balance sheets, not in Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. Exelon and Generation do not have any exposure to loss as they do not have a carrying amount in the equity investment VIEs as of March 31, 2021 and December 31, 2020.

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

Note 16 — Variable Interest Entities

As of March 31, 2021 and December 31, 2020, Exelon's and Generation's unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason Generation is not the primary beneficiary:
Equity investments in distributed energy companies - 1) Generation has a 90% equity ownership in a distributed energy company. 2) Generation, via a consolidated VIE, has a 90% equity ownership in another distributed energy company (See Consolidated VIEs disclosure above). Generation fully impaired this investment in 2019.	Similar structures to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation does not conduct the operational activities.
Energy Purchase and Sale agreements - Generation has several energy purchase and sale agreements with generating facilities.	PPA contracts that absorb variability through fixed pricing.	Generation does not conduct the operational activities.

17. 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.

	Operating revenues								
	Exelon	Generation	PHI	DPL					
Three Months Ended March 31, 2021									
Operating lease income	\$ 4	\$ 3	\$ 1	\$ 1					
Variable lease income	64	64	—	—					
Three Months Ended March 31, 2020									
Operating lease income	\$ 5	\$ 3	\$ 1	\$ 1					
Variable lease income	69	69	—	—					
	Taxes other than income taxes								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2021									
Utility taxes ^(a)	\$ 217	\$ 24	\$ 59	\$ 35	\$ 25	\$ 74	\$ 67	\$ 6	\$ 1
Property	154	68	8	4	42	32	21	10	1
Payroll	61	28	7	4	5	7	2	1	—
Three Months Ended March 31, 2020									
Utility taxes ^(a)	\$ 218	\$ 26	\$ 60	\$ 31	\$ 26	\$ 75	\$ 69	\$ 6	\$ —
Property	150	69	7	4	39	31	21	9	1
Payroll	63	31	7	4	4	8	2	1	1

(a) Generation's utility tax represents gross receipts tax related to its retail operations, and the Utility Registrants' utility taxes represents 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 17 — Supplemental Financial Information

	Other, net								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2021									
Decommissioning-related activities:									
Net realized income on NDT funds ^(a)									
Regulatory Agreement Units	\$ 291	\$ 291	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Non-Regulatory Agreement Units	203	203	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory Agreement Units	(82)	(82)	—	—	—	—	—	—	—
Non-Regulatory Agreement Units	(66)	(66)	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities ^(b)	(167)	(167)	—	—	—	—	—	—	—
Decommissioning-related activities	179	179	—	—	—	—	—	—	—
AFUDC — Equity	28	—	4	6	7	11	9	1	1
Non-service net periodic benefit cost	20	—	—	—	—	—	—	—	—
Three Months Ended March 31, 2020									
Decommissioning-related activities:									
Net realized income on NDT funds ^(a)									
Regulatory Agreement Units	\$ 47	\$ 47	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Non-Regulatory Agreement Units	82	82	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory Agreement Units	(932)	(932)	—	—	—	—	—	—	—
Non-Regulatory Agreement Units	(706)	(706)	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities ^(b)	709	709	—	—	—	—	—	—	—
Decommissioning-related activities	(800)	(800)	—	—	—	—	—	—	—
AFUDC — Equity	23	—	6	3	5	9	6	1	2
Non-service net periodic benefit cost	10	—	—	—	—	—	—	—	—

- (a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.
(b) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of income taxes related to all NDT fund activity for those units. See Note 10 — Asset Retirement Obligations of the Exelon 2020 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

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

Note 17 — Supplemental Financial Information

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	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2021									
Property, plant, and equipment ^(a)	\$ 1,522	\$ 928	\$ 239	\$ 82	\$ 106	\$ 154	\$ 67	\$ 42	\$ 37
Amortization of regulatory assets ^(a)	160	—	53	4	46	56	35	11	10
Amortization of intangible assets, net ^(a)	15	12	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities ^(b)	4	3	—	—	—	—	—	—	—
Nuclear fuel ^(c)	276	276	—	—	—	—	—	—	—
ARO accretion ^(d)	127	127	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	\$ 2,104	\$ 1,346	\$ 292	\$ 86	\$ 152	\$ 210	\$ 102	\$ 53	\$ 47
Three Months Ended March 31, 2020									
Property, plant, and equipment ^(a)	\$ 856	\$ 290	\$ 228	\$ 79	\$ 97	\$ 144	\$ 64	\$ 38	\$ 34
Amortization of regulatory assets ^(a)	149	—	45	7	46	50	31	10	9
Amortization of intangible assets, net ^(a)	16	14	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities ^(b)	2	2	—	—	—	—	—	—	—
Nuclear fuel ^(c)	231	231	—	—	—	—	—	—	—
ARO accretion ^(d)	124	124	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	\$ 1,378	\$ 661	\$ 273	\$ 86	\$ 143	\$ 194	\$ 95	\$ 48	\$ 43

- (a) Included in Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income.
- (b) Included in Operating revenues or Purchased power and fuel expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.
- (c) Included in Purchased power and fuel expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.
- (d) Included in Operating and maintenance expense 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 17 — Supplemental Financial Information

	Other non-cash operating activities								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2021									
Pension and non-pension postretirement benefit costs	\$ 95	\$ 26	\$ 32	\$ 2	\$ 14	\$ 12	\$ 2	\$ 1	\$ 3
Allowance for credit losses	85	34	13	24	4	10	5	4	1
Other decommissioning-related activity ^(a)	(322)	(332)	—	—	—	—	—	—	—
Energy-related options ^(b)	17	17	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates ^(c)	(129)	—	(54)	(10)	(18)	(46)	(26)	(9)	(11)
Long-term incentive plan	32	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	37	21	—	—	7	7	1	3	1
AFUDC - Equity	(28)	—	(4)	(6)	(7)	(11)	(9)	(1)	(1)
Three Months Ended March 31, 2020									
Pension and non-pension postretirement benefit costs	\$ 98	\$ 27	\$ 28	\$ 1	\$ 15	\$ 17	\$ 3	\$ 1	\$ 3
Allowance for credit losses	45	4	7	17	7	10	4	3	3
Other decommissioning-related activity ^(a)	128	128	—	—	—	—	—	—	—
Energy-related options ^(b)	6	6	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates ^(d)	(71)	—	(17)	—	(35)	(19)	(15)	(4)	—
Long-term incentive plan	(7)	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	51	35	—	—	8	5	2	2	1
AFUDC - Equity	(23)	—	(6)	(3)	(5)	(9)	(6)	(1)	(2)

- (a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income, and income taxes related to all NDT fund activity for these units. See Note 10 — Asset Retirement Obligations of the Exelon 2020 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
- (b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
- (c) 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 BGE, Pepco, and DPL, reflects the change in regulatory assets and liabilities associated with their decoupling mechanisms and transmission formula rates. For PECO and ACE, reflects the change in regulatory assets and liabilities associated with their transmission formula rates. See Note 3 — Regulatory Matters for additional information.
- (d) For ComEd, reflects the true-up adjustments in regulatory assets and liabilities associated with its distribution and energy efficiency formula rates. For BGE, Pepco, and DPL, reflects the change in regulatory assets and liabilities associated with their decoupling mechanisms. See Note 3 — Regulatory Matters for additional information.

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

Note 17 — 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.

	<u>Exelon</u>	<u>Generation</u>	<u>ComEd</u>	<u>PECO</u>	<u>BGE</u>	<u>PHI</u>	<u>Pepco</u>	<u>DPL</u>	<u>ACE</u>
March 31, 2021									
Cash and cash equivalents	\$ 1,908	\$ 721	\$ 86	\$ 48	\$ 21	\$ 558	\$ 134	\$ 64	\$ 353
Restricted cash and cash equivalents	374	41	270	7	1	37	33	—	4
Restricted cash included in other long-term assets	52	—	43	—	—	9	—	—	9
Total cash, restricted cash, and cash equivalents	<u>\$ 2,334</u>	<u>\$ 762</u>	<u>\$ 399</u>	<u>\$ 55</u>	<u>\$ 22</u>	<u>\$ 604</u>	<u>\$ 167</u>	<u>\$ 64</u>	<u>\$ 366</u>
December 31, 2020									
Cash and cash equivalents	\$ 663	\$ 226	\$ 83	\$ 19	\$ 144	\$ 111	\$ 30	\$ 15	\$ 17
Restricted cash and cash equivalents	438	89	279	7	1	39	35	—	3
Restricted cash included in other long-term assets	53	—	43	—	—	10	—	—	10
Cash, restricted cash, and cash equivalents - Held for Sale	12	12	—	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	<u>\$ 1,166</u>	<u>\$ 327</u>	<u>\$ 405</u>	<u>\$ 26</u>	<u>\$ 145</u>	<u>\$ 160</u>	<u>\$ 65</u>	<u>\$ 15</u>	<u>\$ 30</u>
March 31, 2020									
Cash and cash equivalents	\$ 1,457	\$ 821	\$ 514	\$ 31	\$ 11	\$ 49	\$ 18	\$ 7	\$ 8
Restricted cash and cash equivalents	414	150	211	7	1	37	33	—	3
Restricted cash included in other long-term assets	121	—	108	—	—	12	—	—	12
Total cash, restricted cash, and cash equivalents	<u>\$ 1,992</u>	<u>\$ 971</u>	<u>\$ 833</u>	<u>\$ 38</u>	<u>\$ 12</u>	<u>\$ 98</u>	<u>\$ 51</u>	<u>\$ 7</u>	<u>\$ 23</u>
December 31, 2019									
Cash and cash equivalents	\$ 587	\$ 303	\$ 90	\$ 21	\$ 24	\$ 131	\$ 30	\$ 13	\$ 12
Restricted cash and cash equivalents	358	146	150	6	1	36	33	—	2
Restricted cash included in other long-term assets	177	—	163	—	—	14	—	—	14
Total cash, restricted cash, and cash equivalents	<u>\$ 1,122</u>	<u>\$ 449</u>	<u>\$ 403</u>	<u>\$ 27</u>	<u>\$ 25</u>	<u>\$ 181</u>	<u>\$ 63</u>	<u>\$ 13</u>	<u>\$ 28</u>

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the Exelon 2020 Form 10-K.

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

Note 17 — Supplemental Financial Information

Supplemental Balance Sheet Information

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

	Accrued expenses									
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE	
March 31, 2021										
Compensation-related accruals ^(a)	\$ 581	\$ 210	\$ 91	\$ 42	\$ 49	\$ 73	\$ 26	\$ 15	\$ 12	
Taxes accrued	540	279	70	18	50	108	92	10	12	
Interest accrued	424	76	65	36	41	79	37	20	20	
December 31, 2020										
Compensation-related accruals ^(a)	\$ 1,069	\$ 426	\$ 170	\$ 73	\$ 84	\$ 109	\$ 36	\$ 18	\$ 17	
Taxes accrued	527	229	94	16	73	117	90	18	12	
Interest accrued	331	44	109	37	46	51	26	7	12	

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

18. Related Party Transactions (All Registrants)

Operating revenues from affiliates

Generation

The following table presents Generation's Operating revenues from affiliates, which are primarily recorded as Purchased power from affiliates and an immaterial amount recorded as Operating and maintenance expense from affiliates at the Utility Registrants:

	Three Months Ended March 31,	
	2021	2020
Operating revenues from affiliates:		
ComEd ^{(a)(b)}	\$ 78	\$ 90
PECO ^(c)	42	37
BGE ^(d)	72	99
PHI	100	103
Pepco ^(e)	75	79
DPL ^(f)	21	22
ACE ^(g)	4	2
Other	3	1
Total operating revenues from affiliates (Generation)	<u>\$ 295</u>	<u>\$ 330</u>

(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs and ZECs to ComEd.

(b) For the three months ended March 31, 2021, ComEd's Purchased power from Generation of \$84 million is recorded as Operating revenues from ComEd of \$78 million and as Purchased power and fuel from ComEd of \$6 million at Generation. For the three months ended March 31, 2020, ComEd's Purchased power from Generation of \$97 million is recorded as Operating revenues from ComEd of \$90 million and as Purchased power and fuel from ComEd of \$7 million at Generation.

(c) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has a ten-year agreement with PECO to sell solar AECs.

(d) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs.

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

Note 18 — Related Party Transactions

- (e) Generation provides electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.
- (f) Generation provides a portion of DPL's energy requirements under its MDPSC and DPSC-approved market-based SOS commodity programs.
- (g) Generation provides electric supply to ACE under contracts executed through ACE's competitive procurement process.

PHI

PHI's Operating revenues from affiliates are primarily with BSC for services that PHISCO provides to BSC.

Operating and maintenance expense from affiliates

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,	
	2021	2020	2021	2020
Exelon				
BSC			\$ 124	\$ 113
PHISCO			17	14
Generation				
BSC	\$ 144	\$ 140	10	11
ComEd				
BSC	71	72	45	42
PECO				
BSC	39	37	17	16
BGE				
BSC	43	41	20	28
PHI				
BSC	39	37	32	16
PHISCO	—	—	17	14
Pepco				
BSC	22	21	13	6
PHISCO	30	30	7	6
DPL				
BSC	14	13	10	5
PHISCO	25	24	5	4
ACE				
BSC	12	11	8	4
PHISCO	22	22	5	4

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

Note 18 — Related Party Transactions

Current Receivables from/Payables to affiliates

The following tables present current receivables from affiliates and current payables to affiliates:

March 31, 2021

Payables to affiliates:	Receivables from affiliates:										
	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	BSC	PHISCO	Other	Total
Generation		\$ 17	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 84	\$ —	\$ 24	\$ 125
ComEd	\$ 50 ^(a)	—	—	—	—	—	—	49	—	5	104
PECO	15	—	—	—	—	—	—	24	—	7	46
BGE	11	1	—	—	—	—	—	30	—	1	43
PHI	—	1	—	—	—	—	—	7	—	10	18
Pepco	12	1	—	—	—	—	—	16	14	1	44
DPL	2	—	—	—	—	—	—	11	11	—	24
ACE	8	—	—	—	—	—	—	8	10	1	27
Other	8	1	—	—	—	—	1	—	—	—	10
Total	\$ 106	\$ 21	\$ —	\$ —	\$ —	\$ —	\$ 1	\$ 229	\$ 35	\$ 49	\$ 441

December 31, 2020

Payables to affiliates:	Receivables from affiliates:										
	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	BSC	PHISCO	Other	Total
Generation		\$ 13	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 72	\$ —	\$ 22	\$ 107
ComEd	\$ 78 ^(a)	—	—	—	—	—	—	59	—	9	146
PECO	17	1	—	—	—	—	—	28	—	4	50
BGE	11	—	—	—	—	—	—	47	—	3	61
PHI	—	—	—	—	—	—	—	4	—	11	15
Pepco	13	2	—	1	—	—	—	25	14	—	55
DPL	3	1	—	—	—	—	—	21	10	1	36
ACE	6	—	—	—	—	—	—	15	9	1	31
Other	25	5	2	2	2	1	6	—	—	—	43
Total	\$ 153	\$ 22	\$ 2	\$ 3	\$ 2	\$ 1	\$ 6	\$ 271	\$ 33	\$ 51	\$ 544

(a) As of March 31, 2021 and December 31, 2020, Generation had a contract liability with ComEd for \$24 million and \$50 million, respectively, that was included in Other current liabilities on Generation's Consolidated Balance Sheets. At March 31, 2021 and December 31, 2020, ComEd had a Current Payable to Generation of \$26 million and \$28 million, respectively, on its Consolidated Balance Sheets, which consisted of Generation's Current Receivable from ComEd, partially offset by Generation's contract liability with ComEd.

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. Generation, ComEd, PECO, and PHI Corporate participate in the Exelon money pool. Pepco, DPL, and ACE participate in the PHI intercompany money pool.

Noncurrent Receivables from/Payables to affiliates

Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 10 — Asset Retirement Obligations of the Exelon 2020 Form 10-K for additional information.

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

Note 18 — Related Party Transactions

The following table presents noncurrent receivables from affiliates at ComEd and PECO which are recorded as noncurrent payables to affiliates at Generation:

	March 31, 2021	December 31, 2020
ComEd	\$ 2,375	\$ 2,541
PECO	490	475

Long-term debt to financing trusts

The following table presents Long-term debt to financing trusts:

	March 31, 2021			December 31, 2020		
	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	<u>\$ 390</u>	<u>\$ 205</u>	<u>\$ 184</u>	<u>\$ 390</u>	<u>\$ 205</u>	<u>\$ 184</u>

Long-term debt to affiliates

In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term debt to affiliates in Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate.

19. Planned 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. Under the separation plan, Exelon shareholders will retain their current shares of Exelon stock and receive a pro-rata distribution of shares of the new company's stock in a transaction that is expected to be tax-free to Exelon and its shareholders for U.S. federal income tax purposes. The actual number of shares to be distributed to Exelon shareholders will be determined prior to closing.

Exelon is targeting to complete the separation in the first quarter of 2022, subject to final approval by Exelon's Board of Directors, a Form 10 registration statement being declared effective by the SEC, regulatory approvals, and satisfaction of other conditions. The transaction is subject to approval by the FERC, NRC, and NYPSC and receipt of a private letter ruling from the IRS and tax opinion from Exelon's tax advisors.

On February 25, 2021, Exelon and Generation filed applications with the FERC, NYPSC, and NRC seeking approvals for the separation of Generation. On March 25, 2021, Exelon filed a request for a private letter ruling with the IRS to confirm the tax-free treatment of the planned separation. Exelon and Generation expect a decision from the FERC and the IRS in the third quarter of 2021, the NRC in the fourth quarter of 2021, and have requested a decision from the NYPSC before the end of 2021 but cannot predict if the applications will be approved as filed.

There can be no assurance that any separation transaction will ultimately occur or, if one does occur, of its terms or timing.

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 generation, delivery, and marketing of energy through Generation and the energy distribution and transmission businesses through ComEd, PECO, BGE, Pepco, DPL, and ACE.

Exelon has eleven reportable segments consisting of Generation's five reportable segments (Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions), 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 eight separate operating subsidiary registrants, Generation, 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, Generation, 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 (Loss) attributable to common shareholders by Registrant for the three months ended March 31, 2021 compared to the same period in 2020. For additional information regarding the financial results for the three months ended March 31, 2021 and 2020 see the discussions of Results of Operations by Registrant.

	Three Months Ended March 31,		Favorable (unfavorable) variance
	2021	2020	
Exelon	\$ (289)	\$ 582	\$ (871)
Generation	(793)	45	(838)
ComEd	197	168	29
PECO	167	140	27
BGE	209	181	28
PHI	128	108	20
Pepco	59	52	7
DPL	56	45	11
ACE	14	13	1
Other ^(a)	(197)	(60)	(137)

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

Three Months Ended March 31, 2021 Compared to Three Months Ended March 31, 2020. Net income attributable to common shareholders decreased by \$871 million and diluted loss per average common share decreased to \$(0.30) in 2021 from \$0.60 in 2020 primarily due to:

- Impacts of the February 2021 extreme cold weather event;

- Accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024; and
- The absence of a prior year one-time tax settlement.

The decreases were partially offset by:

- Lower unrealized losses and higher realized gains on NDT funds;
- Higher electric distribution earnings from higher rate base and higher allowed ROE due to an increase in treasury rates at ComEd;
- The favorable impacts of the multi-year plan at BGE and regulatory rate increases at DPL; and
- Favorable weather conditions at PECO, DPL and ACE.

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 table provides a reconciliation between net income (loss) attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings (loss) for the three months ended March 31, 2021 compared to the same period in 2020.

	Three Months Ended March 31,			
	2021		2020	
(In millions, except per share data)	Earnings per Diluted Share		Earnings per Diluted Share	
Net Income (Loss) Attributable to Common Shareholders	\$ (289)	\$ (0.30)	\$ 582	\$ 0.60
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of \$46 and \$32, respectively)	(135)	(0.14)	(94)	(0.10)
Unrealized Losses Related to NDT Fund Investments (net of taxes of \$40 and \$405, respectively) ^(a)	43	0.04	485	0.50
Asset Impairments (net of taxes of \$1)	—	—	2	—
Plant Retirements and Divestitures (net of taxes of \$103 and \$4, respectively) ^(b)	310	0.32	13	0.01
Cost Management Program (net of taxes of \$0 and \$3, respectively) ^(c)	1	—	9	0.01
Change in Environmental Liabilities (net of taxes of \$1)	2	—	—	—
COVID-19 Direct Costs (net of taxes of \$4) ^(d)	10	0.01	—	—
Acquisition Related Costs (net of tax of \$2) ^(e)	6	0.01	—	—
ERP System Implementation Costs (net of taxes of \$1) ^(f)	5	0.01	—	—
Planned Separation Costs (net of taxes of \$2) ^(g)	7	0.01	—	—
Income Tax-Related Adjustments (entire amount represents tax expense)	(2)	—	(2)	—
Noncontrolling Interests (net of taxes of \$6 and \$30, respectively) ^(h)	(17)	(0.02)	(144)	(0.15)
Adjusted (non-GAAP) Operating Earnings (Loss)	\$ (60)	\$ (0.06)	\$ 851	\$ 0.87

Note:

Amounts may not sum due to rounding.

Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income (Loss) and Adjusted (non-GAAP) Operating Earnings (Loss) 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. For all items except the unrealized losses related to NDT fund investments, the marginal statutory income tax rates for 2021 and 2020 ranged from 25.0% to 29.0%. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized losses related to NDT fund investments were 48.0% and 45.5% for the three months ended March 31, 2021 and 2020, respectively.

- (a) Reflects the impact of net unrealized losses on Generation's NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.
- (b) In 2021, primarily reflects accelerated depreciation and amortization associated with Generation's decision in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024, partially offset by a gain on sale of Generation's solar business. In 2020, primarily reflects accelerated depreciation and amortization expenses associated with the early retirement of certain fossil sites.
- (c) Primarily represents reorganization costs related to cost management programs.
- (d) Represents direct costs related to COVID-19 consisting 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.
- (e) Reflects costs related to the acquisition of EDF's interest in CENG.
- (f) Reflects costs related to a multi-year Enterprise Resource Program (ERP) system implementation.
- (g) Represents costs related to the planned separation primarily comprised of third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the planned separation as well as employee-related severance costs.
- (h) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items, primarily related to unrealized gains and losses on NDT fund investments for CENG units.

Significant 2021 Transactions and Developments

Planned 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 with the resources necessary to best serve customers and sustain long-term investment and operating excellence. The separation gives each company the financial and strategic independence to focus on its specific customer needs, while executing its core business strategy.

On February 25, 2021, Exelon and Generation filed applications with the FERC, NYPSC, and NRC seeking approvals for the separation of Generation. On March 25, 2021, Exelon filed a request for a private letter ruling with the IRS to confirm the tax-free treatment of the planned separation. Exelon and Generation expect a decision from the FERC and the IRS in the third quarter of 2021, the NRC in the fourth quarter of 2021, and have requested a decision from the NYPSC before the end of 2021 but cannot predict if the applications will be approved as filed.

In connection with the planned separation, Exelon incurred transaction costs of approximately \$9 million on a pre-tax basis in the first quarter of 2021, which are excluded from Adjusted (non-GAAP) Operating Earnings. The transaction costs are primarily comprised of third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the planned separation as well as employee-related severance costs.

There can be no assurance that any separation transaction will ultimately occur or, if one does occur, of its terms or timing. See Note 19 — Planned Separation of the Combined Notes to Consolidated Financial Statements for additional information.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, Generation's Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions.

The estimated impact to Exelon's and Generation's Net income for the first quarter of 2021 arising from these market and weather conditions was a reduction of approximately \$880 million. The first quarter estimated impact includes certain charges associated with the natural gas business that may be reduced through waivers and/or recoveries from customers. Therefore, such charges are not included in the estimated full year earnings impact. Exelon and Generation estimate a reduction in Net income of approximately \$670 million to \$820 million for the full year 2021. The ultimate impact to Exelon's and Generation's consolidated financial statements may be affected by a number of factors, including final settlement data, the impacts of customer and counterparty credit losses, any state or federal solutions to address the financial challenges caused by the event, and related litigation and contract disputes. See Note 3 — Regulatory Matters and Note 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon expects to offset between \$410 million and \$490 million of this impact for the full year 2021 primarily at Generation through a combination of enhanced revenue opportunities, deferral of selected non-essential maintenance, and primarily one-time cost savings.

Agreement for the Sale of a Generation Biomass Facility (Exelon and Generation)

On April 28, 2021, Generation and ReGenerate entered into a purchase agreement, under which ReGenerate agreed to purchase Generation's interest in the Albany Green Energy biomass facility. Completion of the transaction is expected in the second half of 2021.

As a result, in the second quarter of 2021, Exelon and Generation will reclassify these assets and liabilities as held for sale and expect to record an impairment loss in a range of \$135 million to \$150 million on a pre-tax basis, which will be excluded from Exelon's and Generation's Adjusted (non-GAAP) Operating Earnings. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Utility Rates and Base Rate 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 2021. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these and other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Registrant/ Jurisdiction	Filing Date	Service	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois	April 16, 2020	Electric	\$ (11)	\$ (14)	8.38 %	December 9, 2020	January 1, 2021
BGE - Maryland	May 15, 2020 (amended September 11, 2020)	Electric	137	81	9.50 %	December 16, 2020	January 1, 2021
		Natural Gas	91	21	9.65 %		

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois	April 16, 2021	Electric	\$ 51	7.36 %	Fourth quarter of 2021
PECO - Pennsylvania	March 30, 2021	Electric	246	10.95 %	Fourth quarter of 2021
PECO - Pennsylvania	September 30, 2020	Natural Gas	69	10.95 %	Second quarter of 2021
Pepco - District of Columbia	May 30, 2019 (amended June 1, 2020)	Electric	136	9.7 %	Second quarter of 2021
Pepco - Maryland	October 26, 2020 (amended March 31, 2021)	Electric	104	10.2 %	Second quarter of 2021
DPL - Delaware	March 6, 2020 (amended February 2, 2021)	Electric	23	10.3 %	Third quarter of 2021
ACE - New Jersey	December 9, 2020 (amended February 26, 2021)	Electric	67	10.3 %	Fourth quarter of 2021

Transmission Formula Rates

The following total increases were included in ComEd's 2021 electric transmission formula rate update. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Registrant	Initial Revenue Requirement Increase	Annual Reconciliation Increase	Total Revenue Requirement Increase	Allowed Return on Rate Base	Allowed ROE
ComEd	\$ 33	\$ 12	\$ 45	8.20 %	11.50 %

Other Key Business Drivers and Management Strategies

The following discussion of other key business driver 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 and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Key Business Drivers and Management Strategies in the Registrants' combined 2020 Form 10-K and Note 14 — Commitments and Contingencies to the Consolidated Financial Statements in this report for additional information on various environmental matters.

Power Markets

Complaint at FERC Seeking to Alter Capacity Market Default Offer Caps

On February 21, 2019, PJM's Independent Market Monitor (IMM) filed a complaint alleging that the number of performance assessment intervals used to calculate the default offer cap for bids to supply capacity in PJM is too high, resulting in an overstated default offer cap that obviates the need for most sellers to seek unit-specific approval of their offers. The IMM claims that this allows for the exercise of market power. The IMM asks FERC to require PJM to reduce the number of performance assessment intervals used to calculate the opportunity costs of a capacity supplier assuming a capacity obligation. This would, in turn, lower the default offer cap and allow the IMM to review more offers on a unit-specific basis. Several consumer advocates filed a complaint seeking similar relief several months after the IMM's complaint. On March 18, 2021, FERC granted the complaints, finding the current estimate of performance assessment intervals to be excessive compared to the reasonably expected number of performance assessment intervals which results in an unjust and unreasonable default offer cap. FERC did not establish the number of performance assessment intervals that should be used to calculate the default offer cap and instead request briefs on the matter, including alternative approaches to mitigation in the capacity market. FERC clarified that the capacity auction for delivery year 2022/2023 (scheduled for May 2021) should go forward as scheduled under the current rules. It is too early to predict the final outcome of this proceeding or its potential financial impact, if any, on Exelon or Generation.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. As of March 31, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% for 2021. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk.

Generation procures natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Approximately 60% of Generation's uranium concentrate requirements from 2021 through 2025 are supplied by three suppliers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's consolidated financial statements.

See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements and ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Other Legislative and Regulatory Developments

FERC Supplemental Notice of Proposed Rulemaking

On April 15, 2021, the FERC issued a Supplemental Notice of Proposed Rulemaking (NOPR) proposing to modify the current regulation permitting a continuous 50-basis-point ROE incentive adder for a transmission utility that joins and remains a member of a RTO. Under the NOPR, the ROE incentive adder would only be available for a period of up to three years after a transmission utility newly joins a RTO and all existing ROE incentive adders would end for transmission utilities that have been members for three or more years. The Utility Registrants' existing transmission rates include the ROE incentive adder. Exelon plans to provide comments to FERC on this matter which are due by May 26, 2021. Exelon cannot predict the outcome, but a final rule as proposed could have an adverse impact to Exelon's and the Utility Registrants' financial statements. See Note 3 — Regulatory Matters of the 2020 Form 10-K for additional information regarding the Utility Registrants' transmission formula rates and regulatory proceedings at the FERC.

Employees

In April 2021, PECO ratified two CBAs with IBEW Local 614 which covers 1,140 operations employees and 185 customer service employees, respectively. Both CBAs expire in 2026.

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. At March 31, 2021, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2020. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in the Registrants' 2020 Form 10-K for further information.

Results of Operations by Registrant

Results of Operations — Generation

Generation's Results of Operations includes discussion of RNF, which is a financial measure not 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 CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on RNF. Generation believes that RNF is a useful measure because it provides information that can be used to evaluate its operational performance.

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2021	2020	
Operating revenues	\$ 5,559	\$ 4,733	\$ 826
Purchased power and fuel expense	4,610	2,704	(1,906)
Revenues net of purchased power and fuel expense	949	2,029	(1,080)
Other operating expenses			
Operating and maintenance	1,001	1,263	262
Depreciation and amortization	940	304	(636)
Taxes other than income taxes	121	129	8
Total other operating expenses	2,062	1,696	(366)
Gain on sales of assets and businesses	71	—	71
Operating (loss) income	(1,042)	333	(1,375)
Other income and (deductions)			
Interest expense, net	(72)	(109)	37
Other, net	167	(771)	938
Total other income and (deductions)	95	(880)	975
Loss before income taxes	(947)	(547)	(400)
Income taxes	(179)	(389)	(210)
Equity in losses of unconsolidated affiliates	(1)	(3)	2
Net loss	(769)	(161)	(608)
Net income (loss) attributable to noncontrolling interests	24	(206)	230
Net (loss) income attributable to membership interest	<u>\$ (793)</u>	<u>\$ 45</u>	<u>\$ (838)</u>

Three Months Ended March 31, 2021 Compared to Three Months Ended March 31, 2020. Net income attributable to membership interest decreased by \$838 million primarily due to:

- Impacts of the February 2021 extreme cold weather event;
- Accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024; and
- The absence of a prior year one-time tax settlement.

The decreases were partially offset by:

- Lower unrealized losses and higher realized gains on NDT funds.

Revenues Net of Purchased Power and Fuel Expense. The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Generation's five reportable segments are Mid-

Atlantic, Midwest, New York, ERCOT, and Other Power Regions. See Note 5 - Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on these reportable segments.

The following business activities are not allocated to a region and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to overall operating revenues or results of operations. Further, the following activities are not allocated to a region and are reported in Other: accelerated nuclear fuel amortization associated with nuclear decommissioning and other miscellaneous revenues.

Generation evaluates the operating performance of electric business activities using the measure of RNF. Operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.

For the three months ended March 31, 2021 compared to 2020, RNF by region were as follows. See Note 5 - Segment Information of the Combined Notes to the Consolidated Financial Statements for additional information on Purchase power and fuel expense for Generation's reportable segments.

	Three Months Ended March 31,		Variance	% Change
	2021	2020		
Mid-Atlantic ^(a)	\$ 567	\$ 567	\$ —	— %
Midwest ^(b)	702	727	(25)	(3.4)%
New York	242	193	49	25.4 %
ERCOT	(1,184)	80	(1,264)	(1,580.0)%
Other Power Regions	217	158	59	37.3 %
Total electric revenues net of purchased power and fuel expense	544	1,725	(1,181)	(68.5)%
Mark-to-market gains	175	131	44	33.6 %
Other	230	173	57	32.9 %
Total revenue net of purchased power and fuel expense	<u>\$ 949</u>	<u>\$ 2,029</u>	<u>\$(1,080)</u>	<u>(53.2)%</u>

(a) Includes results of transactions with PECO, BGE, Pepco, DPL, and ACE.

(b) Includes results of transactions with ComEd.

Generation's supply sources by region are summarized below:

Supply Source (GWs)	Three Months Ended March 31,		Variance	% Change
	2021	2020		
Nuclear Generation^(a)				
Mid-Atlantic	13,254	12,784	470	3.7 %
Midwest	23,155	23,598	(443)	(1.9)%
New York	7,057	6,173	884	14.3 %
Total Nuclear Generation	43,466	42,555	911	2.1 %
Fossil and Renewables				
Mid-Atlantic	662	853	(191)	(22.4)%
Midwest	323	388	(65)	(16.8)%
New York	1	1	—	— %
ERCOT	2,783	3,012	(229)	(7.6)%
Other Power Regions	2,964	3,508	(544)	(15.5)%
Total Fossil and Renewables	6,733	7,762	(1,029)	(13.3)%
Purchased Power				
Mid-Atlantic	4,483	5,943	(1,460)	(24.6)%
Midwest	179	288	(109)	(37.8)%
ERCOT	772	991	(219)	(22.1)%
Other Power Regions	12,834	12,167	667	5.5 %
Total Purchased Power	18,268	19,389	(1,121)	(5.8)%
Total Supply/Sales by Region				
Mid-Atlantic ^(b)	18,399	19,580	(1,181)	(6.0)%
Midwest ^(b)	23,657	24,274	(617)	(2.5)%
New York	7,058	6,174	884	14.3 %
ERCOT	3,555	4,003	(448)	(11.2)%
Other Power Regions	15,798	15,675	123	0.8 %
Total Supply/Sales by Region	68,467	69,706	(1,239)	(1.8)%

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).

(b) Includes affiliate sales to PECO, BGE, Pepco, DPL, and ACE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.

For the three months ended March 31, 2021 compared to 2020, changes in **RNF** by region were as follows:

	(Decrease)/ Increase	2021 vs. 2020 Description
Mid-Atlantic	\$ —	<ul style="list-style-type: none"> • increased capacity revenue, offset by • decreased load served
Midwest	(25)	<ul style="list-style-type: none"> • decreased load served • decreased total ISO sales due to decreased generation
New York	49	<ul style="list-style-type: none"> • decreased nuclear outage days • increased ZEC revenues due to decreased nuclear outage days
ERCOT	(1,264)	<ul style="list-style-type: none"> • higher energy procurement costs due to the February 2021 extreme cold weather event, as well as the impact of ERCOT market participant defaults
Other Power Regions	59	<ul style="list-style-type: none"> • increase in newly contracted load • higher portfolio optimization • higher realized energy prices, partially offset by • decreased capacity revenue
Mark-to-market ^(a)	44	<ul style="list-style-type: none"> • gains on economic hedging activities of \$131 million in 2020 compared to gains of \$175 million in 2021
Other	57	<ul style="list-style-type: none"> • higher natural gas portfolio optimization partially offset by penalties associated with operational flow orders and curtailments as a result of the February 2021 extreme cold weather event, partially offset by • increase in accelerated nuclear fuel amortization associated with announced early plant retirements • decreased revenue related to the energy efficiency business
Total	<u>\$ (1,080)</u>	

(a) See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on mark-to-market gains.

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for the Generation-operated plants, which reflects ownership percentage of stations operated by Exelon, excluding Salem, which is operated by PSEG. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under

GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended March 31,	
	2021	2020
Nuclear fleet capacity factor	95.3 %	93.9 %
Refueling outage days	84	94
Non-refueling outage days	3	11

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

	Three Months Ended March 31, 2021	
	Increase (Decrease)	
Credit loss expense	\$	47
Labor, other benefits, contracting, and materials ^(a)		(27)
Nuclear refueling outage costs, including the co-owned Salem plants		(51)
Plant retirements and divestitures		(221)
Other		(10)
Total decrease	\$	(262)

(a) Primarily reflects decreased contracting costs.

Depreciation and amortization expense for the three months ended March 31, 2021 compared to the same period in 2020 increased primarily due to the accelerated depreciation and amortization associated with Generation's decision to early retire the Byron and Dresden nuclear facilities.

Gain on sales of assets and businesses for the three months ended March 31, 2021 compared to the same period in 2020 increased primarily due to a gain on sale of Generation's solar business.

Interest Expense for the three months ended March 31, 2021 compared to the same period in 2020 decreased primarily due to decreases in interest rates.

Other, net for the three months ended March 31, 2021 compared to the same period in 2020 increased due to activity described in the table below:

	Three Months Ended March 31,	
	2021	2020
Net unrealized losses on NDT funds ^(a)	\$ (66)	\$ (706)
Net realized gains on sale of NDT funds ^(a)	185	55
Interest and dividend income on NDT funds ^(a)	18	27
Contractual elimination of income tax expense ^(b)	42	(176)
Net unrealized losses from equity investments ^(c)	(23)	—
Other	11	29
Total other, net	\$ 167	\$ (771)

(a) Unrealized losses, realized gains, and interest and dividend income on the NDT funds are associated with the Non-Regulatory Agreement Units.

(b) Contractual elimination of income tax expense is associated with the income taxes on the NDT funds of the Regulatory Agreement units.

(c) Net unrealized losses on equity investments that became publicly traded entities in the fourth quarter of 2020 and the first quarter of 2021.

Effective income tax rates were 18.9% and 71.1% for the three months ended March 31, 2021 and 2020, respectively. See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information

Net income attributable to noncontrolling interests for the three months ended March 31, 2021 compared to the same period in 2020 increased primarily due to higher net gains on NDT fund investments for CENG.

Results of Operations — ComEd

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2021	2020	
Operating revenues	\$ 1,535	\$ 1,439	\$ 96
Operating expenses			
Purchased power expense	527	486	(41)
Operating and maintenance	316	317	1
Depreciation and amortization	292	273	(19)
Taxes other than income taxes	75	75	—
Total operating expenses	1,210	1,151	(59)
Operating income	325	288	37
Other income and (deductions)			
Interest expense, net	(96)	(94)	(2)
Other, net	7	10	(3)
Total other income and (deductions)	(89)	(84)	(5)
Income before income taxes	236	204	32
Income taxes	39	36	(3)
Net income	<u>\$ 197</u>	<u>\$ 168</u>	<u>\$ 29</u>

Three Months Ended March 31, 2021 Compared to Three Months Ended March 31, 2020. Net income increased \$29 million as compared to the same period in 2020, primarily due to increased electric distribution formula rate earnings (reflecting the impacts of higher rate base and higher allowed electric distribution ROE due to an increase in treasury rates).

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

	Three Months Ended March 31, 2021
	Increase
Distribution	\$ 21
Transmission	2
Energy efficiency	12
Other	12
	47
Regulatory required programs	49
Total increase	<u>\$ 96</u>

Revenue Decoupling. The demand for electricity is affected by weather conditions and customer usage. Operating revenues are not impacted by abnormal weather, usage per customer or number of customers as a result of the revenue decoupling mechanisms as allowed by 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, 2021 as compared to the same period in 2020, due to the impact of higher rate base and higher allowed ROE due to an increase in treasury rates.

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 during the three months ended March 31, 2021 as compared to the same period in 2020, primarily due to increased regulatory asset amortization, which is fully recoverable.

Other Revenue primarily includes assistance provided to other utilities through mutual assistance programs. The increase in Other revenue for the three months ended March 31, 2021 as compared to the same period in 2020, 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, and costs related to electricity, ZEC and REC procurement. 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 acts as the billing agent 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, 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 ComEd's revenue disaggregation.

The increase of \$41 million for the three months ended March 31, 2021 compared to the same period in 2020, respectively, in **Purchased power 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, 2021
	(Decrease) Increase
Storm-related costs	\$ (9)
Labor, other benefits, contracting and materials	8
Pension and non-pension postretirement benefits expense	1
Other	(6)
	(6)
Regulatory required programs ^(a)	5
Total decrease	\$ (1)

(a) 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, 2021	
	Increase	
Depreciation and amortization ^(a)	\$	11
Regulatory asset amortization ^(b)		8
Total increase	\$	19

(a) Reflects ongoing capital expenditures.

(b) Includes amortization of ComEd's energy efficiency formula rate regulatory asset and amortization related to the August 2020 storm regulatory asset.

Effective income tax rates were 16.5% and 17.6% for the three months ended March 31, 2021 and 2020, respectively. See Note 9 — 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
	2021	2020	
Operating revenues	\$ 889	\$ 813	\$ 76
Operating expenses			
Purchased power and fuel expense	316	283	(33)
Operating and maintenance	234	217	(17)
Depreciation and amortization	86	86	—
Taxes other than income taxes	43	39	(4)
Total operating expenses	679	625	(54)
Operating income	210	188	22
Other income and (deductions)			
Interest expense, net	(38)	(36)	(2)
Other, net	5	3	2
Total other income and (deductions)	(33)	(33)	—
Income before income taxes	177	155	22
Income taxes	10	15	5
Net income	\$ 167	\$ 140	\$ 27

Three Months Ended March 31, 2021 Compared to Three Months Ended March 31, 2020. Net income increased by \$27 million primarily due to favorable weather conditions and volume.

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

	Three Months Ended March 31, 2021		
	Increase (Decrease)		
	Electric	Gas	Total
Weather	\$ 21	\$ 16	\$ 37
Volume	12	2	14
Pricing	(6)	(1)	(7)
Transmission	1	—	1
Other	(2)	—	(2)
	26	17	43
Regulatory required programs	31	2	33
Total increase	\$ 57	\$ 19	\$ 76

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, 2021 compared to the same period in 2020, Operating revenues related to weather increased by the impact of favorable 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, 2021 compared to the same period in 2020 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
	2021	2020	Normal	From 2020	2021 vs. Normal
Three Months Ended March 31,					
Heating Degree-Days	2,302	1,989	2,418	15.7 %	(4.8)%
Cooling Degree-Days	5	—	1	n/a	400.0 %

Volume. Electric volume, exclusive of the effects of weather, for the three months ended March 31, 2021, compared to the same period in 2020, increased on a net basis due to an increase in usage for residential customers further increased by customer growth. Natural gas volume for the three months ended March 31, compared to the same period in 2020, remained relatively consistent.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,			Weather - Normal % Change ^(b)
	2021	2020	% Change	
Residential	3,767	3,254	15.8 %	6.2 %
Small commercial & industrial	1,881	1,905	(1.3)%	(5.1)%
Large commercial & industrial	3,272	3,421	(4.4)%	(5.0)%
Public authorities & electric railroads	149	151	(1.3)%	(1.4)%
Total electric retail deliveries ^(a)	9,069	8,731	3.9 %	(0.6)%

Number of Electric Customers	As of March 31,	
	2021	2020
Residential	1,512,255	1,499,019
Small commercial & industrial	154,637	154,056
Large commercial & industrial	3,109	3,093
Public authorities & electric railroads	10,237	10,096
Total	1,680,238	1,666,264

(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,			Weather - Normal % Change ^(b)
	2021	2020	% Change	
Residential	20,674	17,282	19.6 %	2.8 %
Small commercial & industrial	10,170	8,809	15.5 %	(0.2)%
Large commercial & industrial	7	9	(22.2)%	(0.6)%
Transportation	7,650	7,135	7.2 %	0.4 %
Total natural gas retail deliveries ^(a)	38,501	33,235	15.8 %	1.5 %

Number of Natural Gas Customers	As of March 31,	
	2021	2020
Residential	493,857	489,063
Small commercial & industrial	44,604	44,509
Large commercial & industrial	5	5
Transportation	685	727
Total	539,151	534,304

(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, 2021 compared to the same period in 2020 decreased primarily due to lower overall effective electric rates due to increased usage across all major customer classes.

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.

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 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 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.

Other revenue primarily includes revenue related to late payment charges. Other revenues for the three months ended March 31, 2021 compared to the same period in 2020, decreased as PECO ceased new late fees for all customers and restored service to customers upon request who were disconnected in the last twelve months beginning March of 2020.

See Note 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The increase of \$33 million for the three months ended March 31, 2021 compared to the same period in 2020, 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, 2021
	Increase (Decrease)
Labor, other benefits, contracting and materials	10
Credit loss expense	7
Storm-related costs	6
BSC costs	3
Regulatory Required Programs	(2)
Other	(7)
Total increase	\$ 17

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

	Three Months Ended March 31, 2021
	Increase (Decrease)
Depreciation and amortization ^(a)	\$ 3
Regulatory asset amortization	(3)
Total increase	\$ —

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Interest expense, net increased \$2 million for the three months ended March 31, 2021 compared to the same period in 2020, respectively, primarily due to the issuance of debt in June 2020 and March 2021.

Effective income tax rates were 5.6% and 9.7% for the three months ended March 31, 2021 and 2020, respectively. See Note 9 — 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
	2021	2020	
Operating revenues	\$ 974	\$ 937	\$ 37
Operating expenses			
Purchased power and fuel expense	331	288	(43)
Operating and maintenance	197	188	(9)
Depreciation and amortization	152	143	(9)
Taxes other than income taxes	72	69	(3)
Total operating expenses	752	688	(64)
Operating income	222	249	(27)
Other income and (deductions)			
Interest expense, net	(34)	(32)	(2)
Other, net	8	5	3
Total other income and (deductions)	(26)	(27)	1
Income before income taxes	196	222	(26)
Income taxes	(13)	41	54
Net income	\$ 209	\$ 181	\$ 28

Three Months Ended March 31, 2021 Compared to Three Months Ended March 31, 2020. Net income increased by \$28 million primarily due to favorable impacts of the multi-year plan. 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 plan.

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

	Three Months Ended March 31, 2021		
	(Decrease) Increase		
	Electric	Gas	Total
Distribution	\$ —	\$ (1)	\$ (1)
Transmission	3	—	3
Other	(7)	(1)	(8)
	(4)	(2)	(6)
Regulatory required programs	24	19	43
Total increase	\$ 20	\$ 17	\$ 37

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 bill stabilization adjustment (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.

	As of March 31,	
	2021	2020
Number of Electric Customers		
Residential	1,192,470	1,181,329
Small commercial & industrial	114,819	114,697
Large commercial & industrial	12,505	12,376
Public authorities & electric railroads	266	265
Total	1,320,060	1,308,667

Number of Natural Gas Customers	As of March 31,	
	2021	2020
Residential	648,824	641,608
Small commercial & industrial	38,318	38,381
Large commercial & industrial	6,120	6,078
Total	693,262	686,067

Distribution Revenue remained relatively consistent for the three months ended March 31, 2021, compared to the same period in 2020.

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.

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 \$43 million for the three months ended March 31, 2021 compared to the same period in 2020, 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, 2021
	Increase (Decrease)
Storm-related costs	\$ 6
BSC costs	2
Credit loss expense	(2)
Other	3
Total increase	\$ 9

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

	Three Months Ended March 31, 2021
	Increase
Depreciation and amortization ^(a)	\$ 9
Total increase	\$ 9

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Effective income tax rates were (6.6)% and 18.5% for the three months ended March 31, 2021 and 2020, respectively. The change is primarily due to the multi-year plan which resulted in the acceleration of certain income tax benefits. 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 plan and Note 9 — 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, 2021 compared to the same period in 2020. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	Three Months Ended March 31,		Favorable Variance
	2021	2020	
PHI	\$ 128	\$ 108	\$ 20
Pepco	59	52	7
DPL	56	45	11
ACE	14	13	1
Other ^(a)	(1)	(2)	1

(a) Primarily includes eliminating and consolidating adjustments, PHI's corporate operations, shared service entities, and other financing and investing activities.

Three Months Ended March 31, 2021 Compared to Three Months Ended March 31, 2020. Net Income increased by \$20 million primarily due to favorable weather conditions in DPL's Delaware and ACE's service territories and higher electric distribution rates at DPL.

Results of Operations — Pepco

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2021	2020	
Operating revenues	\$ 553	\$ 544	\$ 9
Operating expenses			
Purchased power expense	166	164	(2)
Operating and maintenance	108	111	3
Depreciation and amortization	102	95	(7)
Taxes other than income taxes	90	92	2
Total operating expenses	466	462	(4)
Operating income	87	82	5
Other income and (deductions)			
Interest expense, net	(34)	(34)	—
Other, net	12	9	3
Total other income and (deductions)	(22)	(25)	3
Income before income taxes	65	57	8
Income taxes	6	5	(1)
Net income	\$ 59	\$ 52	\$ 7

Three Months Ended March 31, 2021 Compared to Three Months Ended March 31, 2020. Net income remained relatively consistent.

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

	Three Months Ended March 31, 2021
	Increase (Decrease)
Distribution	\$ 3
Transmission	(3)
Other	4
	4
Regulatory required programs	5
Total increase	\$ 9

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 bill stabilization adjustment (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,	
	2021	2020
Residential	835,415	820,283
Small commercial & industrial	53,738	54,304
Large commercial & industrial	22,492	22,248
Public authorities & electric railroads	174	169
Total	911,819	897,004

Distribution Revenue increased for the three months ended March 31, 2021 compared to the same period in 2020, due to customer growth.

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.

Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DC PLUG, and SOS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, as Pepco remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, Pepco acts as the billing agent and therefore 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 \$2 million for the three months ended March 31, 2021 compared to the same period in 2020, 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, 2021
	(Decrease) Increase
Labor, other benefits, contracting and materials	\$ (6)
Pension and non-pension postretirement benefits expense	(1)
BSC and PHISCO costs	1
Credit loss expense	2
Other	1
Total decrease	<u>\$ (3)</u>

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

	Three Months Ended March 31, 2021
	Increase (Decrease)
Depreciation and amortization ^(a)	\$ 4
Regulatory asset amortization	(1)
Regulatory required programs	4
Total increase	<u>\$ 7</u>

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Effective income tax rates were 9.2% and 8.8% for the three months ended March 31, 2021 and 2020, respectively. See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

Results of Operations — DPL

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2021	2020	
Operating revenues	\$ 382	\$ 350	\$ 32
Operating expenses			
Purchased power and fuel expense	156	141	(15)
Operating and maintenance	83	79	(4)
Depreciation and amortization	53	48	(5)
Taxes other than income taxes	17	16	(1)
Total operating expenses	309	284	(25)
Operating income	73	66	7
Other income and (deductions)			
Interest expense, net	(15)	(16)	1
Other, net	3	2	1
Total other income and (deductions)	(12)	(14)	2
Income before income taxes	61	52	9
Income taxes	5	7	2
Net income	\$ 56	\$ 45	\$ 11

Three Months Ended March 31, 2021 Compared to Three Months Ended March 31, 2020. Net income increased by \$11 million primarily due to favorable weather conditions in DPL's Delaware electric and natural gas service territories and higher electric distribution rates.

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

	Three Months Ended March 31, 2021		
	Increase (Decrease)		
	Electric	Gas	Total
Weather	\$ 4	\$ 5	\$ 9
Volume	—	1	1
Distribution	5	—	5
Other	1	(1)	—
	10	5	15
Regulatory required programs	15	2	17
Total increase	\$ 25	\$ 7	\$ 32

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 bill stabilization adjustment (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, 2021 compared to the same period in 2020, Operating revenues related to weather increased due to the impact of favorable weather conditions in DPL's 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 DPL's Delaware electric service territory and a 30-year period in DPL's Delaware natural gas service territory. The changes in heating and cooling degree days in DPL's Delaware service territory for the three months ended March 31, 2021 compared to same period in 2020 and normal weather consisted of the following:

Delaware Electric Service Territory Three Months Ended March 31,	2021	2020	Normal	% Change	
				2021 vs. 2020	2021 vs. Normal
Heating Degree-Days	2,358	2,003	2,493	17.7 %	(5.4)%
Cooling Degree-Days	3	—	—	n/a	n/a

Delaware Natural Gas Service Territory Three Months Ended March 31,	2021	2020	Normal	% Change	
				2021 vs. 2020	2021 vs. Normal
Heating Degree-Days	2,358	2,003	2,497	17.7 %	(5.6)%

Volume, exclusive of the effects of weather, remained relatively consistent for the three months ended March 31, 2021 compared to the same period in 2020.

Electric Retail Deliveries to Delaware Customers (in GWhs)	Three Months Ended March 31,		% Change	Weather - Normal % Change ^(b)
	2021	2020		
Residential	854	743	14.9 %	4.5 %
Small commercial & industrial	342	296	15.5 %	10.5 %
Large commercial & industrial	689	823	(16.3)%	(17.2)%
Public authorities & electric railroads	9	8	12.5 %	7.7 %
Total electric retail deliveries ^(a)	1,894	1,870	1.3 %	(3.6)%

Number of Total Electric Customers (Maryland and Delaware)	As of March 31,	
	2021	2020
Residential	473,917	469,082
Small commercial & industrial	62,647	61,769
Large commercial & industrial	1,208	1,414
Public authorities & electric railroads	608	612
Total	538,380	532,877

(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 mmcft)	Three Months Ended March 31,		% Change	Weather - Normal % Change ^(b)
	2021	2020		
Residential	4,394	3,647	20.5 %	2.6 %
Small commercial & industrial	1,868	1,671	11.8 %	(3.9)%
Large commercial & industrial	457	452	1.1 %	1.1 %
Transportation	2,224	2,108	5.5 %	(0.9)%
Total natural gas deliveries ^(a)	8,943	7,878	13.5 %	0.2 %

Number of Delaware Natural Gas Customers	As of March 31,	
	2021	2020
Residential	127,522	126,209
Small commercial & industrial	10,043	10,004
Large commercial & industrial	19	17
Transportation	160	159
Total	137,744	136,389

- (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, 2021 compared to the same period in 2020 primarily due to higher electric distribution rates in Maryland that became effective in July 2020 and higher electric and natural gas distribution rates in Delaware that became effective in the second half of 2020.

Transmission Revenues. 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.

Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, 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. Customers have the choice to purchase electricity from competitive electric generation 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 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 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 \$15 million for the three months ended March 31, 2021, compared to the same period in 2020, 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, 2021
	Increase (Decrease)
Labor, other benefits, contracting and materials	\$ 2
BSC and PHISCO costs	2
Credit loss expense	1
Pension and non-pension postretirement benefits expense	(1)
Total increase	\$ 4

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

	Three Months Ended March 31, 2021
	Increase
Depreciation and amortization ^(a)	\$ 3
Regulatory required programs	2
Total increase	\$ 5

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Effective income tax rates were 8.2% and 13.5% for the three months ended March 31, 2021 and 2020, respectively. See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

Results of Operations — ACE

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2021	2020	
Operating revenues	\$ 310	\$ 276	\$ 34
Operating expenses			
Purchased power expense	157	128	(29)
Operating and maintenance	76	78	2
Depreciation and amortization	47	43	(4)
Taxes other than income taxes	2	2	—
Total operating expenses	282	251	(31)
Gain on sale of assets	—	2	(2)
Operating income	28	27	1
Other income and (deductions)			
Interest expense, net	(15)	(15)	—
Other, net	1	2	(1)
Total other income and (deductions)	(14)	(13)	(1)
Income before income taxes	14	14	—
Income taxes	—	1	1
Net income	\$ 14	\$ 13	\$ 1

Three Months Ended March 31, 2021 Compared to Three Months Ended March 31, 2020. Net income remained relatively consistent.

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

	Three Months Ended March 31, 2021
	Increase (Decrease)
Weather	\$ 4
Volume	2
Distribution	(1)
Other	1
	6
Regulatory required programs	28
Total increase	\$ 34

Weather. The demand for electricity is affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. There was an increase related to weather for the three months ended March 31, 2021 compared to same period in 2020 due to the impact of favorable weather conditions in ACE’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 20-year period in ACE’s service territory. The changes in heating and cooling degree days in ACE’s service territory for the three months ended March 31, 2021 compared to same period in 2020 and normal weather consisted of the following:

Heating and Cooling Degree-Days	% Change					
	Three Months Ended March 31,	2021	2020	Normal	2021 vs. 2020	2021 vs. Normal
Heating Degree-Days		2,348	1,948	2,469	20.5 %	(4.9)%
Cooling Degree-Days		4	—	—	n/a	n/a

Volume, exclusive of the effects of weather, increased for the three months ended March 31, 2021 compared to the same period in 2020, primarily due to residential customer growth and usage, partially offset by lower commercial and industrial usage.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,		% Change	Weather - Normal % Change^(b)
	2021	2020		
Residential	928	810	14.6 %	6.6 %
Small commercial & industrial	305	294	3.7 %	(0.8)%
Large commercial & industrial	716	735	(2.6)%	(3.5)%
Public authorities & electric railroads	13	13	— %	0.9 %
Total electric retail deliveries^(a)	1,962	1,852	5.9 %	1.5 %

Number of Electric Customers	As of March 31,	
	2021	2020
Residential	498,396	495,444
Small commercial & industrial	61,771	61,470
Large commercial & industrial	3,267	3,355
Public authorities & electric railroads	704	684
Total	564,138	560,953

(a) Reflects delivery volumes from customers purchasing electricity directly from ACE 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.

Distribution Revenue remained relatively consistent for the three months ended March 31, 2021 compared to the same period in 2020.

Transmission Revenues. 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.

Other Revenue includes rental revenue, service connection fees, and mutual assistance revenues.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, Societal Benefits Charge, Transition Bonds, and BGS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, as ACE remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, ACE acts as the billing agent and therefore 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 REC.

See Note 5 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

The increase of \$29 million for the three months ended March 31, 2021 compared to the same period in 2020, 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, 2021
	Increase (Decrease)
Labor, other benefits, contracting and materials	\$ 1
BSC and PHISCO costs	1
	<u>2</u>
Regulatory required programs ^(a)	(4)
Total decrease	\$ (2)

(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, 2021
	Increase (Decrease)
Depreciation and amortization ^(a)	\$ 4
Regulatory asset amortization	(1)
Regulatory required programs	1
Total increase	\$ 4

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Gain on sale of assets for the three months ended March 31, 2021 compared to the same period in 2020 decreased due to the sale of land in the first quarter of 2020.

Effective income tax rates were 0.0% and 7.1% for the three months ended March 31, 2021 and 2020, respectively. See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

Liquidity and Capital Resources

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, the sale of certain receivables, 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, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). 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 \$10.6 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" section below for additional information. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. 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. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt and credit agreements.

NRC Minimum Funding Requirements (Exelon and Generation)

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are typically based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant's owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 8 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT funds could appreciate in value. A shortfall could require that Generation address the shortfall by providing additional financial assurances such as letters of credit or parent company guarantees for Generation's share of the funding assurance. However, the amount of any guarantees or other assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the NDT fund investment performance going forward. No later than two years after shutting down a plant, Generation must submit a PSDAR to the NRC that includes the planned option for decommissioning the site. Upon early retirement, Dresden will have adequate funding assurance, however, due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value, Byron may no longer meet the NRC minimum funding requirements and, as a result, additional financial assurance may be required. Considering the different approaches to decommissioning available to Generation, the most likely estimates currently anticipated could require financial assurance for radiological decommissioning at Byron of up to \$55 million.

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, under the regulations, the NRC must approve an exemption in order for Generation to utilize the

NDT funds to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs, if applicable). If a unit does not receive this exemption, those costs would be borne by Generation without reimbursement from or access to the NDT funds. Based on current projections of the most likely decommissioning approach and expected exemptions from the NRC, it is expected that Dresden would not require supplemental cash from Generation, but some portion of the Byron spent fuel management costs would need to be funded through supplemental cash from Generation. While the ultimate amounts may vary and could be offset by reimbursement of certain spent fuel management costs under the DOE settlement agreement, decommissioning for Byron may require supplemental cash from Generation of up to \$180 million, net of taxes, over a period of 10 years after permanent shutdown.

As of March 31, 2021, Generation is not required to provide any additional financial assurances for TMI Unit 1 under the SAFSTOR scenario which is the planned decommissioning option as described in the TMI Unit 1 PSDAR filed by Generation with the NRC on April 5, 2019. On October 16, 2019, the NRC granted Generation's exemption request to use the TMI Unit 1 NDT funds for spent fuel management costs. An additional exemption request would be required to allow the funds to be spent on site restoration costs, which are not expected to be incurred in the near term.

Project Financing (Exelon and Generation)

Project financing is used to help mitigate risk of specific generating assets. Project financing is based upon a nonrecourse financial structure, in which project debt is paid back from the cash generated by the specific asset or portfolio of assets. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, or restructured, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives. Additionally, project finance has credit facilities. Refer to Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on credit facilities and nonrecourse debt.

Cash Flows from Operating Activities (All Registrants)

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers and the sale of certain receivables.

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.

See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2020 Form 10-K 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, 2021 and 2020 by Registrant:

Decrease in cash flows from operating activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income	\$ (640)	\$ (608)	\$ 29	\$ 27	\$ 28	\$ 20	\$ 7	\$ 11	\$ 1
Adjustments to reconcile net income to cash:									
Non-cash operating activities	(484)	(391)	15	(6)	(18)	(8)	(1)	4	(7)
Pension and non-pension postretirement benefit contributions	(6)	27	(28)	—	(1)	(9)	(1)	—	(1)
Income taxes	169	3	(16)	(11)	(16)	(12)	(4)	(4)	(1)
Changes in working capital and other noncurrent assets and liabilities	(1,728)	(1,609)	(50)	(30)	(136)	(14)	(14)	(11)	6
Option premiums received (paid), net	54	54	—	—	—	—	—	—	—
Collateral received (posted), net	294	292	2	—	—	—	—	—	—
Decrease in cash flows from operating activities	\$ (2,341)	\$ (2,232)	\$ (48)	\$ (20)	\$ (143)	\$ (23)	\$ (13)	\$ —	\$ (2)

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. In addition, significant operating cash flow impacts for the Registrants for the three months ended March 31, 2021 and 2020 were as follows:

- See Note 17 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statement of Cash Flows for additional information on **non-cash operating activities**.
- See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statement of Cash Flows for additional information on **income taxes**.
- **Changes in working capital and other noncurrent assets and liabilities** are primarily due to impacts resulting from the sale of customer accounts receivable at Exelon and Generation. See Note 6 – Accounts Receivable for additional information.
- Depending upon whether Generation is in a net mark-to-market liability or asset position, **collateral** may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the over-the-counter markets.

Cash Flows from Investing Activities (All Registrants)

The following table provides a summary of the change in cash flows from investing activities for the three months ended March 31, 2021 and 2020 by Registrant:

Increase (decrease) in cash flows from investing activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	\$ (124)	\$ 176	\$ (107)	\$ (36)	\$ (53)	\$ (80)	\$ (40)	\$ (17)	\$ (22)
Proceeds from NDT fund sales, net	20	20	—	—	—	—	—	—	—
Proceeds from sales of assets and businesses	680	680	—	—	—	—	—	—	—
Changes in intercompany money pool	—	254	—	(26)	—	—	114	—	—
Collection of DPP	1,574	1,574	—	—	—	—	—	—	—
Other investing activities	20	6	2	—	8	—	5	4	(6)
Increase (decrease) in cash flows from investing activities	\$ 2,170	\$ 2,710	\$ (105)	\$ (62)	\$ (45)	\$ (80)	\$ 79	\$ (13)	\$ (28)

Significant investing cash flow impacts for the Registrants for three months ended March 31, 2021 and 2020 were as follows:

- Variances in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. Refer to Liquidity and Capital Resources of the Exelon 2020 Form 10-K for additional information on projected capital expenditure spending.

- See Note 2 – Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information related to the **sale** of a significant portion of Generation's solar business.
- Changes in **intercompany money pool** are driven by short-term borrowing needs. Refer to more information regarding the intercompany money pool below.
- See Note 6 – Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on the **Collection of DPP**.

Capital Expenditure Spending

As of March 31, 2021, there have been no material changes to the Registrants' projected capital expenditures as disclosed in Liquidity and Capital Resources of the Exelon 2020 Form 10-K.

Cash Flows from Financing Activities (All Registrants)

The following table provides a summary of the change in cash flows from financing activities for the three months ended March 31, 2021 and 2020 by Registrant:

Increase (decrease) in cash flows from financing activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	\$ 488	\$ 222	\$ (58)	\$ —	\$ 90	\$ (268)	\$ 47	\$(144)	\$(171)
Long-term debt, net	6	(508)	(300)	375	—	437	—	125	311
Changes in intercompany money pool	—	(285)	—	(40)	—	(4)	—	(37)	(77)
Dividends paid on common stock	(1)	—	(2)	—	(12)	—	—	12	9
Distributions to member	—	10	—	—	—	53	—	—	—
Contributions from parent/member	—	—	73	(231)	—	416	1	114	302
Other financing activities	(24)	(4)	4	(4)	—	(4)	—	(2)	(3)
Increase (decrease) in cash flows from financing activities	\$ 469	\$ (565)	\$ (283)	\$ 100	\$ 78	\$ 630	\$ 48	\$ 68	\$ 371

Significant financing cash flow impacts for the Registrants for the three months ended March 31, 2021 and 2020 were as follows:

- **Changes in short-term borrowings, net**, is driven by repayments on and issuances of notes due in less than 365 days. Refer to 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on short-term borrowings.
- **Long-term debt, net**, varies due to debt issuances and redemptions each year. Refer to 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on debt issuances. Refer to debt redemptions tables below for additional information.
- **Changes in intercompany money pool** are driven by short-term borrowing needs. Refer to more information regarding the intercompany money pool below.
- 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 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2020 Form 10-K for additional information on dividend restrictions. See below for quarterly dividends declared.
- For the three months ended March 31, 2021, other financing activities primarily consists of debt issuance costs. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' debt issuances.

Debt

See Note 12 — 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, 2021, the following long-term debt was retired and/or redeemed:

Company ^(a)	Type	Interest Rate	Maturity	Amount
Generation	Continental Wind Nonrecourse Debt ^(b)	6.00 %	February 28, 2033	\$ 19
Generation	SolGen Nonrecourse Debt ^(b)	3.93 %	September 30, 2036	6
Generation	Antelope Valley DOE Nonrecourse Debt ^(b)	2.29 % - 3.56 %	January 5, 2037	5
Generation	RPG Nonrecourse Debt ^(b)	4.11 %	March 31, 2035	3
Generation	EGR IV Nonrecourse Debt ^(b)	3 month LIBOR + 2.75 %	December 15, 2027	2
ACE	Tax-Exempt First Mortgage Bonds	6.80 %	March 1, 2021	39
ACE	Transition Bonds	5.55 %	October 20, 2021	5

(a) On April 15, 2021, Exelon Corporate redeemed \$300 million of 2.45% senior notes. On April 1, 2021, ACE redeemed \$200 million of 4.35% first mortgage bonds.

(b) See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on nonrecourse debt.

Dividends

Quarterly dividends declared by the Exelon Board of Directors during the three months ended March 31, 2021 and for the second quarter of 2021 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share ^(a)
First Quarter 2021	February 21, 2021	March 8, 2021	March 15, 2021	\$ 0.3825
Second Quarter 2021	April 27, 2021	May 14, 2021	June 10, 2021	\$ 0.3825

(a) Exelon’s Board of Directors approved an updated dividend policy for 2021. The 2021 quarterly dividend will remain the same as the 2020 dividend of \$0.3825 per share.

Credit Matters (All Registrants)

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 \$10.6 billion in aggregate total commitments of which \$6.9 billion was available to support additional commercial paper as of March 31, 2021, and of which no financial institution has more than 7% 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 first quarter of 2021 to fund their short-term liquidity needs, when necessary. Generation used its available credit facilities to manage short-term liquidity needs as a result of the impacts of the February 2021 extreme cold weather event and continues to believe it has sufficient cash on hand and available capacity on its revolver to meet its liquidity requirements. 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 Exelon 2020 Form 10-K for additional information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets, and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of March 31, 2021, it would have been required to provide incremental collateral of approximately \$1.4 billion to meet collateral obligations for derivatives, non-derivatives, normal purchases and normal sales contracts, and applicable

payables and receivables, net of the contractual right of offset under master netting agreements, which is well within the \$3.5 billion of available credit capacity of its revolver.

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, 2021 and available credit facility capacity prior to any incremental collateral at March 31, 2021:

	PJM Credit Policy Collateral	Other Incremental Collateral Required ^(a)	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	\$ 20	\$ —	\$ 863
PECO	14	32	600
BGE	3	48	444
Pepco	3	—	300
DPL	3	12	300
ACE	—	—	300

(a) Represents incremental collateral related to natural gas procurement contracts.

Exelon Credit Facilities

Exelon Corporate, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet 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 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 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' short-term borrowing activity. See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on the Registrants' credit facilities.

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 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

The credit ratings for Exelon Corporate and the Utility Registrants did not change for the three months ended March 31, 2021. On February 24, 2021, S&P lowered Generation's senior unsecured debt rating to 'BBB-' from 'BBB'.

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. The PHI intercompany money pool had no activity for the three months ended March 31, 2021. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of March 31, 2021, are presented in the following table:

	During the Three Months Ended March 31, 2021		As of March 31, 2021
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Intercompany Money Pool			
Exelon Corporate	\$ 735	\$ —	\$ 267
Generation	—	(426)	—
PECO	135	(100)	48
BSC	—	(432)	(346)
PHI Corporate	—	(40)	(24)
PCI	60	—	55

Shelf Registration Statements

Exelon, Generation, and the Utility Registrants have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2022. 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, 2021					
	Short-term Financing Authority ^(a)			Remaining Long-term Financing Authority ^(a)		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd ^(b)	FERC	December 31, 2021	\$ 2,500	ICC	2023 & 2024	\$ 543
PECO	FERC	December 31, 2021	1,500	PAPUC	December 31, 2021	850
BGE	FERC	December 31, 2021	700	MDPSC	N/A	1,100
Pepco	FERC	December 31, 2021	500	MDPSC / DCPSC	December 31, 2022	750
DPL	FERC	December 31, 2021	500	MDPSC / DPSC	December 31, 2022	172
ACE	NJBPU	December 31, 2021	350	NJBPU	December 31, 2022	250

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

(b) ComEd had \$350 million available in long-term debt refinancing authority and \$193 million available in new money long-term debt financing authority from the ICC as of March 31, 2021 and has an expiration date of February 1, 2024 and February 1, 2023, respectively.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Generation, ComEd, PECO, BGE, Pepco, DPL, and ACE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd and PECO have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements in the Exelon 2020 Form 10-K for additional information.

For an in-depth discussion of the Registrants' contractual obligations and off-balance sheet arrangements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Off-Balance Sheet Arrangements" in the Exelon 2020 Form 10-K and Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates, and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer, and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of Exelon's 2020 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk (All Registrants)

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 generates and 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, fossil fuel, and other commodities.

Generation

Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of the Utility Registrants' retail load, is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards, and options, with approved counterparties to hedge anticipated exposures. Generation uses derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2021 through 2023.

As of March 31, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% for 2021. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire economic hedge portfolio associated with a \$5 reduction in the annual average around-the-clock energy price based on March 31, 2021 market conditions and hedged position would be an increase in pre-tax net income of approximately \$31 million for 2021. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

Approximately 60% of Generation's uranium concentrate requirements from 2021 through 2025 are supplied by three suppliers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's financial statements.

Utility Registrants

There have been no significant changes or additions to the Utility Registrants exposures to commodity price risk that were described in ITEM 1A. RISK FACTORS of Exelon's 2020 Annual Report on Form 10-K. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding commodity price risk exposure.

Trading and Non-Trading Marketing Activities

The following table detailing Exelon's, Generation's, and ComEd's trading and non-trading marketing activities are included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon’s, Generation’s, and ComEd’s commodity mark-to-market net asset or liability balance sheet position from December 31, 2020 to March 31, 2021. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of March 31, 2021 and December 31, 2020.

	Exelon	Generation	ComEd
Total mark-to-market energy contract net assets (liabilities) at December 31, 2020 ^(a)	\$ 428	\$ 729	\$ (301)
Total change in fair value during 2021 of contracts recorded in results of operations	243	243	—
Reclassification to realized at settlement of contracts recorded in results of operations	(61)	(61)	—
Changes in fair value — recorded through regulatory assets ^(b)	6	—	6
Changes in allocated collateral	(270)	(270)	—
Net option premium paid	(16)	(16)	—
Option premium amortization	(17)	(17)	—
Upfront payments and amortizations ^(c)	(128)	(128)	—
Total mark-to-market energy contract net assets (liabilities) at March 31, 2021 ^(a)	<u>\$ 185</u>	<u>\$ 480</u>	<u>\$ (295)</u>

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) For ComEd, the changes in fair value are recorded as a change in regulatory assets. As of March 31, 2021, ComEd recorded a regulatory asset of \$295 million related to its mark-to-market derivative liabilities with unaffiliated suppliers. For the three months ended March 31, 2021, ComEd recorded \$2 million of decreases in fair value and an increase for realized losses due to settlements of \$8 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

(c) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation, and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants’ total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants’ commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 13 — 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.

Exelon

	Maturities Within						Total Fair Value
	2021	2022	2023	2024	2025	2026 and Beyond	
Normal Operations, Commodity derivative contracts ^{(a)(b)} :							
Actively quoted prices (Level 1)	\$ (27)	\$ (6)	\$ 14	\$ 16	\$ 18	\$ —	\$ 15
Prices provided by external sources (Level 2)	138	103	17	(1)	1	—	258
Prices based on model or other valuation methods (Level 3) ^(c)	(53)	95	42	(11)	(13)	(148)	(88)
Total	\$ 58	\$ 192	\$ 73	\$ 4	\$ 6	\$ (148)	\$ 185

- (a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
- (b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of \$169 million at March 31, 2021.
- (c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						Total Fair Value
	2021	2022	2023	2024	2025	2026 and Beyond	
Normal Operations, Commodity derivative contracts ^{(a)(b)} :							
Actively quoted prices (Level 1)	\$ (27)	\$ (6)	\$ 14	\$ 16	\$ 18	\$ —	\$ 15
Prices provided by external sources (Level 2)	138	103	17	(1)	1	—	258
Prices based on model or other valuation methods (Level 3)	(29)	124	71	17	15	9	207
Total	\$ 82	\$ 221	\$ 102	\$ 32	\$ 34	\$ 9	\$ 480

- (a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
- (b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of \$169 million at March 31, 2021.

ComEd

	Maturities Within						Total Fair Value
	2021	2022	2023	2024	2025	2026 and Beyond	
Commodity derivative contracts ^(a) :							
Prices based on model or other valuation methods (Level 3) ^(a)	\$ (24)	\$ (29)	\$ (29)	\$ (28)	\$ (28)	\$ (157)	\$ (295)

- (a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for detailed discussion of credit risk.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchases and normal sales agreements, and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of March 31, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The amounts in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, and commodity exchanges, which are discussed below.

Rating as of March 31, 2021	Total Exposure Before Credit Collateral	Credit Collateral ^(a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	\$ 431	\$ 31	\$ 400	—	\$ —
Non-investment grade	43	4	39		
No external ratings					
Internally rated — investment grade	146	1	145		
Internally rated — non-investment grade	70	25	45		
Total	<u>\$ 690</u>	<u>\$ 61</u>	<u>\$ 629</u>	<u>—</u>	<u>\$ —</u>

Rating as of March 31, 2021	Maturity of Credit Risk Exposure			Total Exposure Before Credit Collateral
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	
Investment grade	\$ 332	\$ 52	\$ 47	\$ 431
Non-investment grade	43	—	—	43
No external ratings				
Internally rated — investment grade	109	25	12	146
Internally rated — non-investment grade	48	16	6	70
Total	<u>\$ 532</u>	<u>\$ 93</u>	<u>\$ 65</u>	<u>\$ 690</u>

Net Credit Exposure by Type of Counterparty	As of March 31, 2021
Investor-owned utilities, marketers, power producers	\$ 451
Energy cooperatives and municipalities	123
Other	55
Total	<u>\$ 629</u>

(a) As of March 31, 2021, credit collateral held from counterparties where Generation had credit exposure included \$32 million of cash and \$29 million of letters of credit.

The Utility Registrants

There have been no significant changes or additions to the Utility Registrants exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2020 Annual Report on Form 10-K. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding credit exposure to suppliers.

Credit-Risk-Related Contingent Features (All Registrants)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas, and other commodities. In accordance with the contracts and

applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, 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. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements. See Note 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's financial statements. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. To post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 17 — Debt and Credit Agreements of Exelon's 2020 Annual Report on Form 10-K for additional information.

Utility Registrants

As of March 31, 2021, the Utility Registrants were not required to post collateral under their energy and/or natural gas procurement contracts. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Interest Rate and Foreign Exchange Risk (Exelon and Generation)

Exelon and Generation use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Exelon and Generation may also utilize interest rate swaps to manage their interest rate exposure. A hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an immaterial decrease in Exelon pre-tax income for the three months ended March 31, 2021. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of March 31, 2021, Generation's NDT funds are reflected at fair value in its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 25 basis points increase in interest rates and 10% decrease in equity prices would result in a \$844 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices.

ITEM 4. CONTROLS AND PROCEDURES

During the first quarter of 2021, 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 Exelon'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, 2021, 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 2021 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 Exelon's 2020 Form 10-K and (b) Notes 3 — Regulatory Matters and 14 — 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, 2021, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2020 Form 10-K in ITEM 1A. RISK FACTORS.

ITEM 4. MINE SAFETY DISCLOSURES

All Registrants

Not applicable to the Registrants.

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.

Exhibit No.	Description
4.1	One Hundred and Nineteenth Supplemental Indenture, dated as of February 15, 2021, from PECO to U.S. Bank National Association, as trustee (File No. 000-16844, Form 8-K dated March 8, 2021, Exhibit 4.1)
4.2	Supplemental Indenture, dated as of February 16, 2021, from ComEd to BNY Mellon Trust Company of Illinois, as trustee, and D.G. Donovan, as co-trustee (File No. 001-01839, Form 8-K dated March 9, 2021, Exhibit 4.1)
4.3	ACE Indenture Supplemental to Mortgage and Deed of Trust, dated as of February 15, 2021 (File No. 001-03559, Form 8-K dated March 10, 2021, Exhibit 4.1)
4.4	DPL Supplemental Indenture to the Mortgage and Deed of Trust, dated as of February 15, 2021 (File No. 001-01405, Form 8-K dated March 30, 2021, Exhibit 4.2)
4.5	Pepco Supplemental Indenture to the Mortgage and Deed of Trust, dated as of February 15, 2021 (File No. 001-01072, Form 8-K dated March 30, 2021, Exhibit 4.4)
4.6*	One Hundred and Twenty-Eighth Supplemental Indenture, dated January 1, 2021, between DPL and the Bank of New York, as trustee
10.1	Amendment No. 2 to Receivables Purchase Agreement, dated as of March 29, 2021, among Constellation NewEnergy, Inc., as servicer, and NewEnergy Receivables LLC, as seller, MUFG Bank, LTD., as agent, the Conduits party thereto, the Financial Institutions party thereto and the Purchaser Agents party thereto (File No. 001-16169, Form 8-K, dated March 31, 2021, Exhibit 10.1)
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)

*Filed herewith

[Table of Contents](#)

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, 2021 filed by the following officers for the following companies:

Exhibit No.	Description
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Joseph Nigro for Exelon Corporation
31-3	Filed by Christopher M. Crane for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Joseph Dominguez for Commonwealth Edison Company
31-6	Filed by Jeanne M. Jones for Commonwealth Edison Company
31-7	Filed by Michael A. Innocenzo for PECO Energy Company
31-8	Filed by Robert J. Stefani for PECO Energy Company
31-9	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
31-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
31-11	Filed by David M. Velazquez for Pepco Holdings LLC
31-12	Filed by Phillip S. Barnett for Pepco Holdings LLC
31-13	Filed by David M. Velazquez for Potomac Electric Power Company
31-14	Filed by Phillip S. Barnett for Potomac Electric Power Company
31-15	Filed by David M. Velazquez for Delmarva Power & Light Company
31-16	Filed by Phillip S. Barnett for Delmarva Power & Light Company
31-17	Filed by David M. Velazquez for Atlantic City Electric Company
31-18	Filed by Phillip S. Barnett for Atlantic City Electric Company

[Table of Contents](#)

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, 2021 filed by the following officers for the following companies:

Exhibit No.	Description
32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Joseph Nigro for Exelon Corporation
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32-16	Filed by Phillip S. Barnett for Delmarva Power & Light Company
32-17	Filed by David M. Velazquez for Atlantic City Electric Company
32-18	Filed by Phillip S. Barnett for Atlantic City Electric Company

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/ CHRISTOPHER M. CRANE

Christopher M. Crane

President, Chief Executive Officer
(Principal Executive Officer) and Director

/s/ JOSEPH NIGRO

Joseph Nigro

Senior Executive Vice President and Chief Financial
Officer
(Principal Financial Officer)

/s/ FABIAN E. SOUZA

Fabian E. Souza

Senior Vice President and Corporate Controller
(Principal Accounting Officer)

May 5, 2021

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 GENERATION COMPANY, LLC

 /s/ CHRISTOPHER M. CRANE

Christopher M. Crane
Principal Executive Officer

 /s/ BRYAN P. WRIGHT

Bryan P. Wright
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

 /s/ MATTHEW N. BAUER

Matthew N. Bauer
Vice President and Controller
(Principal Accounting Officer)

May 5, 2021

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/ JOSEPH DOMINGUEZ

Joseph Dominguez
Chief Executive Officer
(Principal Executive Officer)

 /s/ JEANNE M. JONES

Jeanne M. Jones
Senior Vice President, Chief Financial Officer and
Treasurer
(Principal Financial Officer)

 /s/ STEVEN J. CICHOCKI

Steven J. Cichocki
Director, Accounting
(Principal Accounting Officer)

May 5, 2021

Pursuant to requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

 /s/ MICHAEL A. INNOCENZO

Michael A. Innocenzo

President, Chief Executive Officer
(Principal Executive Officer)

 /s/ ROBERT J. STEFANI

Robert J. Stefani

Senior Vice President, Chief Financial Officer and
Treasurer
(Principal Financial Officer)

 /s/ CAROLINE FULGINITI

Caroline Fulginiti

Director, Accounting
(Principal Accounting Officer)

May 5, 2021

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
Chief Executive Officer
(Principal Executive Officer)

 /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 5, 2021

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/ DAVID M. VELAZQUEZ

David M. Velazquez

President, Chief Executive Officer
(Principal Executive Officer)

 /s/ PHILLIP S. BARNETT

Phillip S. Barnett

Senior Vice President, Chief Financial Officer and
Treasurer
(Principal Financial Officer)

 /s/ JULIE E. GIESE

Julie E. Giese

Director, Accounting
(Principal Accounting Officer)

May 5, 2021

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/ DAVID M. VELAZQUEZ

David M. Velazquez

President and Chief Executive Officer
(Principal Executive Officer)

/s/ PHILLIP S. BARNETT

Phillip S. Barnett

Senior Vice President, Chief Financial Officer and
Treasurer
(Principal Financial Officer)

/s/ JULIE E. GIESE

Julie E. Giese

Director, Accounting
(Principal Accounting Officer)

May 5, 2021

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/ DAVID M. VELAZQUEZ

David M. Velazquez

President and Chief Executive Officer
(Principal Executive Officer)

 /s/ PHILLIP S. BARNETT

Phillip S. Barnett

Senior Vice President, Chief Financial Officer and
Treasurer
(Principal Financial Officer)

 /s/ JULIE E. GIESE

Julie E. Giese

Director, Accounting
(Principal Accounting Officer)

May 5, 2021

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/ DAVID M. VELAZQUEZ

David M. Velazquez

President and Chief Executive Officer
(Principal Executive Officer)

 /s/ PHILLIP S. BARNETT

Phillip S. Barnett

Senior Vice President, Chief Financial Officer and
Treasurer
(Principal Financial Officer)

 /s/ JULIE E. GIESE

Julie E. Giese

Director, Accounting
(Principal Accounting Officer)

May 5, 2021

**BEFORE THE
PUBLIC SERVICE COMMISSION
OF MARYLAND**

**AFFIDAVIT OF
JULIE E. GIESE**

I, Julie E. Giese, am the Director, Accounting (Principal Accounting Officer) of Pepco Holdings LLC, a public utility holding company for Delmarva Power & Light Company (Delmarva) and Potomac Electric Power Company (Pepco). I hereby certify that to the best of my knowledge, information and belief, Delmarva and Pepco in good faith follow the processes and procedures set forth in the Pepco Holdings LLC Cost Allocation Manual (CAM) as well as the Commission's Asset Transfer policies contained in the Code of Maryland Regulations (COMAR) 20.40.02.05.

s/Julie E. Giese

Julie E. Giese

April 29, 2021

Date

My Commission expires _____