

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

delmarva.com

May 26, 2020

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, 2019 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 2019 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 2019 Annual Report/Maryland Jurisdictional Electric Sales Statistics.
3. One (1) copy of the report of Energy Taxes and Property Taxes paid in 2019 to each municipal, county and state agency in Maryland.
4. One (1) copy of the Exelon First Quarter 2020 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) 231-2174.

Sincerely,

David Weiss, CPA
Senior Manager, External Financial Reporting, Exelon
10 S. Dearborn, Chicago, IL 60603
David.Weiss@exeloncorp.com

Enclosures

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No. _____

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)



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 2019/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

IDENTIFICATION

01 Exact Legal Name of Respondent Delmarva Power & Light Company		02 Year/Period of Report End of <u>2019/Q4</u>
03 Previous Name and Date of Change <i>(if name changed during year)</i> / /		
04 Address of Principal Office at End of Period <i>(Street, City, State, Zip Code)</i> 500 North Wakefield Drive, Newark, Delaware 19702		
05 Name of Contact Person Robert Aiken		06 Title of Contact Person Vice President & Controller
07 Address of Contact Person <i>(Street, City, State, Zip Code)</i> 630 Martin Luther King Blvd, Wilmington, Delaware 19801		
08 Telephone of Contact Person, <i>Including Area Code</i> (302) 429-3359	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report <i>(Mo, Da, Yr)</i> 03/27/2020

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 <i>(Mo, Da, Yr)</i> 03/27/2020
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	

Name of Respondent
Delmarva Power & Light Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
03/27/2020

Year/Period of Report
End of 2019/Q4

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	
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 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) 03/27/2020	Year/Period of Report End of <u>2019/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 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) 03/27/2020	Year/Period of Report End of <u>2019/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, 2019, Delmarva Power & Light Company is controlled by Pepco Holdings LLC. Pepco Holdings LLC 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, 2019.

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.	606,211
2	Sr. Vice President and Chief Operating Officer	Anthony, J. Tyler	412,000
3	Sr. Vice President, Chief Financial Officer & Treasurer	Barnett, Phillip S.	394,180
4	Sr. Vice President, Governmental & External Affairs	Lavinson, Melissa	386,250
5	Sr. Vice President, Legal and Regulatory Strategy	Stark, Wendy E.	333,125
6	and General Counsel		
7	Vice President, Regulatory Policy and Strategy	McGowan, Kevin M.	330,000
8	Vice President and Controller	Aiken, Robert M.	310,140
9	Corporate Secretary	O'Neill, Thomas	538,125
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14	Listed officers are employees of PHI Service Company		
15	or Exelon Business Services Company LLC; salary for		
16	year represents the executive's annual base salary		
17	as of December 31, 2019 and only a portion of their		
18	annual base salary is allocated to DPL.		
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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	Pramaggiore, Anne R. ***	701 Ninth Street, N.W., Washington, D.C. 20068
2	Chairman and Director	
3		
4	Butler, Calvin G. ***	701 Ninth Street, N.W., Washington, D.C. 20068
5	Chairman and Director	
6		
7	Velazquez, David M.	701 Ninth Street, N.W., Washington, D.C. 20068
8	Director	
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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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

Schedule Page: 105 Line No.: 1 Column: a
 Effective October 15, 2019, Anne R. Pramaggiore retired from her role of Chairman and Director.

Schedule Page: 105 Line No.: 4 Column: a
 Effective November 15, 2019, Calvin G. Butler assumed the role of Chairman and Director.

Name of Respondent
Delmarva Power & Light Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
03/27/2020

Year/Period of Report
End of 2019/Q4

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-1A of PJM OATT	ER05-515
2	Attachment H-1A of PJM OATT	ER08-10, incentive filing
3	Attachment H-1A of PJM OATT	ER08-686, incentive filing
4	Attachment H-1A of PJM OATT	ER08-1423, incentive filing
5	Attachment H-1A of PJM OATT	EL13-48, ROE
6	Attachment H-1A of PJM OATT	ER19-6, FAS 109
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Name of Respondent
Delmarva Power & Light Company

This Report Is:
(1) An Original
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Date of Report
(Mo, Da, Yr)
03/27/2020

Year/Period of Report
End of 2019/Q4

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	20190515-5169	05/15/2019	ER09-1158	Informational Filing of Annual Formula	
2					
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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	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 03/27/2020	Year/Period of Report End of <u>2019/Q4</u>
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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 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) 03/27/2020	Year/Period of Report 2019/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

IMPORTANT CHANGES DURING THE QUARTER/YEAR

This information is for changes in the year ended December 31, 2019.

Item 1	None
Item 2	None
Item 3	None
Item 4	None
Item 5	None
Item 6	Refer to Note 8, "Debt" 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 order number 9525 and Maryland Public Service Commission 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 10, "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 changes below:
Item 14	DPL participates in a cash management program. As of December 31, 2019, DPL's proprietary capital ratio is greater than 30 percent.

Response to Item 13
above:

<u>Name</u>	<u>Executive Officer Position</u>	<u>Action and Date</u>
Anne R. Pramaggiore	Chairman and Director	RESIGN - 10/15/19
Calvin G. Butler	Chairman and Director	ELECT - 11/15/2019

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	5,371,631,253	5,034,659,642
3	Construction Work in Progress (107)	200-201	125,378,143	151,444,729
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,497,009,396	5,186,104,371
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,477,597,220	1,381,187,619
6	Net Utility Plant (Enter Total of line 4 less 5)		4,019,412,176	3,804,916,752
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)		4,019,412,176	3,804,916,752
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	13,916,770
19	(Less) Accum. Prov. for Depr. and Amort. (122)		4,430,033	4,378,893
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)		475,049	653,829
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)		10,013,783	10,191,706
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		12,448,546	8,641,814
36	Special Deposits (132-134)		305	1,100,574
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		329,194	14,664,218
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		91,803,458	88,638,440
41	Other Accounts Receivable (143)		40,230,363	43,897,314
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		14,626,712	12,701,997
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		122,848	218,636
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	44,642,941	37,490,617
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	8,787,093	8,103,320

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)		6,872,547	7,392,902
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		1,609,136	1,193,666
57	Prepayments (165)		18,471,567	17,480,714
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		45,208	622
60	Rents Receivable (172)		1,031,368	1,031,368
61	Accrued Utility Revenues (173)		61,127,012	59,266,575
62	Miscellaneous Current and Accrued Assets (174)		1,741,870	2,356,328
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)		274,636,744	278,775,111
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		12,414,416	12,653,169
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	176,322,478	196,654,254
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	173,825,745	188,543,578
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)		5,464,330	6,506,178
82	Accumulated Deferred Income Taxes (190)	234	198,093,922	223,225,419
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		566,120,891	627,582,598
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,870,183,594	4,721,466,167

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

Schedule Page: 110 Line No.: 2 Column: c

Accounts 101.1, 111, 227 and 243 include \$10,990,881, \$938,022, \$8,620,632 and \$1,432,227, respectively, related to new vehicle and equipment leases in 2019 that qualify as capital leases under the new leasing standard implemented as of January 1, 2019.

Schedule Page: 110 Line No.: 5 Column: c

Accounts 101.1, 111, 227 and 243 include \$10,990,881, \$938,022, \$8,620,632 and \$1,432,227, respectively, related to new vehicle and equipment leases in 2019 that qualify as capital leases under the new leasing standard implemented as of January 1, 2019.

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	448,555,442	385,896,940
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	602,118,249	593,221,255
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)		1,576,186,108	1,504,630,612
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,557,230,000	1,482,230,000
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	22,000,000
22	Unamortized Premium on Long-Term Debt (225)		2,634,428	3,103,748
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,380,567	1,438,567
24	Total Long-Term Debt (lines 18 through 23)		1,568,483,861	1,505,895,181
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		8,620,632	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		5,850,520	7,599,969
29	Accumulated Provision for Pensions and Benefits (228.3)		18,514,393	20,018,094
30	Accumulated Miscellaneous Operating Provisions (228.4)		276,213	670,027
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)		11,870,625	10,752,867
35	Total Other Noncurrent Liabilities (lines 26 through 34)		45,132,383	39,040,957
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		55,995,943	0
38	Accounts Payable (232)		99,578,447	99,800,080
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		32,398,374	32,837,898
41	Customer Deposits (235)		35,555,431	35,476,721
42	Taxes Accrued (236)	262-263	14,107,560	3,976,020
43	Interest Accrued (237)		7,742,554	8,019,399
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)		414,358	406,613
48	Miscellaneous Current and Accrued Liabilities (242)		41,201,993	41,071,627
49	Obligations Under Capital Leases-Current (243)		1,432,227	0
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)		288,426,887	221,588,358
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		7,907,288	9,692,270
57	Accumulated Deferred Investment Tax Credits (255)	266-267	2,004,132	2,350,600
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	22,840,731	21,337,755
60	Other Regulatory Liabilities (254)	278	507,596,758	568,072,353
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)		754,148,951	740,492,579
64	Accum. Deferred Income Taxes-Other (283)		97,456,495	108,365,502
65	Total Deferred Credits (lines 56 through 64)		1,391,954,355	1,450,311,059
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,870,183,594	4,721,466,167

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

Schedule Page: 112 Line No.: 26 Column: c
Accounts 101.1, 111, 227 and 243 include \$10,990,881, \$938,022, \$8,620,632 and \$1,432,227, respectively, related to new vehicle and equipment leases in 2019 that qualify as capital leases under the new leasing standard implemented as of January 1, 2019.

Schedule Page: 112 Line No.: 49 Column: c
Accounts 101.1, 111, 227 and 243 include \$10,990,881, \$938,022, \$8,620,632 and \$1,432,227, respectively, related to new vehicle and equipment leases in 2019 that qualify as capital leases under the new leasing standard implemented as of January 1, 2019.

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	1,319,054,785	1,346,724,607		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	793,197,500	823,572,993		
5	Maintenance Expenses (402)	320-323	71,766,942	69,450,351		
6	Depreciation Expense (403)	336-337	138,436,455	130,416,438		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,751,967	511,847		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	1,853,960	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)		24,821,486	63,357,835		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	56,061,850	55,521,339		
15	Income Taxes - Federal (409.1)	262-263	29,384,121	-1,337,606		
16	- Other (409.1)	262-263	6,940	-87,017		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	61,390,832	102,449,945		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	68,440,831	77,530,284		
19	Investment Tax Credit Adj. - Net (411.4)	266	-346,468	-394,236		
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)		1,114,884,754	1,167,785,565		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		204,170,031	178,939,042		

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)	
1,151,304,259	1,165,515,872	167,750,526	181,208,735			2
						3
675,517,798	692,993,035	117,679,702	130,579,958			4
65,081,265	61,944,361	6,685,677	7,505,990			5
127,027,779	119,169,871	11,408,676	11,246,567			6
						7
5,834,311	511,847	917,656				8
1,853,960	1,853,960					9
						10
						11
23,230,251	61,993,677	1,591,235	1,364,158			12
						13
46,561,814	46,067,973	9,500,036	9,453,366			14
25,933,274	-3,270,682	3,450,847	1,933,076			15
6,246	-78,315	694	-8,702			16
54,211,552	91,010,064	7,179,280	11,439,881			17
61,168,812	68,387,344	7,272,019	9,142,940			18
-305,466	-351,337	-41,002	-42,899			19
						20
						21
						22
						23
						24
963,783,972	1,003,457,110	151,100,782	164,328,455			25
187,520,287	162,058,762	16,649,744	16,880,280			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)		204,170,031	178,939,042		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		3,428,980	4,735,364		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		3,056,289	7,035,299		
33	Revenues From Nonutility Operations (417)		67,614	48,064		
34	(Less) Expenses of Nonutility Operations (417.1)		470,328	110,957		
35	Nonoperating Rental Income (418)		3,145,995	-525,332		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		432,921	1,459,504		
38	Allowance for Other Funds Used During Construction (419.1)		3,978,538	2,439,758		
39	Miscellaneous Nonoperating Income (421)		1,414,392	2,588,487		
40	Gain on Disposition of Property (421.1)			736,996		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		8,941,823	4,336,585		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		10,561			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		707,166	512,511		
46	Life Insurance (426.2)					
47	Penalties (426.3)		253,177	92,535		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		560,611	491,163		
49	Other Deductions (426.5)		2,510,225	4,828,572		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		4,041,740	5,924,781		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	688,279	673,145		
53	Income Taxes-Federal (409.2)	262-263	-587,347	-1,149,577		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	3,378,163	683,217		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,493,219	804,864		
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)		985,876	-598,079		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		3,914,207	-990,117		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		58,827,558	54,701,053		
63	Amort. of Debt Disc. and Expense (428)		981,675	947,480		
64	Amortization of Loss on Reaquired Debt (428.1)		1,041,847	1,167,916		
65	(Less) Amort. of Premium on Debt-Credit (429)		469,320	453,870		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		175,224	-17,976		
68	Other Interest Expense (431)		2,092,127	3,812,175		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,961,867	2,378,380		
70	Net Interest Charges (Total of lines 62 thru 69)		60,687,244	57,778,398		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		147,396,994	120,170,527		
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)		147,396,994	120,170,527		

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		593,221,255	569,500,728
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)		147,396,994	120,170,527
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			-138,500,000	(96,450,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-138,500,000	(96,450,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		602,118,249	593,221,255
	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)		602,118,249	593,221,255
	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)

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)	147,396,994	120,170,527
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	138,436,455	130,416,438
5	Amortization of regulatory debits/credits and limited plant	31,573,453	63,869,682
6	Plant Acquisition	1,853,960	1,853,960
7	Unamortized Discount (Premium) on Long-Term Debt	1,510,581	1,455,111
8	Deferred Income Taxes (Net)	-6,177,392	24,659,194
9	Investment Tax Credit Adjustment (Net)	-346,468	-394,236
10	Net (Increase) Decrease in Receivables	-3,244,301	21,973,318
11	Net (Increase) Decrease in Inventory	-7,047,439	-3,183,168
12	Net (Increase) Decrease in Allowances Inventory	-683,773	-153,578
13	Net Increase (Decrease) in Payables and Accrued Expenses	265,450	-5,906,566
14	Net (Increase) Decrease in Other Regulatory Assets	-4,489,710	-46,033,432
15	Net Increase (Decrease) in Other Regulatory Liabilities	-26,419,341	24,453,642
16	(Less) Allowance for Other Funds Used During Construction	3,978,538	2,439,758
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Pension	15,037,502	8,053,072
19	Other Operating Activities	275,081	12,771,271
20	Interest and Taxes Accrued	9,854,695	199,683
21	Gain on Sale of Assets	10,561	-631,874
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	293,827,770	351,133,286
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-351,956,277	-366,299,095
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	-3,978,538	-2,439,758
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-347,977,739	-363,859,337
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			655,013
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	Change in restricted cash	1,100,269	-1,100,012
54	Other Investing Activities	8,263	1,521,041
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-346,869,207	-362,783,295
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	75,000,000	200,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	55,995,943	
67	Other (provide details in footnote):		
68	Capital Contribution from Parent	62,658,502	150,700,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	193,654,445	350,700,000
71	Cost of Issuances	-641,300	-1,761,348
72	Payments for Retirement of:		
73	Long-term Debt (b)	-12,000,000	-4,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		-215,973,783
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-138,500,000	-96,450,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	42,513,145	32,514,869
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-10,528,292	20,864,860
87			
88	Cash and Cash Equivalents at Beginning of Period	23,306,032	2,441,172
89			
90	Cash and Cash Equivalents at End of period	12,777,740	23,306,032

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

Schedule Page: 120 Line No.: 13 Column: c

The amount presented in this report for the 2018 period contains amounts previously disclosed in the 2018 Form 1 on line 19 as "Other Operating Activities".

	2018
Asset Retirement Obligation	\$ (826,685)
Increase in Accumulated Provisions for Injuries and Damages	1,459,495
Decrease in Accumulated Provisions for Pensions and Benefits	(1,665,906)
Decrease in Accumulated Miscellaneous Operating Provision	(51,255)
Total Other Working Capital	\$ (1,084,351)

Schedule Page: 120 Line No.: 18 Column: c

The amount presented in this report for the 2018 period contains pension of \$8,053,072 previously disclosed in the 2018 Form 1 on line 19 as "Other Operating Activities".

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

Other Operating Activities:

	2019	2018
Net increase in Prepayments	\$ (990,853)	\$ (1,051,443)
Net decrease in Miscellaneous long term assets and deferred debits	544,788	(513,720)
Net decrease in Other deferred credits	1,502,976	(1,200,979)
Other	(781,830)	15,537,413
Total Other Operating Activities	\$ 275,081	\$ 12,771,271

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

Other Investing Activities:

	2019	2018
Re-capitalized Fleet Depreciation	\$ 1,272,562	\$ 1,215,480
Other	(1,264,299)	305,561
Total Other Investing Activities	\$ 8,263	\$ 1,521,041

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 03/27/2020	Year/Period of Report End of <u>2019/Q4</u>
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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) 03/27/2020	Year/Period of Report 2019/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, 2019. 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, 2019 and 2018 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, 2018 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, 2018 FERC Form No. 1 "Annual Report of Major Electric Utilities, Licensees and Others" (FERC Form No. 1).

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 benefits, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, 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

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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 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 Consolidated Balance Sheets. See Note 2 — Regulatory Matters and Note 7 — 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 gas and electricity. 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 12 - Supplemental Financial Information for DPL's utility taxes that are presented on a gross basis.

Income Taxes

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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 or Other income and deductions (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, 2019, and 2018, 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.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts reflects DPL's best estimates of losses on the customers' accounts receivable balances. DPL estimates the allowance by applying loss rates developed specifically for DPL to the outstanding receivable balance by customer risk segment. DPL's customer accounts are written off consistent with approved regulatory requirements.

Inventories

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory. Materials and supplies are generally included in inventory when purchased. 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. DOE SGIG and other funds reimbursed to DPL have

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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 Costs. 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.

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

See Note 3 - Property, Plant and Equipment and Note 12 - 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 3 - 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 Statements of Income.

See Note 2 - Regulatory Matters and Note 12 - Supplemental Financial Information for additional information regarding the amortization of DPL's regulatory assets.

Asset Retirement Obligations

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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 4 - Asset Retirement Obligations for additional information.

Guarantees

DPL recognizes, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken by issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced 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 10 - Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets. DPL regularly monitor and evaluate 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 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.

Normal purchases and normal sales 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 normal purchases and normal sales 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 7 - Derivative Financial Instruments for further information.

Retirement Benefits

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

The measurement of 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 other postretirement benefit obligations is recognized over time rather than immediately

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recognized in the Statement of Income. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 6 - Retirement Benefits for additional information.

New Accounting Pronouncements

New Accounting Standards Adopted in 2019

In 2019, DPL adopted the following new authoritative accounting guidance issued by the Financial Accounting Standards Board (FASB).

Cloud Computing Arrangements. Aligns the requirements for capitalizing costs incurred to implement a cloud computing arrangement with the internal-use software guidance. As a result, certain implementation costs incurred in a cloud computing arrangement that are currently expensed as incurred will be deferred and amortized over the non-cancellable term of the arrangement plus any reasonably certain renewal periods. DPL early adopted this standard using a prospective approach. The guidance was not adopted for FERC reporting purposes and resulted in no change to the financial statements.

Leases. DPL applied the new guidance with the following transition practical expedients for GAAP reporting purposes:

- 1 a "package of three" expedients that must be taken together and allow entities to (1) not reassess whether existing contracts contain leases, (2) carry forward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases,
- 2 an implementation expedient which allows the requirements of the standard in the period of adoption with no restatement of prior periods, and
- 3 a land easement expedient which allows entities to not evaluate land easements under the new standard at adoption if they were not previously accounted for as leases.

The guidance was not adopted for FERC reporting purposes and resulted in no change to the financial statements.

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 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 credit losses 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 test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be

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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 test). 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 will apply the new guidance for their goodwill impairment assessments in 2020 and do not expect the updated guidance to have a material impact to their 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 table shows the pending distribution base rate case proceedings in 2019.

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
DPL - Maryland (Electric)	December 5, 2019	\$ 19	10.3%	Third quarter of 2020

Transmission Formula Rates

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 formula rate 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 2019, the following total increases were included in DPL's electric transmission formula rate filing:

Registrant	Initial Revenue Requirement Increase	Annual Reconciliation (Decrease)	Total Revenue Requirement Increase	Allowed Return on Rate Base(a)	Allowed ROE(b)
DPL	\$ 17	\$ (1)	\$ 16	7.14 %	10.50 %

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

(b) As part of the FERC-approved settlement of the 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 RTO.

Other State Regulatory Matters

Maryland Regulatory Matters

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Maryland Alternative Rate Plans Rulemaking. On August 9, 2019, the MDPSC issued an order in which the MDPSC determined that it is now appropriate to move forward to implement alternative rate plans in Maryland. The MDPSC found that a multi-year rate plan, based on a historic test year and allowing up to three future test years, can produce just and reasonable rates. A working group was convened and submitted a detailed implementation report related to multi-year rate plans to the MDPSC on December 20, 2019. In response to the working group report, the MDPSC issued an order on February 4, 2020 establishing a multi-year rate plan pilot and an associated framework for a Maryland utility to use in the pilot multi-year rate plan filing. The working group was required to continue and discuss how best to integrate performance-based measures into a multi-year rate plan. The working group is currently discussing performance-based measures which could be combined with future multi-year rate plans and will submit its report to the MDPSC by April 1, 2020. DPL cannot predict the outcome or the potential financial impact, if any, on DPL.

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. DPL had similar transmission-related income tax regulatory liabilities and assets also requiring FERC approval. 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. As a result of the FERC's order, DPL took a charge to income tax expense within their Consolidated Statements of Operations and Comprehensive Income in the fourth quarter of 2017, reducing their associated transmission-related income tax regulatory assets for the portion of the total transmission-related income tax regulatory assets that would have been previously amortized and recovered through rates.

On December 18, 2017, BGE filed for clarification and rehearing of FERC's November 16, 2017 order and on February 23, 2018 (as amended on July 9, 2018), DPL filed with FERC to revise their transmission formula rate mechanisms to facilitate passing back to customers ongoing annual TCJA tax savings and 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 BGE's December 18, 2017 request for rehearing and clarification and DPL's February 23, 2018 (as amended on July 9, 2018) filings, citing the lack of timeliness of the requests to recover amounts that would have been previously amortized, but indicating that ongoing recovery of certain transmission-related income tax regulatory assets would provide for a more accurate revenue requirement, consistent with its November 16, 2017 order.

On October 1, 2018, DPL submitted a new filing to recover ongoing non-TCJA amortization amounts and refund TCJA transmission-related income tax regulatory liabilities for the prospective period starting on October 1, 2018. In addition, on October 9, 2018, DPL sought rehearing of FERC's September 7, 2018 order. On November 2, 2018, BGE filed an appeal of FERC's September 7, 2018 order to the Court of Appeals for the D.C. Circuit. On April 26, 2019, FERC issued an order accepting DPL's October 1, 2018 filings, effective October 1, 2018, subject to refund and established hearing and settlement judge procedures. DPL cannot predict the outcome of these proceedings.

If FERC ultimately rules that the future, ongoing non-TCJA amortization amounts are not recoverable, DPL would record additional charges to Income tax expense, which could be up to approximately \$5 million as of December 31, 2019.

PJM Transmission Rate Design. On June 15, 2016, several parties, including DPL, filed a proposed settlement with FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. The settlement included provisions for monthly credits or charges related to the periods prior to January 1, 2016 that are expected to be refunded or recovered through PJM wholesale transmission rates through December 2025. On May 31, 2018, FERC issued an order approving the settlement. Pursuant to the order, similar charges for the period January 1, 2016 through June 30, 2018 would also be refunded or recovered through PJM wholesale transmission rates over the subsequent 12-month period. PJM commenced billing the refunds and charges associated with this settlement in August 2018.

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DPL recorded a receivable to PJM for \$10 million and a related regulatory liability for \$10 million in 2018 and have been refunding or recovering these amounts through electric distribution customer rates.

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, 2019 and December 31, 2018:

Regulatory Assets (Account 182.3)	December 31, 2019	December 31, 2018
AMI programs - Deployment Costs	\$ 35	\$ 39
AMI programs - Legacy Meters	27	30
Electric Energy and Natural Gas Costs	10	7
Transmission formula rate annual reconciliations	2	14
Energy efficiency and demand response programs	75	73
Merger integration costs	8	11
Other	19	23
Total regulatory assets	\$ 176	\$ 197
Regulatory Liabilities (Account 254)	December 31, 2019	December 31, 2018
Deferred income taxes	\$ 477	\$ 510
Electric Energy and Natural Gas Costs	13	25
Other	18	33
Total regulatory liabilities	\$ 508	\$ 568

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	Deferred income taxes that are recoverable or refundable through customer rates, primarily associated with accelerated depreciation, the equity component of AFUDC, and the effects of income tax rate changes, including those resulting from the TCJA. These amounts include transmission-related regulatory liabilities that require FERC approval separate from the transmission formula rate. See Transmission-Related Income Tax Regulatory Assets section above for additional information.	Over the period in which the related deferred income taxes reverse, which is generally based on the expected life of the underlying assets. For TCJA, generally refunded over the remaining depreciable life of the underlying assets, except in certain jurisdictions where the commissions have approved a shorter refund period for certain assets not subject to IRS normalization rules.	No
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

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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.	2021	Maryland - No 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.	2034	Yes
Merger Integration Costs	Integration costs to achieve distribution synergies related to the PHI acquisition.	2023	Yes
Under (Over)-Recovered Revenue Decoupling	Electric and / or gas distribution costs recoverable from or (refundable) to customers under decoupling mechanisms.	2020	No

Capitalized Ratemaking Amounts Not Recognized

As of December 31, 2019 and 2018, 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 Statements of Operations and Comprehensive Income in the periods they are billable to customers.

3. 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
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:

Average Service Life Percentage by Asset Category	2019	2018
Electric - transmission and distribution	2.86 %	2.77 %
Gas - transportation and distribution	1.55 %	1.59 %
Common - electric and gas	6.24 %	3.70 %

The credits to AFUDC debt and equity were \$6 million and \$4 million for the years ended December 31, 2019 and 2018, respectively.

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DPL has material undivided interests in jointly owned electric transmission facilities, which are financed with its funds and 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, 2019 and 2018 were as follows:

Operator	PSEG/DPL
DPL's share at December 31, 2019	
	NJ/DE ^(a)
Plant in service	\$ 2
Accumulated depreciation	1
DPL's share at December 31, 2018	
	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.

4. 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, 2018 to December 31, 2019:

AROs at January 1, 2018	\$ 10
Net increase due to changes in, and timing of, estimated future cash flows	<u>1</u>
Non-nuclear AROs at December 31, 2018 (Account 230)	11
Net increase due to changes in, and timing of, estimated future cash flows	<u>1</u>
Non-nuclear AROs at December 31, 2019 (Account 230)	<u>\$ 12</u>

5. Income Taxes

Components of Income Tax Expense or Benefit

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

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	For the Year Ended December 31,	
	2019	2018
Included in operations:		
Federal		
Current	\$ 29	\$ (3)
Deferred	(21)	13
State		
Current	—	—
Deferred	14	12
Total (Accounts 409.1, 409.2, 410.1, 410.2, 411.1, 411.2, 411.4)	<u>\$ 22</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,	
	2019	2018
U.S. Federal statutory rate	21.0 %	21.0 %
Increase (decrease) due to:		
State income taxes, net of Federal income tax benefit	6.8	6.7
Amortization of investment tax credit, including deferred taxes on basis difference	(0.2)	(0.3)
Plant Basis differences	(0.4)	(0.3)
Excess deferred tax amortization	(14.2)	(12.0)
Other	—	0.4
Effective income tax rate	<u>13.0 %</u>	<u>15.5 %</u>

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, 2019 and 2018 are presented below:

	As of December 31,	
	2019	2018
Plant basis differences	\$ (753)	\$ (743)
Deferred pension and postretirement obligation	(42)	(46)
Deferred debt refinancing costs	(2)	(2)
Regulatory assets and liabilities	88	96
Tax loss carryforward	44	52

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Other, net	11	17
Deferred income tax liabilities, net (Accounts 190, 282, 283)	\$ (654)	\$ (626)
Unamortized investment tax credits (Account 255)	(2)	(2)
Total deferred income tax liabilities (net) and unamortized investment tax credits	<u>(656)</u>	<u>(628)</u>

The following table provides DPL's carryforwards, which are presented on a post-apportioned basis, as of December 31, 2019. Note, there were no Federal carryforwards.

State net operating losses	\$	654
Deferred taxes on state tax attributes (net)	\$	44
Year in which net operating loss carryforwards will begin to expire		2030

Tabular Reconciliation of Unrecognized Tax Benefits

The following tables presents changes in DPL's unrecognized tax benefits as of December 31, 2019 and 2018.

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		—
Unrecognized tax benefits at December 31, 2019	<u>\$</u>	<u>1</u>
Unrecognized tax benefits at January 1, 2018	\$	21
Change to positions that only affect timing		—
Increases based on tax positions prior to 2018		1
Decreases based on tax positions prior to 2018		(22)
Unrecognized tax benefits at December 31, 2018	<u>\$</u>	<u>—</u>

In 2018, DPL decreased its unrecognized state tax benefits due to the receipt of favorable guidance with respect to the deductibility of certain depreciable fixed assets. The recognition of the tax benefits related to DPL were offset by corresponding regulatory liabilities and that portion had no immediate impact to its effective tax rate.

Total amounts of interest and penalties recognized

DPL had no net interest and penalties receivable (payable), including interest and penalties related to tax positions reflected in its Balance Sheets at both December 31, 2019 and 2018.

DPL had no net interest and penalty expense, including interest and penalties related to tax positions, in its Statements of Income at both December 31, 2019 and 2018.

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

Taxpayer	Open Years
FERC FORM NO. 1 (ED. 12-88)	
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Exelon (and predecessors) and subsidiaries consolidated federal income tax returns	2002-2018
PHI Holdings and subsidiaries consolidated federal income tax returns	2016
Delaware separate corporate income tax returns	2002-2018
Maryland separate company corporate net income tax returns	2002-2018

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 exiting deferred income tax balances to reflect the changes in marginal rates, which results in either an increase or decrease to its nets 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. As a result of the rate changes, in 2018, DPL recorded a one-time decrease to deferred income taxes of approximately \$2 million and a corresponding regulatory liability of approximately \$2 million. In 2019, there were no material adjustments to income tax expense as a result of changes in state apportionment.

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 benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2019, DPL recorded a \$1 million allocation of federal tax benefits from Exelon under the Tax Sharing Agreement. During 2018, DPL did not record an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

6. Retirement Benefits

Exelon sponsored defined benefit pension plans and other postretirement benefit plans for essentially all current employees. The table below shows the pension and other postretirement benefit plans (OPEB) in which DPL employees participated at December 31, 2019.

Name of Plan:

Qualified Pension Plans:

- 1 Exelon Corporation Retirement Program^(a)
- 2 Pension Plan of Constellation Energy Group, Inc.^(b)
- 3 Pepco Holdings LLC Retirement Plan^(c)

Non-Qualified Pension Plans:

- 1 Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan^(c)
- 2 Conectiv Supplemental Executive Retirement Plan^(c)

Other Postretirement Benefit Plans:

- 3 PECO Energy Company Retiree Medical Plan^(a)

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4 Pepco Holdings LLC Welfare Plan for Retirees(c)

- (a) These plans are collectively referred to as the legacy Exelon plans.
- (b) These plans are collectively referred to as the legacy Constellation Energy Group (CEG) Plans.
- (c) 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 other postretirement benefit costs and contributions have been, and will continue to be, allocated to DPL based on both active and retired employee participation.

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 Property, plant and equipment within its Balance Sheets for the years ended December 31, 2019 and 2018.

	2019	2018
Pension and OPEB	\$ 15	\$ 6

Contributions

The following table provide DPL's contributions to the pension and OPEB plans for the years ended December 31, 2019 and 2018:

	2019	2018
Pension Benefits	\$ 1	\$ —
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 following table provides DPL's planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to other postretirement plans in 2020:

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
2020	\$ —	\$ 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 (IRC) and allow employees to contribute a portion of their pre-tax and after-tax

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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, 2019 and 2018.

	2019	2018
Savings Plan Matching Contributions	\$ 3	\$ 2

7. 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 normal purchases and normal sales (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.

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 referencing 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 Maryland Public Service Commission (MDPSC) and the Delaware Public Service Commission (DPSC). DPL's hedging programs are intended to reduce exposure to energy 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 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 price contracts through full requirements contracts.

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Gas Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability Exchange traded future contracts for 50% of estimated monthly purchase requirements each month, including purchases for storage injections.

As of December 31, 2019 and 2018, fair value balances associated with derivatives on DPL's Balance Sheet were immaterial.

Credit Risk

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

DPL has contracts to procure electric supply that provides 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, 2019, DPL's counterparty credit risk with suppliers was immaterial.

Credit-Risk-Related Contingent Features

DPL's electric supply procurement contracts do not contain provisions that would require them to post collateral.

DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral in the form of cash or credit support, which vary by contract and counterparty, with thresholds contingent upon DPL's credit rating. As of December 31, 2019, DPL was not required to post collateral for any of these agreements. If DPL lost its investment grade credit rating as of December 31, 2019, it could have been required to post incremental collateral to its counterparties of \$11 million.

8. 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 and bilateral credit agreements at December 31, 2019 and December 31, 2018:

Commercial Paper Issuer	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,	
	2019(a)(b)	2018(a)(b)	2019	2018	2019	2018
DPL	\$ 300	\$ 300	\$ 56	\$ —	2.02 %	2.07 %

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- (a) At December 31, 2019, excludes credit facility agreements arranged at minority and community banks with aggregate commitments of \$8 million. These facilities expire on October 9, 2020. These facilities are solely utilized to issue letters of credit. At December 31, 2018, excludes credit facility agreements arranged at minority and community banks with aggregate commitments of \$5 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 DPL 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 then available capacity under its credit facility.

At December 31, 2019, DPL had the following aggregate bank commitments, credit facility borrowings and available capacity under its credit facility:

Borrower	Facility Type	Aggregate Bank Commitment ^(a)	Facility Draws	Outstanding Letters of Credit	Available Capacity at December 31, 2019	
					Actual	To Support Additional Commercial Paper
DPL	Syndicated Revolver	\$ 300	\$ —	\$ —	\$ 300	\$ 244

- (a) Excludes additional credit facility agreements with aggregate commitments of \$8 million arranged with minority and community banks located primarily within DPL's service territories. These facilities expire on October 9, 2020. These facilities are solely utilized to issue letters of credit.

The following table presents the short-term borrowings activity for DPL during 2019 and 2018.

	2019		2018	
Average borrowings	\$	21	\$	87
Maximum borrowings outstanding	\$	125	\$	245
Average interest rates, computed on a daily basis		2.02 %		2.07 %
Average interest rates, computed at December 31		2.02 %		2.07 %

Revolving Credit Agreements

On May 26, 2016, PHI and DPL entered into an amendment to its Second Amended and Restated Credit Agreement dated as of August 1, 2011, which (i) extended the maturity date of the facility to May 26, 2021, (ii) removed PHI as a borrower under the facility, (iii) decreased the size of the facility from \$1.5 billion to \$900 million and (iv) aligned its financial covenant from debt to capitalization leverage ratio to interest coverage ratio. On May 26, 2018, DPL's syndicated revolving credit facilities had their maturity dates extended to May 26, 2023.

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 DPL's credit rating. The adder for the prime based borrowings is 7.5 basis points and for the LIBOR-based borrowings is 107.5 basis points. If DPL loses its investment grade rating, the maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points 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

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DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, 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, 2019 and December 31, 2018, \$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, 2019 and 2018:

	Rates	Maturity Date	December 31,	
			2019	2018
Long-term debt				
First mortgage bonds (Account 221)(a)	1.76% - 4.27%	2023 - 2049	\$ 1,445	\$ 1,370
Unsecured Tax-Exempt Bonds (Account 221)	1.63% - 5.40%	2024 - 2031	112	112
Medium-Terms Notes (unsecured) (Account 224)	7.61% - 7.72%	2027	10	22
Other (Accounts 227 and 243)	3.54%	2027	10	—
Total long-term debt			\$ 1,577	\$ 1,504
Unamortized debt discount and premium, net (Accounts 225 and 226)			1	2
Long-term debt			\$ 1,578	\$ 1,506

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

Long-term debt maturities at DPL in the periods 2020 through 2024 and thereafter are as follows:

Year	DPL
2020	\$ 80
2021	2
2022	2
2023	502
2024	1
Thereafter	990
Total	<u>\$ 1,577</u>

Debt Covenants

As of December 31, 2019, DPL is in compliance with debt covenants.

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9. Fair Value of Financial Assets and Liabilities

DPL measures and records 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:

- 1 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.
- 2 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.
- 3 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 the Carrying Amount

The following tables present the carrying amounts and fair values of DPL's short-term liabilities and long-term debt as of December 31, 2019 and 2018. 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, 2019				December 31, 2018			
	Carrying Amount	Fair Value			Carrying Amount	Fair Value		
		Level 2	Level 3	Total		Level 2	Level 3	Total
Long-term debt (Account 221, 224-227, 243)	\$ 1,579	\$ 1,408	\$ 311	\$ 1,719	\$ 1,506	\$ 1,303	\$ 193	\$ 1,496

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

Type	Level	Valuation
Long-term debt, including amounts due within one year		
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

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The following tables present assets and liabilities measured and recorded at fair value in DPL's Balance Sheet on a recurring basis and their level within the fair value hierarchy as of December 31, 2019 and 2018:

<u>As of December 31, 2019</u>	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents (Account 132-134, 136)(a)	\$ —	\$ —	\$ —	\$ —
Total assets	—	—	—	—
Liabilities				
Deferred compensation obligation (Account 228.3, 242)	—	—	—	—
Total liabilities	—	—	—	—
Total net assets (liabilities)	\$ —	\$ —	\$ —	\$ —

<u>As of December 31, 2018</u>	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents (Account 132-134,136)(a)	\$ 16	\$ —	\$ —	\$ 16
Total assets	16	—	—	16
Liabilities				
Deferred compensation obligation (Account 228.3, 242)	—	(1)	—	(1)
Total liabilities	—	(1)	—	(1)
Total net assets (liabilities)	\$ 16	\$ (1)	\$ —	\$ 15

(a) DPL excludes cash of \$13 million and \$8 million at December 31, 2019 and 2018, respectively.

DPL had immaterial Level 3 assets measured at fair value on a recurring basis during the years ended December 31, 2019 and 2018.

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, mutual funds, fixed income securities and life insurance policies. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The fair values of fixed income securities are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. 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. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets. 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

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investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to DPL. Therefore, DPL has not disclosed such inputs.

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

Mark-to-Market Derivatives. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that DPL believes provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The DPL's derivatives are predominantly at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. DPL considers credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

10. 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, 2019:

<u>Description</u>	<u>December 31, 2019</u>
Total Commitments	\$ 89

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Remaining commitments^(a) \$ 8

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

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 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, 2019, representing commitments potentially triggered by future events, were as follows:

	Expiration within						2025 and beyond
	Total	2020	2021	2022	2023	2024	
Surety bonds ^(a)	\$ 4	\$ 4	\$ —	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	11	1	1	2	1	3	3
Total commercial commitments	<u>\$ 15</u>	<u>\$ 5</u>	<u>\$ 1</u>	<u>\$ 2</u>	<u>\$ 1</u>	<u>\$ 3</u>	<u>\$ 3</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 zero at the end of the maximum lease term. The maximum 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 \$29 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, 2019 were as follows:

2020	\$ 11
2021	11
2022	10
2023	9
2024	9
Remaining years	<u>41</u>
Total minimum future lease payments	<u>\$ 91</u>

Environmental Remediation Matters

General

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

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.

As of both December 31, 2019 and 2018, 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 a reasonable possibility, 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.

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) 03/27/2020	Year/Period of Report 2019/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

11. Shareholder's Equity

The following table presents common stock authorized and outstanding as of December 31, 2019 and 2018:

	Par Value	Shares Authorized	December 31,	
			2019	2018
			Shares Outstanding	
DPL	\$ 2.25	1,000	1,000	1,000

12. Supplemental Financial Information

Supplemental Statement of Income Information

The following table provides additional information about DPL's Statements of Operations and Comprehensive Income for the years ended December 31, 2019 and 2018:

	For the Year Ended December 31,	
	2019	2018
Taxes other than income (Accounts 408.1 and 408.2)		
Utility(a)	\$ 18	\$ 21
Property	34	32
Payroll	4	3
Total taxes other than income	\$ 56	\$ 56

(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 the DPL's Consolidated Statements of Operations and Comprehensive Income.

Supplemental Statement of Cash Flows Information

Cash paid for interest (net of amount capitalized) was \$59 million and \$56 million for the years ended December 31, 2019 and 2018. Cash paid (refunded) for income taxes (net of refunds) was \$19 million and \$(6) million for the years ended December 31, 2019 and 2018, respectively.

DPL's Statement of Cash Flows included non-cash investing activities relating to capital expenditures not paid (decreased) increased by \$(4) million and \$22 million for the years ended December 31, 2019 and 2018, respectively.

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

13. Related Party Transactions

Expenses from Exelon Generation LLC

Exelon Generation Company LLC (Generation), a related party of DPL, provides a portion of DPL's energy requirements under its MDPSC and DPSC approved market based SOS and gas commodity programs. DPL's Purchased power from Generation was \$70 million and \$120 million for the years ended December 31, 2019 and 2018, respectively.

Operating and maintenance expense from Business Services Corporation

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

	Operating and maintenance from affiliates		Capitalized costs from affiliates	
	For the years ended December 31,		As of December 31,	
	2019	2018	2019	2018
BSC	\$ 52	\$ 51	\$ 25	\$ 28
PHISCO(a)	100	111	20	25

(a) Due to the PHI entities' system conversion to Exelon's accounting systems on January 1, 2018, corporate support services received from PHISCO are reported in Operating and maintenance from affiliates and in Capitalized costs beginning in 2018.

Current Payables (Account 234) to affiliates

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

	As of December 31,	
	2019	2018
Generation	\$ 7	\$ 7
Pepco	—	1
ACE	3	1
BSC	10	11
PHISCO	11	12
Exelon HoldCo.	1	1
Total	<u>\$ 32</u>	<u>\$ 33</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 PHI operate an intercompany money pool. DPL participates in the PHI intercompany money pool.

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				

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				120,170,527	120,170,527
5					
6					
7					
8					
9				147,396,994	147,396,994
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)	4,945,947,926	4,168,259,826
4	Property Under Capital Leases	11,214,816	11,214,816
5	Plant Purchased or Sold		
6	Completed Construction not Classified	357,338,773	285,123,079
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,314,501,515	4,464,597,721
9	Leased to Others		
10	Held for Future Use	7,083,458	7,083,458
11	Construction Work in Progress	125,378,143	93,107,626
12	Acquisition Adjustments	50,046,280	50,046,280
13	Total Utility Plant (8 thru 12)	5,497,009,396	4,614,835,085
14	Accum Prov for Depr, Amort, & Depl	1,477,597,220	1,140,535,163
15	Net Utility Plant (13 less 14)	4,019,412,176	3,474,299,922
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,392,270,288	1,081,252,275
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	39,915,551	13,871,507
22	Total In Service (18 thru 21)	1,432,185,839	1,095,123,782
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	45,411,381	45,411,381
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,477,597,220	1,140,535,163

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
627,781,255				149,906,845	3
					4
					5
62,120,832				10,094,862	6
					7
689,902,087				160,001,707	8
					9
					10
22,218,936				10,051,581	11
					12
712,121,023				170,053,288	13
242,198,913				94,863,144	14
469,922,110				75,190,144	15
					16
					17
240,836,322				70,181,691	18
					19
					20
1,362,591				24,681,453	21
242,198,913				94,863,144	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
242,198,913				94,863,144	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)		

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
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			22

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of 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	6,700,573	10,667,127
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	6,702,914	10,667,127
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	53,725,003	349,713
49	(352) Structures and Improvements	48,082,016	7,192,955
50	(353) Station Equipment	585,875,924	48,108,854
51	(354) Towers and Fixtures	73,977,809	
52	(355) Poles and Fixtures	518,183,971	15,807,687
53	(356) Overhead Conductors and Devices	299,036,553	17,741,680
54	(357) Underground Conduit	5,418,655	40,107,643
55	(358) Underground Conductors and Devices	19,767,480	3,623,536
56	(359) Roads and Trails	731,223	1
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,604,798,634	132,932,069
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	14,162,311	691,388
61	(361) Structures and Improvements	39,525,327	2,541,647
62	(362) Station Equipment	398,952,214	26,822,476
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	207,836,184	9,302,656
65	(365) Overhead Conductors and Devices	348,758,007	19,859,688
66	(366) Underground Conduit	23,481,562	237,234
67	(367) Underground Conductors and Devices	371,904,513	15,292,521
68	(368) Line Transformers	531,767,448	30,214,931
69	(369) Services	201,743,172	6,825,884
70	(370) Meters	128,305,609	3,522,989
71	(371) Installations on Customer Premises	42,257,103	520,893
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	65,305,793	5,061,816
74	(374) Asset Retirement Costs for Distribution Plant	5,041,445	933,216
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,379,040,688	121,827,339
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	31,314,495	119,057
88	(391) Office Furniture and Equipment	7,988,064	1,376,728
89	(392) Transportation Equipment	346,209	10,990,882
90	(393) Stores Equipment	504,667	
91	(394) Tools, Shop and Garage Equipment	16,432,820	1,410,847
92	(395) Laboratory Equipment	183,911	
93	(396) Power Operated Equipment		
94	(397) Communication Equipment	142,189,361	15,631,180
95	(398) Miscellaneous Equipment	2,952,388	22,336
96	SUBTOTAL (Enter Total of lines 86 thru 95)	204,596,146	29,551,030
97	(399) Other Tangible Property	4,735	
98	(399.1) Asset Retirement Costs for General Plant	138,909	-166,953
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	204,739,790	29,384,077
100	TOTAL (Accounts 101 and 106)	4,195,282,026	294,810,612
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)	4,195,282,026	294,810,612

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
		-69,067	17,298,633		4
		-69,067	17,300,974		5
					6
					7
					8
					9
					10
					11
					12
					13
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					46

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
			54,074,716	48
195,448		746,472	55,825,995	49
3,527,966			630,456,812	50
19,348			73,958,461	51
1,768,132			532,223,526	52
1,612,893			315,165,340	53
			45,526,298	54
195,779			23,195,237	55
			731,224	56
				57
7,319,566		746,472	1,731,157,609	58
				59
504		536,518	15,389,713	60
74,299		-43,027	41,949,648	61
2,590,864		158	423,183,984	62
				63
429,222		3,120,781	219,830,399	64
1,282,294		-3,120,939	364,214,462	65
			23,718,796	66
654,399			386,542,635	67
3,427,467			558,554,912	68
88,382			208,480,674	69
701,942			131,126,656	70
567,623			42,210,373	71
				72
2,081,345			68,286,264	73
37,652		-33,299	5,903,710	74
11,935,993		460,192	2,489,392,226	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			2,684,231	86
24,367			31,409,185	87
		-634,378	8,730,414	88
			11,337,091	89
			504,667	90
3,260,670			14,582,997	91
183,911				92
				93
3,301,673			154,518,868	94
			2,974,724	95
6,770,621		-634,378	226,742,177	96
			4,735	97
		28,044		98
6,770,621		-606,334	226,746,912	99
26,026,180		531,263	4,464,597,721	100
				101
				102
				103
26,026,180		531,263	4,464,597,721	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					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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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	Dec 2019	Dec 2021	3,177,062
3	Queenstown Substation: SSTA979	Dec 2019	May 2022	1,590,832
4	Ocean City-West Culver : SS322B	Nov 2019	Feb 2024	502,262
5	Lakeside Substation Land; 8 Acres, Talbot County MD	Dec 2010	Jun 2030	406,468
6	Magnolia Substation Land: 11+Acres	Nov 2010	Jun 2030	1,180,361
7				
8				
9				
10	Total of Land under \$250,000			226,473
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
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42				
43				
44				
45				
46				
47	Total			7,083,458

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	IDS Design Build Install DE	4,509,493
2	dMDCAP GSRI PT2 6708NSalisHebr	4,121,070
3	EMS Implementation Project Software	3,817,975
4	23070 Cool Spring - Indian Ri	3,379,362
5	Substation FO Entrance DPL MD	2,781,014
6	Indian River Spare Transformer	2,492,751
7	Crisfield Substation - New 69KV Term	2,424,906
8	Crisfield Kings Creek Construction	1,837,018
9	6719 E Market To Cambridge Rebuild	1,701,769
10	SS319B Replace Clayton T1 ECA	1,672,415
11	Substation FO Entrance DE	1,658,710
12	DPL MD CAP GSRI PT 2 Distribution	1,594,034
13	DPL MD CAP: CHESTERTOWN: Distribution	1,575,467
14	Ocean City Sub Upgrade Worcest	1,546,509
15	Router Upgrade Cores- Edges DE	1,546,451
16	3G AP Replacement DPL DE	1,414,259
17	EMS Implementation Project Software	1,392,944
18	BIDA-AMI Ph2 Software	1,384,773
19	Bay Region Mobile XFMR	1,364,772
20	13812 Hares Corner - Red Lion	1,331,729
21	UG Primary Repl Caine Woods OC	1,262,314
22	N. Salisbury Spare Transformer	1,183,250
23	Misc Planned Transm DE	1,119,656
24	Crisfield T1 Replace XFMR ECA	1,116,958
25	3G AP Replacement DPL MD	1,095,180
26	Tower Replacement DE	1,092,481
27	East New Market T2 Install	1,073,433
28	Maryland Sub Spare Transformer	1,062,512
29	138th Street Dist Automation	1,058,751
30	Miscellaneous Projects Under \$1,000,000	39,495,670
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	93,107,626

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	1,002,152,552	1,002,152,552		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	122,808,588	122,808,588		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,125,505	2,125,505		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	58,365	58,365		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	124,992,458	124,992,458		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	26,026,182	26,026,182		
13	Cost of Removal	22,086,907	22,086,907		
14	Salvage (Credit)	234,421	234,421		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	47,878,668	47,878,668		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17		1,985,933	1,985,933		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,081,252,275	1,081,252,275		

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	392,383,042	392,383,042		
26	Distribution	626,026,711	626,026,711		
27	Regional Transmission and Market Operation				
28	General	62,842,522	62,842,522		
29	TOTAL (Enter Total of lines 20 thru 28)	1,081,252,275	1,081,252,275		

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) 03/27/2020	Year/Period of Report 2019/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	\$ 58,365
Total	\$ 58,365

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				
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14				
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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
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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	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)	3,799,260	442,943	Electric
9	Distribution Plant (Estimated)	33,691,357	4,475,602	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)	37,490,617	44,642,941	
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)	37,490,617	44,642,941	

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

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

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

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		2020	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	228,037.00	8,103,320		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	DE RPS RECs Purchased	867,129.00	19,176,887		
10					
11	MD HPS RECs Purchased	2,000.00	1,200		
12	MD RECs Received	421,680.00	2,743,040		
13					
14					
15	Total	1,290,809.00	21,921,127		
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20	Total				
21	Cost of Sales/Transfers:				
22	DE RECs Retired	768,226.00	18,493,114		
23	MD RECs Retired	423,680.00	2,744,240		
24					
25					
26					
27					
28	Total	1,191,906.00	21,237,354		
29	Balance-End of Year	326,940.00	8,787,093		
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/transfersors 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.

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
						228,037.00	8,103,320	1
								2
								3
								4
								5
								6
								7
								8
						867,129.00	19,176,887	9
								10
						2,000.00	1,200	11
						421,680.00	2,743,040	12
								13
								14
						1,290,809.00	21,921,127	15
								16
								17
								18
								19
								20
								21
						768,226.00	18,493,114	22
						423,680.00	2,744,240	23
								24
								25
								26
								27
						1,191,906.00	21,237,354	28
						326,940.00	8,787,093	29
								30
								31
								32
								33
								34
								35
								36
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								46

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

Schedule Page: 228 Line No.: 9 Column: b
Represents renewable energy credits acquired and received to meet the Renewable Energy Portfolio Standards (RPS) for the state of DE.

Schedule Page: 228 Line No.: 9 Column: c
Represents the dollar value of renewable energy credits acquired to meet the Renewable Energy Portfolio Standards (RPS) for the state of DE.

Schedule Page: 228 Line No.: 11 Column: b
Represents renewable energy credits acquired and received to meet the Renewable Energy Portfolio Standards (RPS) for the state of MD.

Schedule Page: 228 Line No.: 11 Column: c
Represents the dollar value of renewable energy credits acquired to meet the Renewable Energy Portfolio Standards (RPS) for the state of MD.

Schedule Page: 228 Line No.: 12 Column: b
Represents renewable energy credits transferred to DPL under the Renewable Energy Portfolio Standards (RPS) for the state of MD.

Schedule Page: 228 Line No.: 12 Column: c
Represents the dollar value of renewable energy credits transferred under the Renewable Energy Portfolio Standards (RPS) for the state of MD.

Schedule Page: 228 Line No.: 28 Column: b
Represents renewable energy credits retired under the Renewable Energy Portfolio Standards (RPS) for the states of DE and MD.

Schedule Page: 228 Line No.: 28 Column: c
Represents the dollar value of renewable energy credits retired under the Renewable Energy Portfolio Standards (RPS) for the states 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		2020	
		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/transfersors 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.

2021		2022		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
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								46

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					

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					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22					
23					
24					
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26					
27					
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29					
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31					
32					
33					
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35					
36					
37					
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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	Wilmington Coal Gas-Site Clean Up	144,364		407.3	144,364	
2	Deferred Fuel Costs		11,419,081	various	9,370,225	2,048,856
3	Other Vacation Accrual	7,543,937	7,203,498	various	7,543,940	7,203,495
4	Asset Retirement Obligation	1,030,723	465,879	403.1	111,761	1,384,841
5	Transmission Service Revenue	13,637,201	6,119,097	various	17,603,508	2,152,790
6	DE Integrated Resource Planning (IRP)	463,375		407.3	358,740	104,635
7	DE Bluewater Wind Request for Proposal Costs	562,571		407.3	435,537	127,034
8	DE Electric Costs to Achieve (CTA) Deferral	5,486,074		407.3	1,473,485	4,012,589
9	FAS 133 DE Gas Derivatives	29,115	1,417,934	807.5	29,116	1,417,933
10	DE Third Party Supplier Recovery	1,404	647,338	various	404,361	244,381
11	MD Third Party Supplier Recovery	2,083,159	670,571	various	1,156,339	1,597,391
12	MD Costs to Achieve (CTA) Deferral	3,890,043		407.3	1,044,736	2,845,307
13	Billing System-MD Recovery	1,005,140		903	321,644	683,496
14	MD Rate Case Costs	119,826		928	89,648	30,178
15	DE DSM - Energy Efficiency	45,152	280,652	421	10,429	315,375
16	AMI / Smart Grid - DE	36,773,205	103,764	various	4,010,597	32,866,372
17	Recoverable DE DLC Costs	17,755,529		407.3	2,102,473	15,653,056
18	DE Gas IMU	7,360,231	21,208	various	706,772	6,674,667
19	DE Gas Costs to Achieve (CTA) Deferral	1,694,653		407.3	413,392	1,281,261
20	DE Gas IMU Battery Project Costs	3,452,713		426.5	1,726,356	1,726,357
21	DSM - Energy Efficiency Products MD	46,288,484	28,109,594	407.3	23,953,601	50,444,477
22	DSM - Direct Load Control Program MD	8,461,492	1,048,609	407.3	1,707,428	7,802,673
23	AMI / Smart Grid - MD	13,744,115	72,792	407.3	1,773,173	12,043,734
24	MD AMI Loss on Retirement of Meters	11,780,190		407.3	1,365,429	10,414,761
25	Delaware SOS:					
26	DE SOS - Transmission	4,192,948	4,613,625	407.3	4,291,699	4,514,874
27	Maryland SOS:					
28	MD SOS - Transmission	2,544,581	3,547,056	407.3	3,135,873	2,955,764
29	MD SOS - Administrative Costs	382,225	385,742	407.3	434,250	333,717
30	MD Incremental Storm Costs	4,312,041		various	934,440	3,377,601
31	Tax Cuts and Jobs Act	1,761,387				1,761,387
32	MD RM54 Recovery	108,376	53,204			161,580
33	DE Electric Distribution System Improvement Charge		45,674	254	45,674	
34	DE Gas Distribution System Improvement Charge		3,589	254	3,589	
35	MD Electric Vehicle		141,896			141,896
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43						
44	TOTAL	196,654,254	66,370,803		86,702,579	176,322,478

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

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

The following are the individual components of "Various"-

\$	1,262,216	recorded to account 254 - Reclass consistent with regulatory recovery position
	450	recorded to account 480
	1,389	recorded to account 481
	2,345	recorded to account 489
	<u>8,103,825</u>	recorded to account 805.1
\$	9,370,225	Total

Schedule Page: 232 Line No.: 3 Column: d

The following are the individual components of "Various"-

\$	380,375	recorded to account 236 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability.
	5,825,044	recorded to account 242 - Regulatory asset recovery results from reduction of company vacation liability and associated payroll tax liability.
	<u>1,338,521</u>	recorded to account 923
\$	7,543,940	Total

Schedule Page: 232 Line No.: 5 Column: d

The following are the individual components of "Various":

\$	2,946,017	recorded to account 254 - recovery of Tax Cuts and Jobs Act regulatory liability from Page 278, Line 17
	<u>14,657,491</u>	recorded to account 456.1
\$	17,603,508	Total

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

The following are the individual components of "Various"-

\$	167,388	recorded to account 144 - Relief of Regulatory Asset through Accounts Receivable Reserve adjustments
	<u>236,973</u>	recorded to account 232 - Relief of Regulatory Asset through Third Party Supplier Discount
\$	404,361	Total

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

The following are the individual components of "Various"-

\$	546,130	recorded to account 144 - Relief of Regulatory Asset through Accounts Receivable Reserve adjustments
	<u>610,209</u>	recorded to account 232 - Relief of Regulatory Asset through Third Party Supplier Discount
\$	1,156,339	Total

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

The following are the individual components of "Various"-

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

Schedule Page: 232 Line No.: 18 Column: d

The following are the individual components of "Various"-

\$	636,270	recorded to account 407.3
	<u>70,502</u>	recorded to account 923
\$	706,772	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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 30 Column: d

The following are the individual components of "Various"-

\$	118,984	recorded to account 407.3
	11,436	recorded to account 408.1
	61,704	recorded to account 588
	692,187	recorded to account 593
	46,260	recorded to account 903
	<u>3,869</u>	recorded to account 908
\$	934,440	Total

Schedule Page: 232 Line No.: 33 Column: d

The following are the individual components of "254":

\$	45,674	recorded to account 254 - Reclass consistent with regulatory recovery position
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Schedule Page: 232 Line No.: 34 Column: d

The following are the individual components of "254":

\$	3,589	recorded to account 254 - Reclass consistent with regulatory recovery position
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MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Prepaid Pension Costs	185,579,847	670,527	various	15,406,008	170,844,366
2	LT Customer Payment Receivables	121,889		143.0	30,487	91,402
3	LT Receivable from PJM	2,425,753	16,461	143.0	324,538	2,117,676
4	Other A/R Worker Compensation	407,775	865,934	various	521,361	752,348
5	Other	8,314	13,530	various	1,891	19,953
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	188,543,578				173,825,745

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

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

Prepaid pension is offset in accounts 926, 107 and 108.

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

Worker's Compensation is offset in Accounts 925, 107 and 108.

Schedule Page: 233 Line No.: 5 Column: d

Other is offset primarily in Account 131 and 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	69,421,057	56,701,567
3	Electric FAS109	128,741,286	120,182,946
4			
5			
6			
7	Other	557,534	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	198,719,877	176,884,513
9	Gas		
10	Gas	10,946,229	8,499,429
11	Gas FAS109	13,468,552	12,709,980
12			
13			
14			
15	Other	90,761	
16	TOTAL Gas (Enter Total of lines 10 thru 15)	24,505,542	21,209,409
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	223,225,419	198,093,922

Notes

Account 190 Fed Inc. Activity:

410.1 Debits 18,791,672
 411.1 Credits 6,008,998
 Net Debits 12,782,674

Account 190 State Inc. Activity:

410.2 Debits 49,926
 411.2 Credits 2,493,219
 Net Debits (2,443,293)

Account 190 Activity B/S Only:

410 Debits -
 411 Credits 12,243,599
 Net Debits 12,243,599

Net Change (22,582,980)

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

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

190	Electric	Gas	Total
Allowance for Doubtful Accounts	\$ 3,027,509	\$ 492,850	\$ 3,520,359
Charitable Contributions	557,534	90,761	648,295
Claims Reserve	479,514	78,060	557,574
Deferred ITC	560,263	91,206	651,469
Environmental Expense	290,911	47,358	338,269
Interest on Contingent Taxes	-	-	-
Merrill Creek	236,609	-	236,609
OPEB	4,366,702	710,859	5,077,561
Other (190)	5,444,769	886,358	6,331,127
Other Labor Related Accruals	5,141,753	837,030	5,978,783
Reg Asset - DSM	25,710	-	25,710
Reg Liab - FERC Formula Adj.	-	-	-
Reg Liab - Other	6,172,081	1,448,156	7,620,237
Renewable Energy Credits	554,953	455,942	1,010,895
FAS 109 Deferred Taxes - 190	214,812	34,969	249,781
FAS 109 Deferred Taxes - Property Gross Up	110,068,691	12,229,855	122,298,546
FAS 109 Deferred Taxes - Tax Cuts and Jobs Act Gross Up	16,676,563	2,113,082	18,789,645
Federal and State NOL	44,901,503	4,989,056	49,890,559
Total	\$ 198,719,877	\$ 24,505,542	\$ 223,225,419

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

190	Electric	Gas	Total
Allowance for Doubtful Accounts	\$ 3,486,262	\$ 567,531	\$ 4,053,793
Charitable Contributions	-	-	-
Claims Reserve	239,094	38,922	278,016
Deferred ITC	477,683	77,762	555,445
Environmental Expense	226,244	36,830	263,074
Interest on Contingent Taxes	(10,609)	(1,179)	(11,788)
Merrill Creek	-	-	-
OPEB	3,939,306	641,282	4,580,588
Other (190)	3,861,530	628,513	4,490,043
Other Labor Related Accruals	4,642,830	755,809	5,398,639
Reg Asset - DSM	60,490	-	60,490
Reg Liab - FERC Formula Adj.	-	-	-
Reg Liab - Other	1,096,753	178,541	1,275,294
Renewable Energy Credits	559,383	487,513	1,046,896
FAS 109 Deferred Taxes - 190	183,150	29,815	212,965
FAS 109 Deferred Taxes - Property Gross Up	104,811,844	11,645,760	116,457,604
FAS 109 Deferred Taxes - Tax Cuts and Jobs Act Gross Up	13,576,414	1,707,406	15,283,820
Federal and State NOL	39,734,139	4,414,904	44,149,043
Total	\$ 176,884,513	\$ 21,209,409	\$ 198,093,922

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	1,000		
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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
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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	735,291,727
14	Subtotal	447,217,046
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40	TOTAL	448,555,442

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		
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22	TOTAL	9,924,450

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	641,300
19			
20	SUBTOTAL - Account 221	1,557,230,000	19,638,613
21			
22			
23	Account 224 - Other LTD		
24	Medium Term Notes 7.61% Series C	12,000,000	6,209
25			189,913 D
26	Medium Term Notes 7.72% Series C	10,000,000	
27			
28	SUBTOTAL - Account 224	22,000,000	196,122
29			
30			
31			
32			
33	TOTAL	1,579,230,000	19,834,735

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	254,727	2
10/10/1994	10/01/2029	10/10/1994	10/01/2029	30,000,000	432,896	3
07/01/1999	07/01/2024	07/01/1999	07/01/2024	22,330,000	350,854	4
07/01/1999	07/01/2024	07/01/1999	07/01/2024	11,000,000	177,469	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	4,233,600	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	163,875	18
						19
				1,557,230,000	57,215,921	20
						21
						22
						23
02/12/1997	12/02/2019	02/12/1997	12/02/2019		839,637	24
						25
02/07/1997	02/01/2027	02/07/1997	02/01/2027	10,000,000	772,000	26
0	0	0	0			27
0	0	0	0	10,000,000	1,611,637	28
0	0	0	0			29
0	0	0	0			30
0	0	0	0			31
						32
				1,567,230,000	58,827,558	33

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 18 Column: d

\$75 million of First Mortgage Bonds were issued on December 12, 2019.

Schedule Page: 256 Line No.: 24 Column: e

\$12 million of secured medium term notes matured on December 2, 2019

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 \$175,224, 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)	147,396,994
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		22,292,192
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	-69,290,257
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	100,398,929
28	Show Computation of Tax:	
29	Federal Income Tax at 21%	21,083,775
30	Net Operating Loss Utilized	
31	2018 Return to Accrual	7,756,374
32	Income Tax Credits	43,375
33		
34	TOTAL (lines 29 through 32)	28,796,774
35		
36	Federal Income Tax Acct 409.10	29,384,121
37	Federal Income Tax Acct 409.20	587,347
38	Total	28,796,774
39		
40		
41		
42		
43		
44		

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) 03/27/2020	2019/Q4
FOOTNOTE DATA			

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

Net Income for the Year (Page 117)	147,396,994
Federal Income Taxes	7,764,799
State Income Taxes	14,527,393
Pre-tax Book Income	169,689,186
Increase (Decrease) in Taxable Income Resulting From:	
Removal Costs	(24,279,170)
Mixed Service Costs	(8,088,511)
Repair Allowance - Unit of Property	(53,619,831)
Bonus Depreciation	-
Depreciation	5,869,637
CIAC	9,550,405
AFUDC Equity	(3,978,538)
AFUDC Debt	(1,961,867)
Capitalized Interest	3,392,013
Gain/Loss on Disposition of Property	472,076
Other (Property)	2,379,658
Regulatory Assets & Liabilities	6,243,174
Pension/OPEB/SERP	7,426,038
Accrued Liabilities	(10,672,352)
Merger Commitment Deferrals	(2,664,530)
State Income Taxes Deductible	-
Other (Net)	641,541
Total Schedule M's	(69,290,257)
Federal Taxable Income	100,398,929
Computation of Federal Income Tax:	
Federal Income Tax on Current Year Income (21%)	21,083,775
Net Operating Loss Utilized	-
2018 Return to Accrual	7,756,374
Income Tax Credits	(43,375)
Federal Income Tax	28,796,774
Federal Income Tax Account 409.10	29,384,121
Federal Income Tax Account 409.20	(587,347)
Total	28,796,774

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			28,796,775	18,629,445	-892,892
2	State Income Tax			6,940	-63,898	-70,838
3	Maryland Use Tax	777,430		-6,000	-164,455	-119,174
4	Maryland Property Taxes		7,716,763	15,030,285	15,935,998	710,127
5	Maryland Prop. Taxes Other					557,423
6	Other Maryland Taxes	29,634		8,195,757	8,173,690	-170,936
7	Delaware Property Taxes		9,139,426	18,281,476	19,763,089	805,956
8	Local Delaware Taxes	907,945		1,014,456	866,503	
9	Other Delaware Taxes	1,006,047		9,147,881	9,103,923	
10	Virginia Use Tax		1,066	1,067	-2,803	
11	Virginia Property Taxes			190,702	95,972	932
12	West Virginia Property Taxes			4,517	4,517	
13	Mississippi Property Taxes	6,774		3,569	5,095	
14	New Jersey Property Taxes			642,698	642,698	
15	Pennsylvania Franchise					
16	Federal Excise Tax			26,714	26,714	
17	Payroll Taxes	1,248,190		4,217,006	4,215,826	
18						
19						
20						
21						
22						
23						
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40						
41	TOTAL	3,976,020	16,857,255	85,553,843	77,232,314	820,598

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then 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 (i) 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)	
9,274,438		25,933,274			2,863,500	1
		6,246			694	2
816,712		-6,000				3
	7,912,349	15,030,285				4
557,423						5
	119,234	8,195,757				6
	9,815,084	11,568,966			6,712,510	7
1,055,898		1,014,456				8
1,050,005		6,948,107			2,199,775	9
2,804		1,067				10
95,661		190,702				11
					4,517	12
5,248					3,569	13
					642,698	14
						15
		35,460			-8,746	16
1,249,371		3,583,014			633,992	17
						18
						19
						20
						21
						22
						23
						24
						25
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						32
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						40
14,107,560	17,846,667	72,501,334			13,052,509	41

Name of Respondent
 Delmarva Power & Light Company

This Report Is:
 (1) An Original
 (2) A Resubmission

Date of Report
 (Mo, Da, Yr)
 03/27/2020

Year/Period of Report
 End of 2019/Q4

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%	11,870			411.4	1,710	
4	7%	582,267			411.4	83,889	
5	10%	1,526,093			411.4	219,867	
6							
7							
8	TOTAL	2,120,230				305,466	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	10% Gas Utility	230,370				41,002	
11	Total Other	230,370	0		0	41,002	
12	Account 255	2,350,600				346,468	
13							
14							
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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
10,160			3
498,378			4
1,306,226			5
			6
			7
1,814,764			8
			9
189,368			10
189,368			11
2,004,132			12
			13
			14
			15
			16
			17
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			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	2,301,450	143	983,640	1,894,497	3,212,307
2	DE Charitable Contributions	5,833,822	426.1	1,060,869		4,772,953
3	MD Charitable Contributions	1,131,154	426.1	163,996		967,158
4	MFN Credits	4,053,618	427.0	2,664,579		1,389,039
5	Supplier Deposits	670,293	131.0	51,586	114,027	732,734
6	Merrill Creek Lease	7,347,418	418.0	541,147	4,128,991	10,935,262
7	Other				831,278	831,278
8						
9						
10						
11						
12						
13						
14						
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44						
45						
46						
47	TOTAL	21,337,755		5,465,817	6,968,793	22,840,731

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

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
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							9
							10
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							12
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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 rating 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	953,519,464	31,327,795	35,061,606
3	Gas	105,946,607	3,481,548	3,895,734
4	Non Operations			
5	TOTAL (Enter Total of lines 2 thru 4)	1,059,466,071	34,809,343	38,957,340
6	FASB 109	-318,973,492		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	740,492,579	34,809,343	38,957,340
10	Classification of TOTAL			
11	Federal Income Tax	546,267,265	20,412,583	31,359,996
12	State Income Tax	194,225,314	14,396,760	7,597,344
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
730				Various	2,313,331	952,099,714	2
81					256,355	105,788,857	3
							4
811					2,569,686	1,057,888,571	5
				254	15,233,872	-303,739,620	6
							7
							8
811					17,803,558	754,148,951	9
							10
633				254	17,026,026	552,346,511	11
178				254	777,532	201,802,440	12
							13

NOTES (Continued)

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

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

282	Electric	Gas	Total
Plant Related - APB 11 Deferred Taxes	972,397,755	108,044,195	1,080,441,950
Plant Related - FAS 109 Deferred Taxes	(292,855,500)	(32,539,500)	(325,395,000)
CIAC - Non Rate Base	(26,643,462)	(2,960,385)	(29,603,847)
Leased Vehicles - Non Rate Base	7,765,171	862,797	8,627,968
FAS 109 AFUDC Equity Deferred Taxes	5,779,357	642,151	6,421,508
FAS 109 1/1/2005 Deferred Tax Balance	-	-	-
Reg Liability - Other	-	-	-
Subtotal - p275	666,443,321	74,049,258	740,492,579
FASB 109	287,076,143	31,897,349	318,973,492
Adjusted Total	953,519,464	105,946,607	1,059,466,071

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

282	Electric	Gas	Total
Plant Related - APB 11 Deferred Taxes	971,810,109	107,978,901	1,079,789,010
Plant Related - FAS 109 Deferred Taxes	(279,843,659)	31,093,740)	(310,937,399)
CIAC - Non Rate Base	(27,475,566)	(3,052,841)	(30,528,407)
Leased Vehicles - Non Rate Base	7,765,171	862,797	8,627,968
FAS 109 AFUDC Equity Deferred Taxes	6,478,001	719,778	7,197,779
FAS 109 1/1/2005 Deferred Tax Balance	-	-	-
Reg Liability - Other	-	-	-
Subtotal - p275	678,734,056	75,414,895	754,148,951
FASB 109	273,365,658	30,373,962	303,739,620
Adjusted Total	952,099,714	105,788,857	1,057,888,571

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	142,588,351	6,699,244	20,628,706
4	Electric Non Operations	-3,207,962		
5	Other			
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	139,380,389	6,699,244	20,628,706
10	Gas			
11	Gas Operations	18,293,237	1,090,573	2,845,787
12	Gas Non Operations	-522,226		
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	17,771,011	1,090,573	2,845,787
18	FAS 109	-48,785,898		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	108,365,502	7,789,817	23,474,493
20	Classification of TOTAL			
21	Federal Income Tax	75,130,547	5,400,738	19,129,245
22	State Income Tax	33,234,955	2,389,079	4,345,248
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	5,706,347			122,952,542	3
2,861,586		Various	1,647,765			-1,994,141	4
							5
							6
							7
							8
2,861,586			7,354,112			120,958,401	9
							10
		Various	235,832			16,302,191	11
465,840		Various	268,240			-324,626	12
							13
							14
							15
							16
465,840			504,072			15,977,565	17
				254	9,306,427	-39,479,471	18
3,327,426			7,858,184		9,306,427	97,456,495	19
							20
2,306,927		Various	5,448,136	Various	9,306,427	67,567,258	21
1,020,499		Various	2,410,048			29,889,237	22
							23

NOTES (Continued)

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

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

283	Electric	Gas	Total
Blueprint for the Future	-	-	-
Deferred Fuel	-	-	-
Deferred Fuel Interest	-	-	-
Interest on Contingent Taxes	-	-	-
Materials Reserve	(112,593)	(18,329)	(130,922)
Merger Commitment Fees	(3,207,962)	(522,226)	(3,730,188)
Pension	44,256,129	7,204,486	51,460,615
Property Taxes	4,017,656	654,037	4,671,693
Reacquired Debt	1,550,741	252,446	1,803,187
Reg Asset - DSM	14,011,050	-	14,011,050
Reg Asset - FERC Formula Rate Adj.	3,779,550	-	3,779,550
Reg Asset - Other	32,018,681	3,688,793	35,707,474
Reg Asset- COPCO Acquisition Adjustment	793,043	-	793,043
Reg Liab - Other	-	-	-
Subtotal p276	97,106,295	11,259,207	108,365,502
FASB 109 Above if not separately removed	42,274,094	6,511,804	48,785,898
Total	139,380,389	17,771,011	157,151,400

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

283	Electric	Gas	Total
Blueprint for the Future	-	-	-
Deferred Fuel	-	-	-
Deferred Fuel Interest	-	-	-
Interest on Contingent Taxes	-	-	-
Materials Reserve	(196,709)	(32,022)	(228,731)
Merger Commitment Fees	(1,994,141)	(324,626)	(2,318,767)
Pension	38,047,032	6,193,703	44,240,735
Property Taxes	4,068,403	662,298	4,730,701
Reacquired Debt	1,302,418	212,021	1,514,439
Reg Asset - DSM	14,462,220	-	14,462,220
Reg Asset - FERC Formula Rate Adj.	596,646	-	596,646
Reg Asset - Other	30,397,001	4,062,251	34,459,252
Reg Asset- COPCO Acquisition Adjustment	-	-	-
Reg Liab - Other	-	-	-
Subtotal p277	86,682,870	10,773,625	97,456,495
FAS109	34,275,531	5,203,940	39,479,471
Total	120,958,401	15,977,565	136,935,966

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	458,092,186	various	29,868,768		428,223,418
3	SFAS Gas	51,877,705	various	3,545,442		48,332,263
4	Maryland SOS:					
5	MD Energy	3,391,578	407.3	6,761,717	3,983,462	613,323
6	Delaware SOS:					
7	DE Energy	6,872,649	407.3	19,246,910	18,437,895	6,063,634
8	DE Administrative Costs	3,246,771	407.3	1,243,464	1,870,164	3,873,471
9	DE SOS Interest	285,358	various	535,592	662,821	412,587
10	DE Qualified Fuel Cell Facility	7,793,712	407.3	35,034,608	33,841,807	6,600,911
11	DE Renewable Portfolio Surcharge Deferral	3,212,058	407.3	6,001,214	3,987,766	1,198,610
12	DE Deferred Fuel Costs-Gas	3,845,769	various	11,900,163	8,054,394	
13	DE Distribution Rate Reserve	1,638,056	various	1,655,369	17,313	
14	DE Gas Rate Reserve	4,439,719	various	5,100,304	660,585	
15	MD Grid Resiliency Charge	285,846	various	324,445	42,901	4,302
16	MD Dynamic Pricing - Critical Peak Rebate Credits	92,767	407.3	882,637	1,008,128	218,258
17	Tax Cuts and Jobs Act	5,971,649	various	4,496,012	1,801,955	3,277,592
18	DSM Direct Load Control Program-MD	724,549	407.3	1,645,585	1,480,963	559,927
19	DSM-Energy Efficiency Products-MD	4,248,468	407.3	4,204,518	1,016,331	1,060,281
20	MD RM54 Recovery	28,907	903.0	9,772		19,135
21	MD Bill Stabilization Adjustment Deferral	4,136,097	456.0	7,265,537	7,007,035	3,877,595
22	SOS Deferral for FERC 494 Settlement	7,238,118	407.3	5,081,325	383,450	2,540,243
23	DE PSC Refund	650,391	various	650,391		
24	DE Electric Distribution System Improvement Chrg		182.3	45,674	348,468	302,794
25	DE Gas Distribution System Improvement Charge		182.3	3,589	422,003	418,414
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	568,072,353		145,503,036	85,027,441	507,596,758

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

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

The following are the individual components of "various":

\$	8,545,902	recorded to account 190.0; Reversal of SFAS 109 regulatory liability deferred taxes
	13,710,484	recorded to account 282.0; Reversal of SFAS 109 regulatory liability deferred taxes
	7,998,563	recorded to account 283.0; Reversal of SFAS 109 regulatory liability deferred taxes
	<u>(386,181)</u>	recorded to account 923.0
\$	29,868,768	

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

The following are the individual components of "various":

\$	757,190	recorded to account 190.0; Reversal of SFAS 109 regulatory liability deferred taxes
	1,523,387	recorded to account 282.0; Reversal of SFAS 109 regulatory liability deferred taxes
	1,307,774	recorded to account 283.0; Reversal of SFAS 109 regulatory liability deferred taxes
	<u>(42,909)</u>	recorded to account 923.0
\$	3,545,442	

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

The following are the individual components of "various":

\$	3,088	recorded to account 419
	<u>532,504</u>	recorded to account 431
\$	535,592	

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

The following are the individual components of "various":

\$	1,043,668	recorded to account 182.3 - Reclass consistent with regulatory recovery position; included in Deferred Fuel Costs from line 2, pg. 232
	36,344	recorded to account 431
	<u>10,820,151</u>	recorded to account 805.1
\$	11,900,163	

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

The following are the individual components of "various":

\$	81,225	recorded to account 431
	1,298,848	recorded to account 440
	160,659	recorded to account 442
	<u>114,637</u>	recorded to account 444
\$	1,655,369	

Schedule Page: 278 Line No.: 14 Column: c

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

The following are the individual components of "various":

\$	152,919	recorded to account 431
	3,329,733	recorded to account 480
	875,361	recorded to account 481
	<u>742,291</u>	recorded to account 489
\$	5,100,304	

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

The following are the individual components of "various":

\$	302	recorded to account 142 - billing adjustments to previously billed amounts
	<u>324,143</u>	recorded to account 254 - moved to line 30 - MD Bill Stabilization Adjustment Deferral to be refunded to customers
\$	324,445	

Schedule Page: 278 Line No.: 17 Column: c

The following are the individual components of "various":

\$	2,946,017	recorded to account 182.3 - reclass of Tax Cuts and Jobs Act amounts included in Transmission Service Revenue from line 5, pg. 232
	2,603	recorded to account 456
	<u>1,547,392</u>	recorded to account 456.1
\$	4,496,012	

Schedule Page: 278 Line No.: 23 Column: c

The following are the individual components of "various":

\$	218,548	recorded to account 182.3 - Reclass consistent with regulatory recovery position; included in Deferred Fuel Costs from line 2, pg. 232
	<u>431,843</u>	recorded to account 254 - moved to line 14 - DE Renewable Portfolio Surcharge Deferral to be recovered through RPS rates
\$	650,391	

Schedule Page: 278 Line No.: 24 Column: c

The following are the individual components of "182.3":

\$	45,674	recorded to account 182.3 - Reclass consistent with regulatory recovery position
----	--------	--

Schedule Page: 278 Line No.: 25 Column: c

The following are the individual components of "various":

\$	3,589	recorded to account 182.3 - Reclass consistent with regulatory recovery position
----	-------	--

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	645,138,178	669,075,153
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	266,583,434	263,426,317
5	Large (or Ind.) (See Instr. 4)	18,093,752	22,263,583
6	(444) Public Street and Highway Lighting	13,852,714	13,826,714
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	943,668,078	968,591,767
11	(447) Sales for Resale	7,782,550	12,583,500
12	TOTAL Sales of Electricity	951,450,628	981,175,267
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	951,450,628	981,175,267
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,682,931	2,863,959
17	(451) Miscellaneous Service Revenues	565,550	752,442
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	5,350,454	5,720,266
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	20,029,741	20,561,275
22	(456.1) Revenues from Transmission of Electricity of Others	172,224,955	154,442,663
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	199,853,631	184,340,605
27	TOTAL Electric Operating Revenues	1,151,304,259	1,165,515,872

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
5,286,839	5,423,442	465,731	462,182	2
				3
5,287,655	5,193,114	62,594	62,186	4
1,484,684	1,836,734	340	364	5
45,087	44,969	619	623	6
				7
				8
				9
12,104,265	12,498,259	529,284	525,355	10
304,042	339,094			11
12,408,307	12,837,353	529,284	525,355	12
				13
12,408,307	12,837,353	529,284	525,355	14

Line 12, column (b) includes \$ -1,459,613 of unbilled revenues.
 Line 12, column (d) includes 47,873 MWH relating to unbilled revenues

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

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

Items greater than \$250,000.00
Connect Charges \$ 476,145

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

Items greater than \$250,000.00
Connect Charges \$ 660,861

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

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
Intracompany Power Sales 780,783

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

Amounts over \$250,000
MD Bill Stabilization Adjustment \$ (4,333,343)
MD Calendar Revenue Normalization 2,522,773
Intercompany Revenue Previously Recorded to Contra-Expense 5,925,278
Intercompany Power Sales 672,818
Consolidated Billing and Account Management Fees 388,364
RPM Auction 14,408,750

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					
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					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

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	R - Residential Sales	5,289,346	645,170,060	461,384	11,464	0.1220
3	PL - Private Area Lighting	5,796	1,759,826	4,347	1,333	0.3036
4	Unbilled Revenue	-8,303	-1,791,708			0.2158
5	Total	5,286,839	645,138,178	465,731	11,352	0.1220
6						
7						
8	442 - Commerical & Industrial Sal					
9	GS - General Services Comm.	5,243,874	262,128,377	58,911	89,013	0.0500
10	GS - General Services Industrial	1,458,070	17,885,119	289	5,045,225	0.0123
11	PL - Private Area Lighting Comm.	14,014	4,301,251	3,683	3,805	0.3069
12	PL - Private Area Lighting Ind.	317	69,464	51	6,216	0.2191
13	Unbilled Revenue Comm.	29,767	153,806			0.0052
14	Unbilled Revenue Ind.	26,297	139,169			0.0053
15	Total	6,772,339	284,677,186	62,934	107,610	0.0420
16						
17	444 - Public Street & Highway Lig					
18	SI - Street Lighting	44,975	13,813,594	619	72,658	0.3071
19	Unbilled Revenue	112	39,120			0.3493
20	Total	45,087	13,852,714	619	72,838	0.3072
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	12,056,392	945,127,691	529,284	22,779	0.0784
42	Total Unbilled Rev.(See Instr. 6)	47,873	-1,459,613	0	0	-0.0305
43	TOTAL	12,104,265	943,668,078	529,284	22,869	0.0780

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

2. Enter the name of the purchaser in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

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	PECO Energy	RQ	2			
2	PJM Interconnection	OS	PJM			
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

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)		
860		42,211		42,211	1
303,182		7,740,339		7,740,339	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
860	0	42,211	0	42,211	
303,182	0	7,740,339	0	7,740,339	
304,042	0	7,782,550	0	7,782,550	

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	469,514,497	479,405,666
77	(556) System Control and Load Dispatching	1,806,887	1,187,926
78	(557) Other Expenses	7,398,780	-2,744,582
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	478,720,164	477,849,010
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	478,720,164	477,849,010
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,099,320	3,689,713
84			
85	(561.1) Load Dispatch-Reliability	234,321	229,430
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	570,133	635,336
87	(561.3) Load Dispatch-Transmission Service and Scheduling	102,562	117,128
88	(561.4) Scheduling, System Control and Dispatch Services	4,791	14,154
89	(561.5) Reliability, Planning and Standards Development	116,977	164,385
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,191	4,144
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	4,165,708	11,044,373
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	10,295,003	15,898,663
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	76,182	88,219
102	(569) Maintenance of Structures	40,603	32,028
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	26,590	30,450
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	5,862,586	4,083,783
108	(571) Maintenance of Overhead Lines	4,338,850	7,693,142
109	(572) Maintenance of Underground Lines	-60,203	
110	(573) Maintenance of Miscellaneous Transmission Plant	506,197	701,481
111	TOTAL Maintenance (Total of lines 101 thru 110)	10,790,805	12,629,103
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	21,085,808	28,527,766

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	7,993	11,585
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	7,993	11,585
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)	7,993	11,585
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	5,616,146	9,731,665
135	(581) Load Dispatching	4,631,218	4,213,145
136	(582) Station Expenses	41,736	13,539
137	(583) Overhead Line Expenses	1,572,902	1,519,204
138	(584) Underground Line Expenses	1,917,926	1,806,042
139	(585) Street Lighting and Signal System Expenses		-6,656
140	(586) Meter Expenses	4,205,525	3,202,839
141	(587) Customer Installations Expenses	384,301	314,266
142	(588) Miscellaneous Expenses	12,742,333	8,939,693
143	(589) Rents	1,646,858	1,707,365
144	TOTAL Operation (Enter Total of lines 134 thru 143)	32,758,945	31,441,102
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	839,227	1,985,998
147	(591) Maintenance of Structures	4,452	7,726
148	(592) Maintenance of Station Equipment	5,250,761	6,280,452
149	(593) Maintenance of Overhead Lines	38,609,937	28,981,613
150	(594) Maintenance of Underground Lines	3,139,642	5,092,534
151	(595) Maintenance of Line Transformers	932,990	1,563,145
152	(596) Maintenance of Street Lighting and Signal Systems	2,279,184	2,687,149
153	(597) Maintenance of Meters	616,414	1,101,968
154	(598) Maintenance of Miscellaneous Distribution Plant	2,430,755	1,595,195
155	TOTAL Maintenance (Total of lines 146 thru 154)	54,103,362	49,295,780
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	86,862,307	80,736,882
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	1,223,470	1,380,382
161	(903) Customer Records and Collection Expenses	44,688,121	46,768,268
162	(904) Uncollectible Accounts	3,121,451	4,672,431
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	49,033,042	52,821,081

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	6,852,174	7,190,369
169	(909) Informational and Instructional Expenses	381,904	861,722
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	7,234,078	8,052,091
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	3,155,256	3,563,640
182	(921) Office Supplies and Expenses	4,537,463	5,964,905
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	64,762,078	74,855,427
185	(924) Property Insurance	423,114	491,763
186	(925) Injuries and Damages	831,107	1,262,692
187	(926) Employee Pensions and Benefits	11,305,901	7,999,345
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	4,168,474	4,418,266
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	731,040	383,314
192	(930.2) Miscellaneous General Expenses	7,554,140	7,980,151
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	97,468,573	106,919,503
195	Maintenance		
196	(935) Maintenance of General Plant	187,098	19,478
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	97,655,671	106,938,981
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	740,599,063	754,937,396

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	Direct Energy Business Marketing, 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	TransCanada Power Marketing LTD	OS				
10	Vitol Inc.	OS				
11	PECO Energy Company	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 Farm, LLC	LU				
3	Other RECs	OS				
4	Altre, LLC	OS				
5	Carbon Solutions Group, LLC	OS				
6	InClimate	OS				
7	Kelly Creek Wind, LLC	OS				
8	White Oaks Solar Energy LLC	OS				
9	Delaware Sustainable Energy Utility	OS				
10	SREC Trade, Inc	OS				
11	Washington Gas (WGL Energy)	OS				
12	ICAP Energy LLC	OS				
13	Amerex Brokers LLC	OS				
14	TFS Energy Futures LLC	OS				
	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)	
53,519			503,266	2,173,039	71,344,239	74,020,544	1
48,556				2,329,513		2,329,513	2
78,094				4,362,176		4,362,176	3
820,879				48,419,050		48,419,050	4
1,534,503				69,643,185		69,643,185	5
44,616				6,400,816		6,400,816	6
2,557,252				137,728,191		137,728,191	7
426,719				22,904,125		22,904,125	8
584,216				32,988,894		32,988,894	9
344,999				32,018,107		32,018,107	10
164				8,053		8,053	11
			1,758,020			1,758,020	12
					224,182	224,182	13
116,289				11,015,639		11,015,639	14
6,796,699			2,261,286	395,623,911	71,629,300	469,514,497	

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)	
85,489				7,500,017		7,500,017	1
101,404				8,653,161		8,653,161	2
				813,668		813,668	3
				255,608		255,608	4
				1,200		1,200	5
				141,587		141,587	6
				122,000		122,000	7
				2,489,666		2,489,666	8
				5,481,896		5,481,896	9
				15,146	1,765	16,911	10
				159,174		159,174	11
					23,888	23,888	12
					5,306	5,306	13
					29,920	29,920	14
6,796,699			2,261,286	395,623,911	71,629,300	469,514,497	

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

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

PJM Interconnection, LLC	
Balancing Operating Reserve	\$ 28,523
Balancing Operating Reserve for Load Response	41
Day-ahead Scheduling Reserve	4,289
Load Reconciliation for Balancing Operating Reserve	601
Load Reconciliation for Day-ahead Scheduling Reserve	(27)
Load Reconciliation for Non- Synchronized Reserve	103
Load Reconciliation for Reactive Services	288
Load Reconciliation for Regulation & Frequency Response Service	1,870
Load Reconciliation for Synchronized Reserve	441
Network Integration Transmission Service	71,226,084
Non- Synchronized Reserve	211
Reactive Services	84
Reactive Supply & Voltage Control from Generation	10,286
Regulation & Frequency Response Service	3,598
Synchronized Reserve	1,841
PJM Customer Payment Default	66,006
	\$ 71,344,239

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, 2019.

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

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, 2019.

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.

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

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: I
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 Maryland.

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.: 10 Column: I
Represents broker fees on purchases of renewable energy credits.

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.: 12 Column: b
Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.1 Line No.: 12 Column: I
Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.1 Line No.: 13 Column: b
Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.1 Line No.: 13 Column: I
Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.1 Line No.: 14 Column: b
Represents broker fees on purchases of renewable energy credits.

Schedule Page: 326.1 Line No.: 14 Column: I
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	AES NewEnergy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
8	Agera Energy, LLC - DE	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
9	Agera Energy, LLC - MD	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	Atlantic Energy MD, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
15	Atlantic Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
16	BlueStar Energy Services, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
17	BOC Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
18	Champion Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
19	Clearview Electric (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
20	Clearview Electric (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
21	Commerce Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
22	Constellation NewEnergy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
23	Delmarva Power (DEN)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
24	Delmarva Power (MDN)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
25	Direct Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
26	Discount Energy Group LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
27	East Coast Power & Gas of New Jersey LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
28	EDF Energy Services, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
29	ELIGO	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
30	Energy Me - DE	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
31	Energy Me - MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
32	Energy Plus Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
33	Ethical Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
34	First Point Power, LLC (DE)	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	First Point Power, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
2	Freepoint Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
3	GDF Suez Retail Energy Solutions, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
4	GEXA Energy Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
5	GEXA Energy Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
6	Great American Power, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
7	Green Mountain Energy Company (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
8	Greenlight Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
9	Hess Energy Marketing, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
10	Horizon Power & Light LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
11	Hudson Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
12	IDT Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
13	Inspire Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
14	Josco Energy USA LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
15	Kuehne Chemical Co	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
16	Liberty Power Corp	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
17	Liberty Power Holdings, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
18	LifeEnergy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
19	Major Energy Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
20	Maryland Gas & Electric	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
21	MidAmerican Energy Services, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
22	MP2 Energy NE LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
23	NextEra Energy Services Delaware, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
24	NextEra Energy Services Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
25	Palmco Power LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
26	Palmco Power LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
27	PBF Power Marketing, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
28	Perigee Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
29	Plymouth Rock Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
30	PP&L EnergyPlus Co , LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
31	PP&L EnergyPlus Co , LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
32	Public Power of MD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
33	Reliant Energy Northeast LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
34	ResCom Energy LLC	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	Residents Energy, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
2	Sempra Energy, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
3	SFE Energy Maryland, Inc	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
4	SmartEnergy Holdings, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
5	SmartEnergy Holdings, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
6	Source Power & Gas LLC - DE	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
7	Sperian Energy Corporation	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
8	Star Energy Partners, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
9	Starion Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
10	Stategic Energy LTD	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
11	StateWise Energy Maryland, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
12	Stream Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
13	Stream Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
14	SunSea	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
15	Texas Retail Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
16	Titan Gas, LLC	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
17	UGI Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
18	Viridian Energy	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
19	Washington Gas Energy Services	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
20	XOOM Energy, LLC (DE)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
21	XOOM Energy, LLC (MD)	PJM Interconnection, LLC	PJM Interconnection, LLC	OS
22				
23				
24				
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 Tarrif	DPL SYSTEM	DPL SYSTEM		11,187		6
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2		7
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		90,793		8
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		66,032		9
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		7,680		10
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		5,019		11
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		5,751		12
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		1,288		13
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		3,229		14
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		12		15
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		42,394		16
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		229,343		17
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		106,181		18
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		9,934		19
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		6,688		20
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		54,596		21
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		1,744,852		22
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		-14,108		23
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		-21,105		24
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		587,081		25
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		703		26
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		249,517		27
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		36,611		28
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		811		29
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		1,417		30
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,482		31
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		5,011		32
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		18,771		33
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,497		34
			0	6,304,360		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 Tarrif	DPL SYSTEM	DPL SYSTEM		578		1
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		22,379		2
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		241,462		3
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		203,224		4
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		43,046		5
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		363		6
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,909		7
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		3		8
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		12,490		9
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		7,380		10
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,792		11
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		5,737		12
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		7,192		13
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		46		14
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		68,209		15
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		16,001		16
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		86,522		17
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		31,641		18
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,037		19
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		14,342		20
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		146,500		21
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		2,334		22
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,572		23
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		352		24
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		3,361		25
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		3,109		26
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		248,646		27
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		486		28
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,415		29
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		509,641		30
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		51,150		31
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		33,314		32
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		160,670		33
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		617		34
			0	6,304,360		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 Tarrif	DPL SYSTEM	DPL SYSTEM		3,224		1
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		249,509		2
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		20,480		3
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		18,163		4
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		12,578		5
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		1,472		6
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,651		7
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		1,920		8
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		4,521		9
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		153,938		10
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		204		11
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		7,859		12
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		5,148		13
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		52		14
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		35,385		15
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		126		16
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		17,485		17
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		8,305		18
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		524,092		19
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		11,093		20
PJM Tarrif	DPL SYSTEM	DPL SYSTEM		27,966		21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	6,304,360		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.
		1,205,341	1,205,341	1
		1,456,518	1,456,518	2
		163,480,271	163,480,271	3
		4,435,096	4,435,096	4
		1,647,729	1,647,729	5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
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				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	0	172,224,955	172,224,955	

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
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
0	0	172,224,955	172,224,955	

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
				14
				15
				16
				17
				18
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				32
				33
				34
0	0	172,224,955	172,224,955	

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) 03/27/2020	Year/Period of Report 2019/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), PECO Energy for EHV/TEF (Extra High Voltage/Transmission Enhancement Facilities) agreements and Exelon (Generation and Business Services Company) for a lease agreement.

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					
14					
15					
16					
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25					
26					
27					
28					
29					
30					
31					
32					
33					
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	288,798
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	91,157
7	Board of Director Expenses	73,289
8	Research, Development,	
9	and Demonstration, including Memberships	449,405
10	DE Environmental & Low Income and MD Universal Fund	6,661,139
11	Credit Card Accruals	-9,648
12	Miscellaneous	
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
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41		
42		
43		
44		
45		
46	TOTAL	7,554,140

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			1,835,889		1,835,889
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	43,965,830				43,965,830
8	Distribution Plant	69,785,468				69,785,468
9	Regional Transmission and Market Operation					
10	General Plant	9,048,656				9,048,656
11	Common Plant-Electric	4,227,825		3,998,422		8,226,247
12	TOTAL	127,027,779		5,834,311		132,862,090

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	53,865	55.00	-20.00	2.00	S5	
15	353	621,044	50.00	-10.00	2.10	R2	
16	354	73,958	55.00	-25.00	2.27	R3	
17	355	531,305	38.00	-45.00	3.68	S0.5	
18	356	307,357	50.00	-50.00	2.60	S1	
19	357	45,528	40.00		2.50	R4	
20	358	23,195	40.00		2.50	R3	
21	359	731	50.00		2.00	R3	
22	SUBTOTAL	1,690,050					
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	23,590	65.00	-10.00	1.27	R4	
27	361 MD	18,723	60.00	-15.00	1.79	R2	
28	362 DE	245,055	45.00	-20.00	2.08	R2	
29	362 MD	176,580	52.00	-25.00	2.02	R2.5	
30	364 DE	104,967	55.00	-100.00	2.25	R2	
31	364 MD	115,131	55.00	-125.00	2.99	R2	
32	365 DE	166,403	55.00	-100.00	1.53	R1.5	
33	365 MD	197,196	58.00	-100.00	2.30	R0.5	
34	366 DE	22,950	70.00	-5.00	0.84	S3	
35	366 MD	820	50.00		1.65	R3	
36	367 DE	210,157	52.00	-40.00	1.82	R3	
37	367 MD	176,083	40.00	-20.00	2.83	R3	
38	368 DE	299,840	45.00	-50.00	1.77	R2	
39	368 MD	257,397	35.00	-50.00	3.57	R1	
40	369.1 DE	18,345	65.00	-120.00	0.81	R4	
41	369.1 MD	8,600	65.00	-75.00	2.17	R4	
42	369.2 DE	96,304	55.00	-60.00	1.36	S3	
43	369.2 MD	85,350	45.00	-25.00	2.21	S6	
44	370 DE	13,354	25.00	-3.00	2.77	L0.5	
45	370 MD	5,745	30.00		4.72	S3	
46	370.1 DE	68,665	15.00	-3.00	8.13	S2	
47	370.1 MD	43,222	15.00		11.18	S3	
48	371.1 DE	30,973	18.00	-40.00	8.20	R2	
49	371.1 MD	11,461	42.00	-50.00	2.83	S1.5	
50	373 DE	55,824	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	11,954	33.00	-30.00	3.81	SC	
13	SUBTOTAL	2,472,359					
14	GENERAL						
15	390 DE	5,587	50.00	-10.00	1.01	R3	
16	390 MD	25,823	35.00	-10.00	3.48	R1.5	
17	391.1 DE	613	19.00	5.00	5.38	L2	
18	391.2 DE	2,306	20.00		5.65	SQ	
19	391.1 MD	688	15.00		6.68	SQ	
20	391.3 MD	1,099	5.00		10.00	SQ	
21	391.3 DE	3,947	5.00		21.49	SQ	
22	393 DE	505	25.00		19.74	SQ	
23	394 DE	8,819	25.00		6.32	SQ	
24	394.1 DE	-1	36.00		2.78	L1	
25	394 MD	9,730	15.00		6.67	SQ	
26	395 DE	92	20.00		15.46	SQ	
27	397 MD	12,527	35.00	-10.00	3.09	S3	
28	397 DE	65,528	25.00		4.13	L3	
29	397.1 MD	26,138	15.00		6.90	S3	
30	397.1 DE	16,727	15.00		6.98	S2	
31	397.3 MD	28,664	15.00		6.67	SQ	
32	397.2 DE	4,970	15.00		6.89	SQ	
33	398 DE	1,029	20.00		5.74	SQ	
34	398 MD	1,946	15.00		6.67	SQ	
35	SUBTOTAL	216,737					
36	COMMON						
37	390.3	45,649	75.00	-5.00	0.80	S1.5	
38	390.3a	7,151	75.00	-5.00	0.73	S1.5	
39	390.3b	781	40.00	-20.00	-0.09	R2	
40	391.1	5,418	20.00		5.38	SQ	
41	391.3	6,295	5.00		36.45	SQ	
42	393	158	25.00		6.27	SQ	
43	394	5,887	25.00		6.56	SQ	
44	397.1	492	20.00	5.00	4.75	L2	
45	397.1a	19,479	15.00		6.63	S2	
46	397.3	4,408	15.00		0.09	SQ	
47	398	7,927	20.00		5.22	SQ	
48	398.1a	1,028	20.00		5.74	SQ	
49	SUBTOTAL	104,673					
50							

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		27	27	
3	2017 DE Base Rate Case 17 0977		47,333	47,333	
4	DE Rate Case No 13-115		569	569	
5	General Regulation Legal		281,616	281,616	
6	DE Electric DSIC		100	100	
7					
8	Maryland				
9	2016 MD Base Rate Case 9424		70,337	70,337	
10	2017 MD Base Rate Case 9455		19,313	19,313	
11	2018/2019 DPL MD Base Rate Case		88,307	88,307	
12	PC44 DPL MD		357,146	357,146	
13	Regulatory Commission Expense		34,232	34,232	
14	MD Grid Future Proceeding		19,725	19,725	
15	General Regulation Legal		183,139	183,139	
16					
17	Transmission:				
18	ER05-515 Annual Rate Updates FERC Transmission		197,731	197,731	
19	DEMEC Formal Challenge - FERC Transmission		882	882	
20	EL15-79 (TranSource) - FERC Transmission		3,713	3,713	
21	DPL SECA EL02 - FERC Transmission		3,135	3,135	
22					
23	Regulatory Tax Assessment	2,861,169		2,861,169	
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	2,861,169	1,307,305	4,168,474	

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			1
Electric	928	27		0			2
Electric	928	47,333		0			3
Electric	928	569		0			4
Electric	928	281,616		0			5
Electric	928	100		0			6
				0			7
				0			8
Electric				928	70,337		9
Electric				928	19,313		10
Electric	928	88,307		0			11
Electric	928	357,146		0			12
Electric	928	34,232		0			13
Electric	928	19,725		0			14
Electric	928	183,139		0			15
				0			16
				0			17
Electric	928	197,731		0			18
Electric	928	882		0			19
Electric	928	3,713		0			20
Electric	928	3,135		0			21
				0			22
Electric	928	2,861,169					23
							24
							25
							26
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							29
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							43
							44
							45
		4,078,824			89,650		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. Electric RD&D Performed Internally:	
2	(2) Transmission and (3) Distribution	Other - 9 Projects (less than \$50K)
3		
4	B. Electric RD&D Performed Externally:	
5	(1) Research Support to Electric Power	Membership - EPRI
6	Research Institute	
7		
8		
9	(4) Research Support to Others	Membership - National Electric
10		Energy, Testing, Research, and
11		Application Center
12		(Georgia Tech Research Corp)
13		
14		
15		
16		Membership - Power Systems Engineering Research Center
17		(Arizona State University)
18		
19		Membership - Centre for Energy Advancement through Technical
20		Innovation (CEATI)
21		Membership - Northeast Gas Association
22		
23		Membership - Utility Health Sciences Group
24		
25		Membership - The Electric Vehicle Coalition of New Jersey
26		(ChargeVC Inc)
27		
28		Membership -ELECTRIC DRIVE TRANSPORTATION ASSOC
29		
30		Membership-CU Boulder College of Engineering Construction Safety
31		Research Alliance
32		(University of Colorado Foundation)
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)		
					1
59,307		930.2	59,307		2
					3
					4
	301,727	930.2	301,727		5
					6
					7
					8
					9
					10
					11
	11,488	930.2	11,488		12
					13
					14
					15
					16
	3,419	930.2	3,419		17
					18
	20,933	930.2	20,933		19
					20
	14,113	930.2	14,113		21
					22
	5,029	930.2	5,029		23
					24
	12,370	930.2	12,370		25
					26
					27
	20,016	930.2	20,016		28
					29
	1,003	930.2	1,003		30
					31
					32
59,307	390,098		449,405		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	1,505,914		
49	Administrative and General	838		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	1,938,516		
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)	502,704		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru	763,823		
56	Transmission (Lines 35 and 47)	1,310,597		
57	Distribution (Lines 36 and 48)	7,636,191		
58	Customer Accounts (Line 37)	462,245		
59	Customer Service and Informational (Line 38)	17,151		
60	Sales (Line 39)	185,192		
61	Administrative and General (Lines 40 and 49)	827,927		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	11,705,830	86,985	11,792,815
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	54,464,686	3,619,905	58,084,591
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	40,534,223	1,895,692	42,429,915
69	Gas Plant	5,706,026	221,648	5,927,674
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	46,240,249	2,117,340	48,357,589
72	Plant Removal (By Utility Departments)			
73	Electric Plant	3,863,291	191,173	4,054,464
74	Gas Plant	440,866	15,872	456,738
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,304,157	207,045	4,511,202
77	Other Accounts (Specify, provide details in footnote):			
78	Expenses from Merchandising, Jobbing & Contract Work - 416	1,111,458	88,078	1,199,536
79	Expenses of Non-Utility Operations - 417.1	14,300	103,134	117,434
80	Donations - 426.1	47,652	1,054	48,706
81	Exp. For Certain Civic, Political & Related Activities	14,757	1,411	16,168
82	Other Deductions - 426.5	29,969		29,969
83				
84				
85				
86				
87				
88				
89				
90	Plant Held for Future -105	1,308		1,308
91				
92				
93				
94				
95	TOTAL Other Accounts	1,219,444	193,677	1,413,121
96	TOTAL SALARIES AND WAGES	106,228,536	6,137,967	112,366,503

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) 03/27/2020	Year/Period of Report End of <u>2019/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

- 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.
- 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.
- 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.
- 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	34,818,754	16,585,576	-	-	51,404,330
389.1	1,621,110	-	-	-	1,621,110
390.3	51,975,463	4,123,360	(119,065)	-	55,979,758
391.1	5,648,217	(18,130)	(423,570)	-	5,206,517
391.3	2,978,787	3,525,056	-	-	6,503,843
393	196,355	-	(76,349)	-	120,006
394	6,423,759	-	(1,072,799)	-	5,350,960
397	24,084,413	152,872	-	(106,408)	24,130,877
398	7,988,892	1,030,195	(99,319)	28,038	8,947,806
	136,472,250	25,398,929	(1,791,102)	(78,370)	160,001,707

Acct	Electric	Gas	Total Common Utility Plant	E = 83.03% G = 16.97%
301	611,516	124,984	736,500	
303	42,681,015	8,723,315	51,404,330	
389.1	1,346,008	275,102	1,621,110	
390.3	46,479,993	9,499,765	55,979,758	
391.1	4,322,971	883,546	5,206,517	
391.3	5,400,141	1,103,702	6,503,843	
393	99,641	20,365	120,006	
394	4,442,902	908,058	5,350,960	
397	20,035,867	4,095,010	24,130,877	
398	7,429,363	1,518,443	8,947,806	
	132,849,417	27,152,290	160,001,707	

Accumulated Provision for Depreciation of Common Utility Plant
DPL
12/31/2019

	Total Common	Electric	Gas
Balance at Beginning of Year	68,710,261	56,225,607	12,484,654

Depreciation Provision for the

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) 03/27/2020	Year/Period of Report End of <u>2019/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

- 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.
- 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.
- 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.
- 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.

Year Charged to:			
403 Depreciation Expense	3,825,025	3,175,919	649,106
Net Charges for Plant Retired:			
Book Charges for Plant Retired	(1,791,104)	(1,487,153)	(303,951)
Cost of Removal, Net of Salvage	(855,249)	(710,113)	(145,136)
Other Debit or Credit Items:			
Transfers / Adjustments	292,757	243,076	49,681
Gain from Sale	-	-	-
Electric & Gas Allocator Adjustment	-	824,522	(824,522)
Balance at End of Year	70,181,690	58,271,858	11,909,832
Accumulated Provision for Amortization of Common Utility Plant			
DPL			
12/31/2019			
	Total Common	Electric	Gas
Balance at Beginning of Year	18,598,919	15,219,495	3,379,424
Depreciation Provision for the			
Year Charged to:			
404 Amortization Expense	6,082,535	5,050,328	1,032,207
Net Charges for Plant Retired:			
Book Charges for Plant Retired			
Cost of Removal, Net of Salvage			
Other Debit or Credit Items			
Transfers / Adjustments	-	223,188	(223,188)
Electric & Gas Allocator Adjustment			
Balance at End of Year	24,681,454	20,493,011	4,188,443

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)	621,296	1,609,708	1,907,687	2,240,758
3	Net Sales (Account 447)	(2,821,339)	(4,866,177)	(5,852,900)	(7,740,339)
4	Transmission Rights	17,260,860	34,806,474	52,983,862	71,226,084
5	Ancillary Services	14,027	127,889	37,153	52,208
6	Other Items (list separately)				
7	Demand	268,159	350,198	415,756	501,554
8					
9					
10					
11					
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43					
44					
45					
46	TOTAL	15,343,003	32,028,092	49,491,558	66,280,265

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	6,796,699	MWH	25,594	13,101,059	MWH	1,456,518
2	Reactive Supply and Voltage		MWH	10,286			
3	Regulation and Frequency Response		MWH	5,468			
4	Energy Imbalance						
5	Operating Reserve - Spinning		MWH	2,282			
6	Operating Reserve - Supplement						
7	Other		MWH	34,140			
8	Total (Lines 1 thru 7)	6,796,699		77,770	13,101,059		1,456,518

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 2 Column: b

The number of units reported on Line #2, Column (b) is 6,796,699 MWH.

Schedule Page: 398 Line No.: 3 Column: b

The number of units reported on Line #3, Column (b) is 6,796,699 MWH.

Schedule Page: 398 Line No.: 5 Column: b

The number of units reported on Line #5, Column (b) is 6,796,699 MWH.

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

The number of units reported on Line #7, Column (b) is 6,796,699 MWH.

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

Other Ancillary Services Purchased are as follows:

Balancing Operating Reserve	\$ 29,165
Day-ahead Scheduling Reserve	4,262
Non-Synchronized Reserve	314
Reactive Services	399
	\$ 34,140

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	3,773	31	800	2,777	996				
2	February	3,442	2	800	2,584	857				
3	March	3,084	7	700	2,219	866				
4	Total for Quarter 1				7,580	2,719				
5	April	2,445	2	800	1,673	772				
6	May	3,203	29	1700	2,191	1,012				
7	June	3,509	28	1700	2,479	1,030				
8	Total for Quarter 2				6,343	2,814				
9	July	4,041	21	1800	2,992	1,049				
10	August	3,713	22	1800	2,632	1,081				
11	September	3,468	12	1700	2,367	1,101				
12	Total for Quarter 3				7,991	3,231				
13	October	3,277	2	1700	2,284	993				
14	November	2,816	14	700	1,970	846				
15	December	3,152	20	800	2,215	937				
16	Total for Quarter 4				6,469	2,776				
17	Total Year to Date/Year				28,383	11,540				

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									

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	12,104,265
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	860
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	303,182
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	19,473
7	Other		27	Total Energy Losses	673,279
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	13,101,059
9	Net Generation (Enter Total of lines 3 through 8)				
10	Purchases	6,796,699			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	6,304,360			
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)	6,304,360			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	13,101,059			

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	1,283,107	36,409	3,773	31	800
30	February	1,075,305	30,114	3,442	2	800
31	March	1,074,516	32,062	3,084	7	700
32	April	855,876	33,486	2,445	2	800
33	May	959,023	25,934	3,203	29	1700
34	June	1,101,519	26,145	3,509	28	1700
35	July	1,379,227	13,019	4,041	21	1800
36	August	1,262,457	13,667	3,713	22	1800
37	September	1,054,557	13,743	3,468	12	1700
38	October	900,930	22,700	3,277	2	1700
39	November	997,928	28,318	2,816	14	700
40	December	1,156,614	28,445	3,152	20	800
41	TOTAL	13,101,059	304,042			

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
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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
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			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						
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14						
15						
16						
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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
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						46

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	500 KV Line (wholly owned)		500.00	500.00	SC Steel	15.55		3
2								
3	230 KV Lines		230.00	230.00	Various	387.32	83.64	25
4								
5	138 KV Lines		138.00	138.00	Various	503.95	82.53	80
6								
7	69 KV Lines		69.00	69.00	Various	556.19	13.02	73
8								
9	Underground Lines	5.46 mi. / 138, 2.21 mi/69				7.68		19
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	2,658.51	345.36	318

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	Red Lion	Hope Creek	500.00	500.00	steel towers	3.79		1
2	Keeney	Rock Springs	500.00	500.00	steel towers	3.79		1
3	Keeney	Red Lion	500.00	500.00	steel towers	7.98		1
4	Keeney	Steele	230.00	230.00	steel towers		57.20	1
5	Indian River	Piney Grove	230.00	230.00	wood H frame	25.83		1
6	Red Lion	Cedar Creek	230.00	230.00	steel poles	20.95		1
7	Cedar Creek	Milford	230.00	230.00	steel poles	42.84		1
8	Red Lion	Cartanza	230.00	230.00	steel poles	33.24	4.31	1
9	Cartanza	Milford	230.00	230.00	steel poles	26.50		1
10	Milford	Indian River	230.00	230.00	steel poles	26.37		1
11	Milford	Cool Spring	230.00	230.00	wood H frame	14.95		1
12	Indian River	Cool Spring	230.00	230.00	wood H frame	11.54		1
13	Milford	Steele	230.00	230.00	wood H frame	23.39		1
14	Colora	Nottingham	230.00	230.00	steel towers	1.76		1
15	Colora	Crest	230.00	230.00	steel poles	7.57		1
16	Claymont Sub	Linwood	230.00	230.00	steel poles	0.99		1
17	Edgemoor	Linwood	230.00	230.00	steel poles		8.10	1
18	Colora	Conowingo	230.00	230.00	steel poles	1.92		1
19	Crest	Cecil	230.00	230.00	steel poles	8.45		1
20	Keeney	Steele	230.00	230.00	steel towers	57.07		1
21	Keeney	Harmony	230.00	230.00	steel poles	6.14		1
22	Keeney	Red Lion	230.00	230.00	steel towers	8.05		1
23	Harmony	Edge Moor	230.00	230.00	steel poles	11.87		1
24	Keeney	Harmony	230.00	230.00	steel poles	9.30	0.20	1
25	Edge Moor	Claymont	230.00	230.00	steel poles	7.07		1
26	Hay Road	Red Lion	230.00	230.00	steel poles	10.72	13.83	1
27	Cartanza	Garrison	230.00	230.00	steel poles	2.63		1
28	Steele	Vienna	230.00	230.00	wood H frame	28.17		1
29	Church	Steele	138.00	138.00	steel poles	25.69		1
30	Milford	Milford City	138.00	138.00	wood poles	0.24		1
31	Nelson	Indian River	138.00	138.00	wood H frame	21.41		1
32	Cheswold	Felton	138.00	138.00	wood poles	14.38		1
33	Indian River	Robinsonville	138.00	138.00	wood poles	11.74		1
34	Robinsonville	Rehoboth	138.00	138.00	steel poles	6.90		1
35	Vienna	Nelson	138.00	138.00	wood H frame	13.68		1
36					TOTAL	2,658.51	345.36	318

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	Felton	South Harrington	138.00	138.00	wood poles	8.49		1
2	Vienna	Vienna (AT20)	138.00	138.00	wood poles	0.17		1
3	Easton	Steele	138.00	138.00	steel poles	23.62		1
4	Loretto	Kings Creek	138.00	138.00	wood H frame	7.18		1
5	Kings Creek	Pocomoke	138.00	138.00	wood H frame	9.14		1
6	Indian River	Bishop	138.00	138.00	steel poles	12.33		1
7	Indian River	Bishop	138.00	138.00	steel poles	7.24	5.18	1
8	Oak Hall	Eastern Shore Solar	138.00	138.00	steel poles	0.07		1
9	Church	Carville	138.00	138.00	steel poles	0.13	17.58	1
10	Kings Creek	Great Bay	138.00	138.00	steel poles	0.10		1
11	Ocean Bay	138th Street	138.00	138.00	wood poles	2.97		1
12	138th Street	Bethany	138.00	138.00	steel poles	6.13		1
13	Roxana	Bethany	138.00	138.00	wood H frame	3.65		1
14	Indian River	Roxana	138.00	138.00	wood H frame	8.54		1
15	Indian River AT20	Indian River 138	138.00	138.00	steel poles	0.26		1
16	Indian River AT22	Indian River 138	138.00	138.00	steel poles	0.29		1
17	Steele	Hillsboro	138.00	138.00	wood H frame	7.24		1
18	New Church	Oak Hall	138.00	138.00	wood poles	3.68		1
19	Piney Grove	New Church	138.00	138.00	wood H frame	21.80		1
20	New Church	Oak Hall	138.00	138.00	wood H frame	3.56		1
21	Indian River	Conaway	138.00	138.00	wood H frame	8.50		1
22	Conaway	N. Seaford	138.00	138.00	wood H frame	16.94		1
23	Clayton	Cheswold	138.00	138.00	wood poles	6.63		1
24	N. Seaford	S. Harrington	138.00	138.00	wood poles	16.22		1
25	Clayton	DEMEC	138.00	138.00	steel poles	0.69		1
26	Farmview	Milford	138.00	138.00	wood poles	2.44		1
27	Farmview	S. Harrington	138.00	138.00	wood poles	7.73		1
28	Piney Grove	Loretto	138.00	138.00	wood H frame	9.49		1
29	Bishop	Worcester	138.00	138.00	wood H frame	5.33		1
30	Loretto	Vienna	138.00	138.00	wood H frame	19.44		1
31	Bishop	Ocean Bay	138.00	138.00	wood H frame	9.97		1
32	Pocomoke	Oak Hall	138.00	138.00	wood H frame	8.57		1
33	Hillsboro	Wye Mills	138.00	138.00	wood H frame	8.59		1
34	Wattsville	Oak Hall	138.00	138.00	steel poles	3.91		1
35	Glasgow	Mt Pleasant	138.00	138.00	steel poles	10.99		1
36					TOTAL	2,658.51	345.36	318

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	Red Lion West	Reybold	138.00	138.00	steel poles	1.11		1
2	New Castle	Town of New Castle	138.00	138.00	steel poles	0.40		1
3	Edge Moor	Brandywine	138.00	138.00	steel poles	2.52		1
4	Edge Moor	Christiana	138.00	138.00	steel towers	2.56	0.15	1
5	Keeney	Churchmans	138.00	138.00	steel poles	6.05		1
6	Churchmans	Basin Road	138.00	138.00	steel poles	0.93	2.50	1
7	Mt Pleasant	Townsend	138.00	138.00	steel poles	11.27		1
8	Keeney	Glasgow	138.00	138.00	steel poles	3.33		1
9	New Castle	Hares Corner	138.00	138.00	steel poles	3.68		1
10	Hares corner	Red Lion	138.00	138.00	wood poles	4.48	0.68	1
11	Christiana	New Castle	138.00	138.00	steel towers	0.75	3.46	1
12	Basin Road	Bear	138.00	138.00	wood poles	4.69		1
13	Keeney	Sunset Lake	138.00	138.00	wood poles	2.27		1
14	Red Lion	Reybold	138.00	138.00	steel poles	0.14	1.11	1
15	Glasgow	Cecil	138.00	138.00	steel poles	5.24		1
16	Basin Road	Kiamensi	138.00	138.00	steel towers	3.20		1
17	Basin Road	New Castle	138.00	138.00	steel towers	0.11	2.94	1
18	Keeney	Chapel Street	138.00	138.00	steel poles	1.27	2.82	1
19	Harmony	Chapel Street	138.00	138.00	steel poles	3.32		1
20	Keeney EHV	Keeney 138	138.00	138.00	steel poles	0.25		1
21	Carrcroft	Talleyville	138.00	138.00	wood poles	3.56		1
22	Edgemoor	Carrcroft	138.00	138.00	steel towers	0.84	2.81	1
23	Motiva	Reybold	138.00	138.00	wood poles	0.08		1
24	Carrcroft	West Wilmington	138.00	138.00	steel towers	4.33		1
25	West Wilmington	Silverbrook	138.00	138.00	steel poles	1.97		1
26	Harmony	Kiamensi	138.00	138.00	steel poles	4.23		1
27	Kiamensi	Silverbrook	138.00	138.00	steel towers	2.70	1.00	1
28	Brandywine	Carrcroft	138.00	138.00	steel towers	1.36	2.87	1
29	Red Lion	Bloom Energy	138.00	138.00	steel poles	0.44		1
30	Cedar Creek	Clayton	138.00	138.00	wood poles	9.23		1
31	Townsend	Church	138.00	138.00	steel poles	12.32		1
32	Kiamensi	Milltown	138.00	138.00	wood poles	1.40	1.31	1
33	Milltown	Valley Road	138.00	138.00	wood poles	4.60		1
34	Valley Road	Hockessin	138.00	138.00	wood poles	1.78		1
35	Kiamensi	Hockessin	138.00	138.00	wood poles	6.26		1
36					TOTAL	2,658.51	345.36	318

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	Reybold	Lums Pond	138.00	138.00	wood poles	8.22		1
2	Lums pond	Mt Pleasant	138.00	138.00	wood poles	9.74		1
3	Bear	Sunset Lake	138.00	138.00	wood poles	5.31		1
4	Glasgow	Mt Pleasant	138.00	138.00	steel poles	11.10		1
5	Carville	Wye Mills	138.00	138.00	steel poles	0.12	7.93	1
6	Piney Grove	Wattsville	138.00	138.00	steel poles	0.71	30.19	1
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								
35								
36					TOTAL	2,658.51	345.36	318

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	23,316,490	24,158,720					1
								2
	15,382,105	212,866,293	228,248,398					3
								4
	11,248,373	420,060,331	431,308,704					5
								6
	7,548,675	253,220,820	260,769,495					7
								8
	9,713	67,455,601	67,465,314					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
					4,031,634	253,578	4,285,212	35
	35,396,501	979,624,327	1,015,020,828		4,031,634	253,578	4,285,212	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)	
2505 AACSR								1
2493 ACAR								2
2493 ACAR								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
1590 ACSR								13
795 ACSR								14
1590 ACSR								15
1590 ACSR								16
1590 ACSR								17
795 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 bundled								26
1590 ACSR								27
1590 ACSR								28
1590 ACSR								29
336.4 ACSR								30
477 ACSR								31
954 ACSR								32
954 ACSR								33
954 ACSR								34
954 ACSR								35
	35,396,501	979,624,327	1,015,020,828		4,031,634	253,578	4,285,212	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)	
954 ACSR								1
1590 ACSR								2
996.2 ACSR								3
954 ACSR								4
954 ACSR								5
1590 ACSR								6
1590 ACSR								7
954 ACSR								8
1590 ACSR								9
954 ACSR								10
966.2 ACSR								11
954 ACSR								12
954 ACSR								13
954 ACSS								14
1590 ACSR								15
2000 KCMIL CU								16
954 ACSR								17
954 ACSR								18
477 ACSR								19
556.5 ACSS								20
954 ACSR								21
954 ACSR								22
954 ACSR								23
954 ACSR								24
954 ACSR								25
954 ACSR								26
954 ACSR								27
477 ACSR								28
954 ACSR								29
1590 ACSR								30
954 ACSR								31
954 ACSR								32
954 ACSR								33
954 ACSR								34
1590 ACSR								35
	35,396,501	979,624,327	1,015,020,828		4,031,634	253,578	4,285,212	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)	
954 ACSR								1
954 ACSR								2
954 ACSR								3
954 ACSR								4
1590 ACSR								5
636 ACSR								6
1590 ACSR								7
636 ACSR								8
954 Phoenix								9
954 Phoenix								10
636 ACSR								11
954 ACSR								12
954 ACSR								13
954 ACSR								14
1590 ACSR								15
954 ACSR								16
954 ACSR								17
954 ACSR								18
477 ACSS/TW								19
1590 ACSR								20
477 AA								21
954 ACSR								22
954 ACSR								23
954 ACSR								24
954 ACSR								25
1590 ACSR								26
954 ACSR								27
954 ACSR								28
954 ACSR								29
954 ACSR								30
636 ACSR								31
954 ACSR								32
954 ACSR								33
954 ACSR								34
954 ACSR								35
	35,396,501	979,624,327	1,015,020,828		4,031,634	253,578	4,285,212	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.
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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
1590 ACSR								5
954 ACSR								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
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								28
								29
								30
								31
								32
								33
								34
								35
	35,396,501	979,624,327	1,015,020,828		4,031,634	253,578	4,285,212	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) 03/27/2020	Year/Period of Report 2019/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.: 33 Column: f

Includes 3.15 miles of steel poles as well.

Schedule Page: 422.2 Line No.: 14 Column: i

Includes 954 ACSR as well.

Schedule Page: 422.2 Line No.: 16 Column: f

Includes 0.14 miles of UG as well.

Schedule Page: 422.2 Line No.: 16 Column: i

Includes 1949 ACSS as well.

Schedule Page: 422.2 Line No.: 31 Column: f

Includes 2.81 miles of UG as well.

Schedule Page: 422.2 Line No.: 31 Column: i

Includes KCMIL AL as well.

Schedule Page: 422.3 Line No.: 15 Column: i

Includes 768.2 ACSS as well.

Schedule Page: 422.3 Line No.: 28 Column: f

Includes 1.24 miles of UG as well.

Schedule Page: 422.3 Line No.: 28 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							
13							
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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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									14
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									44

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-Unattd	34.00	4.00	
2	Appleton-Cecil, MD	Distribution-Unattd	34.00	4.00	
3	Basin Road - New Castle, DE	Transmission-Unattd	138.00	69.00	
4	Basin Road - New Castle, DE	Distribution-Unattd	138.00	69.00	
5	Basin Road - New Castle, DE	Distribution-Unattd	138.00	69.00	
6	Beaglin - Salisbury, MD	Distribution-Unattd	69.00	25.00	
7	Bear - New Castle, DE	Distribution-Unattd	138.00	12.00	
8	Bear - New Castle, DE	Distribution-Unattd	138.00	34.00	
9	Bethany - Bethany, DE	Distribution-Unattd	138.00	12.00	
10	Bethany -Bethany, DE	Transmission-Unattd	138.00	69.00	
11	Bethany -Bethany, DE	Distribution-Unattd	69.00	12.00	
12	Bishop - Bishopville, MD	Distribution-Unattd	138.00	25.00	
13	Blue Ball Rd - Elkton, MD	Distribution-Unattd	34.00	4.00	
14	Bohemia-Cecil, MD	Distribution-Unattd	34.00	4.00	
15	Bozman-Bozman, MD	Distribution-Unattd	69.00	25.00	
16	Brandywine -Wilm, DE	Distribution-Unattd	138.00	12.00	
17	Bridgeville -Bridgeville, DE	Distribution-Unattd	69.00	13.09	
18	Brookside -Pencader, DE	Distribution-Unattd	34.00	12.00	
19	Calvert-Cecil, MD	Distribution-Unattd	34.00	4.00	
20	Cambridge - Cambridge, MD	Distribution-Unattd	69.00	24.00	
21	Carrcroft -Brandywine Hd, DE	Transmission-Unattd	138.00	69.00	
22	Carrcroft -Brandywine Hd, DE	Distribution-Unattd	138.00	34.50	
23	Centerville, MD	Distribution-Unattd	138.00	25.00	
24	Cathers-Cecil, MD	Distribution-Unattd	34.00	4.36	
25	Cayots-Cecil, MD	Distribution-Unattd	34.00	4.00	
26	Cecil-Cecil, MD	Distribution-Unattd	138.00	34.00	
27	Cecil-Cecil, MD	Distribution-Unattd	230.00	34.00	
28	Cecil-Cecil, MD	Transmission-Unattd	230.00	138.00	
29	Cecil-Cecil, MD	Distribution-Unattd	34.00	4.16	
30	Cedar Creek -New Castle, DE	Transmission-Unattd	230.00	138.00	
31	Cedar Creek -New Castle, DE	Distribution-Unattd	138.00	25.00	
32	Cedar Neck, DE	Distribution-Unattd	69.00	12.47	
33	Centreville, MD	Distribution-Unattd	69.00	12.47	
34	Chapel St, Newark, DE	Distribution-Unattd	138.00	34.00	
35	Chapel St -Newark, DE	Distribution-Unattd	34.50	12.00	
36	Charles-Cecil, MD	Distribution-Unattd	34.00	4.00	
37	Chesapeake City-Cecil, MD	Distribution-Unattd	34.00	4.00	
38	Chestertown - Chestertown, MD	Distribution-Unattd	69.00	24.00	
39	Chestnut Run -Christiana Hd, DE	Distribution-Unattd	34.00	12.00	
40	Cheswold -Cheswold, DE	Distribution-Unattd	138.00	25.00	

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	Cheswold -Cheswold, DE	Transmission-Unattd	138.00	69.00	
2	Christiana -Wilm DE	Distribution-Unattd	138.00	12.00	
3	Church-Millington, MD	Transmission-Unattd	138.00	69.00	
4	Church-Millington, MD	Distribution-Unattd	69.00	25.00	
5	Churchmans - New Castle, DE	Distribution-Unattd	138.00	12.00	
6	Claymont - Brandywine Hd, DE	Transmission-Unattd	230.00	69.00	
7	Clayton -Clayton, DE	Distribution-Unattd	25.00	4.00	
8	Clayton -Clayton, DE	Distribution-Unattd	138.00	24.00	
9	Colora-Cecil, MD	Distribution-Unattd	230.00	34.00	
10	Cool Spring - Milton, DE	Transmission-Unattd	230.00	69.00	
11	Cowlane-Cecil, MD	Distribution-Unattd	34.00	4.00	
12	Crest, Cecil Co., MD	Distribution-Unattd	230.00	34.00	
13	Crisfield-Crisfield, MD	Distribution-Unattd	69.00	25.00	
14	Crisfield-Crisfield, MD	Distribution-Unattd	69.00	12.47	
15	Crisfield-Crisfield, MD	Distribution-Unattd	25.00	4.00	
16	Crothers Road, Cecil Co., MD	Distribution-Unattd	34.00	4.00	
17	Culver-Ocean City, MD	Distribution-Unattd	69.00	12.47	
18	Darley -Brandywine Hd, DE	Distribution-Unattd	69.00	12.47	
19	Darley -Brandywine Hd, DE	Distribution-Unattd	69.00	34.00	
20	Darlington-Harford, MD	Distribution-Unattd	34.00	4.36	
21	Dublin-Harford, MD	Distribution-Unattd	34.00	4.16	
22	East New Market, MD	Distribution-Unattd	69.00	13.09	
23	Easton-Easton, MD	Distribution-Unattd	69.00		
24	Easton-Easton, MD	Transmission-Unattd	138.00	69.00	
25	Easton-Easton, MD	Distribution-Unattd			
26	Edge Moor - Brandywine , DE	Distribution-Unattd	138.00	12.47	
27	Edge Moor - Brandywine, DE	Transmission-Unattd	138.00	69.00	
28	Edge Moor - Brandywine, DE	Transmission-Unattd	230.00	138.00	
29	Edge Moor - Brandywine, DE	Distribution-Unattd	69.00	12.00	
30	Elkneck-Cecil, MD	Distribution-Unattd	34.00	4.00	
31	Elkton-Cecil, MD	Distribution-Unattd	34.00	4.00	
32	Faulk Rd Sub-Brandywine Hd, DE	Distribution-Unattd	34.00	12.00	
33	Five Points, DE	Distribution-Unattd	69.00	12.47	
34	Felton	Distribution-Unattd	138.00	24.94	
35	Foundry-Cecil, MD	Distribution-Unattd	34.00	4.00	
36	Frankford, DE	Distribution-Unattd	138.00	13.85	
37	Fruitland, MD	Distribution-Unattd	69.00	24.00	
38	Gallion-Harford, MD	Distribution-Unattd	34.00	4.00	
39	Gilpin-Cecil, MD	Distribution-Unattd	34.00	4.00	
40	Glasgow - New Castle, DE	Distribution-Unattd	34.50	12.47	

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	Glasgow - New Castle, DE	Distribution-Unattd	138.00	12.47	
2	Glasgow - New Castle, DE	Distribution-Unattd	138.00	34.50	
3	Glen-Cecil, MD	Distribution-Unattd	34.00	4.16	
4	Gloria St-St. Michaels, MD	Distribution-Unattd	12.47	4.16	
5	Grace Street-St. Michaels, MD	Distribution-Unattd	69.00	7.56	
6	Grasonville, MD	Distribution-Unattd	69.00	26.19	
7	Greenbank, Cecil, MD	Distribution-Unattd	34.00	4.00	
8	Hances-Cecil, MD	Distribution-Unattd	34.00	4.00	
9	Harbeson Sub-Harbeson, DE	Distribution-Unattd	69.00	26.19	
10	Hares Corner - New Castle, DE	Distribution-Unattd	138.00	12.00	
11	Harford-Harford, MD	Distribution-Unattd	34.00	4.16	
12	Harmony -White Clay, DE	Transmission-Unattd	230.00	138.00	
13	Harmony -White Clay, DE	Distribution-Unattd	138.00	34.50	
14	Harmony -White Clay, DE	Distribution-Unattd	138.00	12.47	
15	Harrington -Harrington, DE	Distribution-Unattd	69.00	24.00	
16	Harris-Cecil, MD	Distribution-Unattd	34.00	4.00	
17	Hebron-Hebron, MD	Distribution-Unattd	69.00	25.00	
18	Hillsboro-Hillsboro, MD	Distribution-Unattd	138.00	26.19	
19	Hockessin -Mill Cr Hd, DE	Distribution-Unattd	138.00	12.00	
20	Indian River -Millsboro, DE	Transmission-Unattd	230.00	138.00	
21	Indian River -Millsboro, DE	Transmission-Unattd	138.00	69.00	
22	Irishtown-Cecil, MD	Distribution-Unattd	34.00	4.00	
23	Jacktown-Cambridge, MD	Distribution-Unattd	69.00	13.80	
24	Keeney EHV-Pencader Hd, DE	Transmission-Unattd	500.00	230.00	
25	Keeney EHV-Pencader Hd, DE	Transmission-Unattd	230.00	138.00	
26	Keeney EHV-Pencader Hd, DE	Distribution-Unattd	230.00	34.50	
27	Keeney 138kV, -Pencader Hd, DE	Distribution-Unattd	138.00	12.47	
28	Kenney-Snow Hill, MD	Distribution-Unattd	69.00	24.00	
29	Kent -Dover, DE	Distribution-Unattd	69.00	24.00	
30	Kiamensi -Christiana Rd, DE	Transmission-Unattd	138.00	69.00	
31	Kiamensi -Christiana Rd, DE	Distribution-Unattd	138.00	34.50	
32	Kilby-Cecil, MD	Distribution-Unattd	34.00	4.00	
33	Kings Creek-Princess Anne, MD	Transmission-Unattd	138.00	69.00	
34	Kings Creek-Princess Anne, MD	Distribution-Unattd	138.00	24.94	
35	Laurel -Laurel Sub, DE	Distribution-Unattd	69.00	13.09	
36	Laurel -Laurel Sub, DE	Distribution-Unattd	69.00	13.09	
37	Leslie-Cecil, MD	Distribution-Unattd	34.00	4.00	
38	Liberty Grove-Cecil, MD	Distribution-Unattd	34.00	4.16	
39	Little Falls, DE	Distribution-Unattd	34.00	12.00	
40	Loretto-Princess Anne, MD	Transmission-Unattd	138.00	69.00	

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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	Lums Pond-New Castle Hd, DE	Distribution-Unattd	138.00	25.00	
2	Lynch-Lynch, MD	Distribution-Unattd	69.00	24.94	
3	Macton-Harford, MD	Distribution-Unattd	34.00	4.00	
4	Maridel-Ocean City, MD	Distribution-Unattd	69.00	13.09	
5	Massey -Galena, MD	Distribution-Unattd	69.00	24.94	
6	Mechanics-Cecil, MD	Distribution-Unattd	34.00	4.00	
7	Mermaid -New Castle Hd, DE	Distribution-Unattd	34.50	12.00	
8	Mermaid -New Castle Hd, DE	Distribution-Unattd	138.00	12.00	
9	Middle-Cecil, MD	Distribution-Unattd	34.00	4.00	
10	Midway -Rehoboth, DE	Distribution-Unattd	69.00	13.09	
11	Milford -Milford, DE	Distribution-Unattd	138.00	24.94	
12	Milford -Milford, DE	Transmission-Unattd	230.00	138.00	
13	Milford Crossroads-Mill Cr Rd, DE	Distribution-Unattd	34.00	12.00	
14	Millsboro -Millsboro, DE	Distribution-Unattd	69.00	25.00	
15	Milltown Rd -Mill Cr Rd, DE	Distribution-Unattd	34.50	12.00	
16	Milltown Rd -Mill Cr Rd, DE	Distribution-Unattd	138.00	12.00	
17	Montchanin -Brandywine Hd, DE	Distribution-Unattd	34.00	12.00	
18	Mt. Hermon-Salisbury, MD	Distribution-Unattd	69.00	26.19	
19	Mt. Pleasant-New Castle Hd, DE	Distribution-Unattd	138.00	25.00	
20	Naamans -Brandywine Hd, DE	Distribution-Unattd	69.00	12.00	
21	Nelson -Delmar, DE	Transmission-Unattd	138.00	69.00	
22	Nelson -Delmar, DE	Distribution-Unattd	138.00	24.94	
23	Nesbitt-Cecil, MD	Distribution-Unattd	34.00	4.00	
24	New Castle -New Castle Hd, DE	Distribution-Unattd	69.00	12.00	
25	New Castle -New Castle Hd, DE	Transmission-Unattd	138.00		
26	Normira-Cecil, MD	Distribution-Unattd	34.00	4.00	
27	Northeast-Cecil, MD	Distribution-Unattd	34.00	4.00	
28	N Salisbury, MD	Distribution-Unattd	69.00	26.19	
29	N Seaford Sub-Seaford, DE	Transmission-Unattd	138.00	69.00	
30	N Seaford Sub-Seaford, DE	Distribution-Unattd	69.00	12.47	
31	Oak Hall-Oak Hall, VA	Transmission-Unattd	138.00	69.00	
32	Ocean Bay-Ocean City, MD	Distribution-Unattd	138.00	12.47	
33	Ocean Bay-Ocean City, MD	Transmission-Unattd	138.00	69.00	
34	Ocean City, MD	Distribution-Unattd	69.00	13.09	
35	138th St. Ocean City, MD	Distribution-Unattd	138.00	16.00	
36	138th St. Ocean City, MD	Transmission-Unattd	138.00	16.00	
37	Otsego-Cecil, MD	Distribution-Unattd	34.00	4.00	
38	Pemberton - Salisbury, MD	Distribution-Unattd	69.00	25.00	
39	Perch - Cecil, MD	Distribution-Unattd	34.00	4.00	
40	Piney Grove-Salisbury, MD	Transmission-Unattd	138.00	69.00	

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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	Piney Grove-Salisbury, MD	Transmission-Unattd	230.00	138.00	
2	Pocomoke-Pocomoke, MD	Distribution-Unattd	138.00	13.09	
3	Point Breeze -Brandywine Rd, DE	Distribution-Unattd	34.00	12.00	
4	Porter's Bridge-Cecil, MD	Distribution-Unattd	34.00	4.00	
5	Preston-Preston	Distribution-Unattd	69.00	12.50	
6	Price Sub - Price, MD	Distribution-Unattd	69.00	25.00	
7	Prince-Cecil, MD	Distribution-Unattd	34.00	4.00	
8	Prospect - Street, MD	Distribution - (U)	34.00	4.00	
9	Red Lion-New Castle, DE	Transmission-Unattd	525.00	230.00	
10	Red Lion-New Castle, DE	Distribution-Unattd	138.00	25.00	
11	Red Lion Sub-Pencader Hd, DE	Transmission-Unattd	230.00	138.00	
12	Rehoboth Sub-Rehoboth, DE	Transmission-Unattd	138.00	69.00	
13	Rehoboth Sub-Rehoboth, DE	Distribution-Unattd	69.00	12.50	
14	Reybold Sub-Red Lion Hd, DE	Transmission-Unattd	138.00	69.00	
15	Reybold Sub-Red Lion Hd, DE	Distribution-Unattd	138.00	12.00	
16	Rising Sun-Cecil, MD	Distribution-Unattd	34.00	4.00	
17	Sharptown-Sharptown, MD	Distribution-Unattd	69.00	12.50	
18	Silverbrook Sub, DE	Distribution-Unattd	138.00	34.50	
19	Silverside, DE	Distribution-Unattd	12.00	4.20	
20	Silverside Rd Sub-Brandywine Hd, DE	Distribution-Unattd	69.00	12.00	
21	Silverside Rd Sub-Brandywine Hd, DE	Distribution-Unattd	69.00	34.50	
22	S Harrington Sub-Harrington, DE	Transmission-Unattd	138.00	69.00	
23	Steele-Denton, MD	Transmission-Unattd	230.00	138.00	
24	Steele-Denton, MD	Distribution-Unattd	138.00	25.00	
25	Steele-Denton, MD	Distribution - (U)	69.00	25.00	
26	Stevensville, MD	Distribution-Unattd	69.00	25.00	
27	Stockton-Stockton, MD	Distribution-Unattd	69.00	25.00	
28	Sunset Lake Sub-Pencader Hd, DE	Distribution-Unattd	138.00	12.00	
29	Sussex Sub-Georgetown, DE	Distribution-Unattd	69.00	12.50	
30	Talleyville Sub-Brandywine Hd, DE	Distribution-Unattd	34.50	12.00	
31	Talleyville, DE	Distribution-Unattd	138.00	12.00	
32	Telegraph-Cecil, MD	Distribution-Unattd	34.00	25.00	
33	Theodore-Cecil, MD	Distribution-Unattd	34.00	4.00	
34	Todd-Hurlock, MD	Distribution-Unattd	69.00	25.00	
35	Todd-Hurlock, MD	Distribution-Unattd	69.00	12.00	
36	Todd-Hurlock, MD	Distribution-Unattd	69.00	25.00	
37	Townsend Sub-New Castle Hd, DE	Distribution-Unattd	138.00	25.00	
38	Trappe-Trappe, MD	Distribution-Unattd	69.00	12.50	
39	Triumph-Cecil, MD	Distribution-Unattd	34.00	4.00	
40	Vienna-Vienna, MD	Transmission-Unattd	138.00	69.00	

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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	Vienna-Vienna, MD-Local	Distribution-Unattd	69.00	12.50	
2	Vienna-Vienna, MD	Transmission-Unattd	230.00	138.00	
3	Walnut-Cecil, MD	Distribution-Unattd	34.00	4.00	
4	Washington College - Chestertown, MD	Distribution-Unattd	25.00	4.20	
5	Wattsville-Wattsville, VA	Distribution-Unattd	69.00		
6	Wattsville-Wattsville, VA	Transmission-Unattd	138.00	69.00	
7	West Sub-Christiana Hd, DE	Distribution-Unattd	69.00	34.50	
8	West Sub-Christiana Hd, DE	Distribution-Unattd	69.00	12.00	
9	West Cambridge, MD	Distribution-Unattd	69.00	12.00	
10	West Wilmington-Wilm, DE	Distribution-Unattd	138.00	12.00	
11	Whiteford-Harford, MD	Distribution-Unattd	34.00	4.00	
12	Woodlawn-Cecil, MD	Distribution-Unattd	34.00	4.00	
13	Worcester-Berlin, MD	Distribution-Unattd	69.00	25.00	
14	Worcester-Berlin, MD	Transmission-Unattd	138.00	69.00	
15	Wye Mills, Wye Mills, MD	Transmission-Unattd	138.00	69.00	
16	Wye Mills, Wye Mills, MD	Distribution-Unattd	69.00	25.00	
17	Spare Transformer		34.00	12.00	
18	Spare Transformer		138.00	36.20	
19	Spare Transformer		34.50	4.40	
20	Spare Transformer		138.00	12.47	
21	Spare Transformer		138.00	12.47	
22	Spare Transformer		34.50	4.36	
23	Spare Transformer		138.00	24.94	
24	Spare Transformer		230.00	16.00	
25	Spare Transformer		230.00	34.50	
26	Spare Transformer		138.00	36.20	
27	Spare Transformer		34.00	12.00	
28	Spare Transformer		138.00	12.47	
29	Spare Transformer		138.00	16.00	
30	Spare Transformer		69.00	24.94	
31	Spare Transformer		34.40	4.36	
32	Spare Transformer		69.00	12.47	
33	Spare Transformer		138.00	24.94	
34	Spare Transformer		138.00	12.00	
35	Spare Transformer		138.00	25.00	
36	Spare Transformer		69.00	34.50	
37	Spare Transformer		138.00	69.00	
38	Spare Transformer		230.00	138.00	
39	Spare Transformer		500.00	230.00	
40	Spare Transformer		500.00	230.00	

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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	Spare Transformer		230.00	138.00	
2	Spare Transformer		230.00	138.00	
3	Spare Transformer		230.00	69.00	
4	Spare Transformer		138.00	69.00	
5	Spare Transformer		138.00	25.00	
6	Spare Transformer		69.00	34.00	
7					
8	Mobile D1		138.00	25.00	
9	Mobile D2		69.00	25.00	
10	Mobile D3		34.00	12.00	
11	Mobile D4		138.00	25.00	
12	Mobile D5		69.00	25.00	
13	Mobile D6		138.00	25.00	
14	Mobile D7		69.00	25.00	
15	Mobile D8		69.00	12.00	
16	Mobile D9		138.00	12.00	
17	Mobile D10		138.00	25.00	
18	Mobile D11		138.00	25.00	
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
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					1
6	2					2
84	3					3
22	1					4
22	1		69kV capacitor bank	1	24	5
112	2					6
112	2					7
84	1	1				8
40	1					9
224	1		138kv capacitor bank	1	29	10
20	1		69kV capacitor bank	2	34	11
38	1					12
4	1					13
8	2					14
56	2					15
168	2		12kv capacitor bank	2	14	16
37	4		69kV capacitor bank	2	30	17
45	2					18
4	1					19
68	2		69kv capacitor bank	1	12	20
100	1					21
84	1	1	34kv capacitor bank	2	29	22
75	2					23
8	2					24
8	2					25
112	1					26
90	1					27
336	1					28
8	2	1				29
336	1		230kV reactor	1	40	30
28	2					31
75	2					32
33	4					33
84	1		138kv capacitor bank	2	29	34
84	1		34kv capacitor bank	1	6	35
8	2					36
4	1					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)

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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					1
168	3	1	12kv capacitor bank	6	36	2
325	2					3
63	2					4
112	2	1				5
335	2					6
4	1					7
50	2					8
220	2	1				9
336	1					10
4	1					11
224	2					12
28	1					13
20	1					14
3	3					15
4	1					16
22	1					17
75	2					18
50	1					19
4	1					20
8	2					21
6	1					22
	1					23
168	1					24
	1					25
62	1					26
224	2	1				27
336	1					28
206	3					29
5	1					30
17	3					31
45	2					32
45	2					33
						34
4	1					35
28	1					36
102	2					37
8	2					38
4	1					39
8	1					40

SUBSTATIONS (Continued)

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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					1
84	1					2
8	2					3
3	6					4
32	6					5
50	2					6
4	1					7
4	1					8
63	2					9
93	2					10
8	2					11
896	2					12
134	2					13
112	2					14
50	2					15
4	1					16
56	2					17
53	2	1				18
112	2					19
1344	3	2				20
225	1					21
4	1					22
38	1					23
2000	2	2				24
448	1	2				25
84	1	1				26
67	2					27
25	2					28
47	2					29
112	1					30
218	2	2				31
4	1					32
224	2					33
50	2					34
40	2		69kV capacitor bank	1	20	35
40	2					36
4	1					37
8	2					38
20	1					39
100	2					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)	
83	2					1
28	1					2
8	2					3
45	2					4
28	1		69kv capacitor bank	1	8	5
3	1					6
20	1	1				7
56	2	1				8
4	1					9
60	2					10
50	1					11
336	1					12
45	2					13
66	2					14
						15
112	2					16
45	2					17
84	2					18
79	2					19
75	1					20
100	2	1				21
50	1	1				22
4	3		12kv capacitor bank	2	12	23
123						24
	1					25
4	1					26
4	2					27
83	2					28
187	2					29
38	1	1				30
224	2					31
80	2					32
200	1					33
75	2					34
84	2					35
75	1					36
8	2					37
33	1					38
4	1					39
225	1					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)	
300	1					1
40	2					2
42	2					3
4	1					4
7	1					5
28	1					6
4	1					7
4	1					8
1569	6					9
28	1					10
672	2					11
224	1					12
75	2					13
112	1					14
74	2					15
7	2					16
7	1					17
184	2					18
7	3					19
104	2	1				20
56	1					21
112	1					22
892	3					23
38	1					24
28		1				25
70	2					26
20	2					27
103	3					28
75	2					29
45	2					30
56	1					31
8	1					32
4	1					33
28	1					34
11	3					35
28	1					36
56	1					37
22	1					38
4	1					39
224	2					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)	
3	1					1
448	1					2
4	1					3
2	1					4
						5
225	1					6
112	2					7
112	2					8
22	1					9
168	2					10
4	1					11
4	1					12
66	2					13
224	1					14
448	2					15
56	2					16
22						17
84						18
4						19
56						20
84						21
4						22
28						23
150						24
112						25
84						26
20						27
56						28
150						29
56						30
2						31
56						32
38						33
38						34
56						35
56						36
112						37
336						38
243						39
333						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)	
448						1
336						2
336						3
225						4
56						5
56						6
						7
25		1				8
12		1				9
20		1				10
12		1				11
40		1				12
28		1				13
30		1				14
27		1				15
21		1				16
30		1				17
30		1				18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						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	120,505,027
4				
5	Exelon Business Services Company (EBSC)			
6	Centralized Support Services	EBSC	Various	79,722,604
7				
8	Atlantic City Electric Co (ACE)			
9	Materials	ACE	Various	1,459,230
10	Building Services (use of building space)	ACE	184	2,308
11				
12	Atlantic Southern Properties (ASP)			
13	Building Services (use of building space)	ASP	184	592
14				
15	Constellation Power Source Gen (CPSG)			
16	Mechanical and Electrical Industrial Services	CPSG	Various	74,145
17				
18	Exelon PowerLabs, LLC (EPL)			
19	Calibration and Engineering Services	EPL	807	2,473
20	Non-power Goods or Services Provided for Affiliate			
21	Atlantic City Electric Co (ACE)			
22	Materials	ACE	154 / 163 / 232	1,140,605
23	Field Operations Services	ACE	415	18,110
24	Extra-High Voltage (EHV) Transmission Agreement	ACE	456.1	78,288
25	Building Services (use of building space)	ACE	Various	19,618
26	Regulatory Services	ACE	415	4,829
27				
28	Baltimore Gas & Electric Co. (BGE)			
29	Mutual Assistance	BGE	456	3,381
30	Extra-High Voltage (EHV) Transmission Agreement	BGE	456.1	234,864
31				
32	Commonwealth Edison Company (ComEd)			
33	Mutual Assistance	ComEd	456	10,431
34				
35	Exelon Business Services Company (EBSC)			
36	Building Services (use of building space)	EBSC	Various	500,859
37	Vehicle Services	EBSC	Various	15,408
38				
39				
40				
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	588	20,579
4	Extra-High Voltage (EHV) Transmission Agreement	PECO	571	36,492
5	Information Technology Services	PECO	Various	33,259
6	Mutual Assistance	PECO	874	5,556
7	Materials	PECO	154	3,649
8				
9	Potomac Electric Power Company (Pepco)			
10	Mutual Assistance	Pepco	Various	17,183
11	Shop Department Fabrication Services	Pepco	Various	542,432
12	Construction and Maintenance Services	Pepco	Various	13,299
13	Materials	Pepco	Various	1,090,155
14				
15	Baltimore Gas & Electric Co. (BGE)			
16	Regulatory Services	BGE	928	179,429
17	Information Technology Services	BGE	Various	94,271
18	Materials	BGE	107	1,043
19	Field Operations and Maintenance Services	BGE	Various	584
20	Non-power Goods or Services Provided for Affiliate			
21	Potomac Electric Power Company (PEPCO)			
22	Mutual Assistance	PEPCO	456	46,183
23	Extra-High Voltage (EHV) Transmission Agreement	PEPCO	456.1	234,864
24	Materials	PEPCO	154 / 163 / 232	515,464
25	Building Services (use of building space)	PEPCO	Various	389
26				
27	PECO Energy Company (PECO)			
28	Materials	PECO	154	3,524
29	Mutual Assistance	PECO	456	511,087
30	Extra-High Voltage (EHV) Transmission Agreement	PECO	456.1	287,052
31				
32	PHI Service Company (PHISCO)			
33	Building Services (use of building space)	PHISCO	Various	2,657,504
34	Vehicle Services	PHISCO	Various	811,228
35	Materials	PHISCO	154 / 163	17,057
36				
37	Constellation Solar MC, LLC (CSM)			
38	Fiber Connection Services	CSM	456	341,589
39				
40	Gateway Solar, LLC (GS)			
41	Solar Project Services	GS	456	43,391
42				
1	Non-power Goods or Services Provided by Affiliated			
2	Commonwealth Edison Company (ComEd)			
3	Information Technology Services	ComEd	Various	106,706
4	Materials	ComEd	154	2,869

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
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	\$ 17,963,994
108	1,426,547
163	630,518
182.3	1,045,306
184	1,900,784
254	23,375
416	90,923
419	(194,814)
426.1	194,570
426.3	7
426.4	133,087
426.5	647,382
430	2,109
431	53,884
556	1,804,218
557	887,919
560	1,697,750
561.1	(1,530)
561.2	(3,864)
561.3	(712)
561.5	44,359
566	1,402,646
568	7,191
570	(29,861)

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

571	501,340
572	111
573	(1,098)
580	413,542
581	167,051
582	4
583	3
584	430
586	841,048
587	376,994
588	2,028,683
589	50
590	357,611
592	154,570
593	575,451
594	304
595	31
596	246
597	380,571
598	19,754
813	269,144
859	108
878	610,854
880	53,757
888	3
893	452,515
902	103,292
903	38,177,659
904	150
908	1,374,758
909	117,558
923	41,918,164
924	(6,581)
925	326
928	973,766
930.1	355,219

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

930.2	561,847
935	<u>4</u>
Total	\$ 120,505,027

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	\$ 26,351,544
108	542,328
163	1,214,536
184	413,335
254	(351,425)
416	66,033
417.1	796
426.1	391,700
426.3	66
426.4	99,959
426.5	1,940
560	2,777,309
561.1	9,264
561.2	22,182
561.3	4,078
561.5	2,518
566	1,722,088
568	2,677
569	26
569.2	948
570	167,589
571	833
573	15,016

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

580	83,502
581	166,620
582	508
583	12,292
584	19,888
585	2,043
586	327,285
587	216
588	498,645
589	2,594
590	15,565
592	137,897
593	516,334
594	88,606
595	13,724
596	28,768
597	8,283
598	20,700
807	9,393
813	22,266
840	2,043
841	31,544
843.1	2,030
843.2	154
843.3	1,265
843.4	859
843.5	536
843.6	404
843.7	625
843.9	10,337
850	5,327
851	47,331
856	11,567
857	3,239
859	4,222
860	487

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) 03/27/2020	Year/Period of Report 2019/Q4
Delmarva Power & Light Company			
FOOTNOTE DATA			

861	236
863	8,846
865	3,538
870	39,826
871	9,903
874	164,452
875	11,024
878	51,158
879	1,830
880	1,358,452
881	49
885	4,561
887	22,724
888	18
889	3,571
892	35,506
893	17,674
894	15,352
902	90,980
903	8,530,784
904	1,298
908	276,082
909	262
912	11,411
920	102,400
921	193,191
923	32,341,016
924	503,368
925	2,700
928	1,500
930.1	361,552
930.2	3,027
935	1,874
Total	\$ 79,722,604

Schedule Page: 429 Line No.: 9 Column: c

ACE Materials 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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

FERC	Amount
107	\$ 64,958
108	14,760
154	1,379,239
Various - overhead acct.	<u>273</u>
Total	\$ 1,459,230

Schedule Page: 429 Line No.: 16 Column: c

CPSG Mechanical and Electrical industrial Services provided to DPL:

FERC	Amount
107	\$ 65,511
108	<u>8,634</u>
Total	\$ 74,145

Schedule Page: 429 Line No.: 25 Column: c

DPL Building Services (use of building space) provided to ACE:

FERC	Amount
456	\$ 16,709
495	<u>2,909</u>
Total	<u>\$ 19,618</u>

Schedule Page: 429 Line No.: 36 Column: c

DPL Building Services (use of building space) provided to EBSC:

FERC	Amount
456	\$ 427,985
495	<u>72,874</u>
Total	\$ 500,859

Schedule Page: 429 Line No.: 37 Column: c

DPL Vehicle Services provided to EBSC:

FERC	Amount
456	\$ 13,123
495	2,285

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

Total \$ 15,408

Schedule Page: 429.1 Line No.: 5 Column: c

PECO Information Technology Services provided to DPL:

FERC	Amount
107	\$ 7,972
921	25,287
Total	\$ 33,259

Schedule Page: 429.1 Line No.: 10 Column: c

Pepco Mutual Assistance provided to DPL:

FERC	Amount
107	\$ 11,283
108	1,253
593	4,647
Total	\$ 17,183

Schedule Page: 429.1 Line No.: 11 Column: c

Pepco Shops Department Fabrication Services provided to DPL:

FERC	Amount
107	\$ 523,732
108	18,700
Total	\$ 542,432

Schedule Page: 429.1 Line No.: 12 Column: c

Pepco Construction and Maintenance Services provided to DPL:

FERC	Amount
107	\$ 7,979
108	5,320
Total	\$ 13,299

Schedule Page: 429.1 Line No.: 13 Column: c

Pepco Materials provided to DPL:

FERC Amount

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

107	\$	825,369
108		13,733
154		249,676
593		<u>1,377</u>
Total	\$	1,090,155

Schedule Page: 429.1 Line No.: 17 Column: c

BGE Information Technology Services provided to DPL:

FERC		Amount
107	\$	50,623
921		<u>43,648</u>
Total	\$	94,271

Schedule Page: 429.1 Line No.: 19 Column: c

BGE Field Operations Services provided to DPL:

FERC		Amount
588	\$	550
813		<u>34</u>
Total	\$	584

Schedule Page: 429.1 Line No.: 25 Column: c

DPL Building Services (use of building space) provided to Pepco:

FERC		Amount
456	\$	331
495		<u>58</u>
Total	\$	389

Schedule Page: 429.1 Line No.: 33 Column: c

DPL Building Services (use of building space) provided to PHISCO:

FERC		Amount
456	\$	2,263,396
495		<u>394,108</u>
Total	\$	2,657,504

Schedule Page: 429.1 Line No.: 34 Column: c

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) 03/27/2020	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

DPL Vehicle Services provided to PHISCO:

FERC	Amount
456	\$ 690,923
495	<u>120,305</u>
Total	\$ 811,228

Schedule Page: 429.2 Line No.: 3 Column: c

ComEd Information Technology Services provided to DPL:

FERC	Amount
107	\$ 88,172
921	<u>18,534</u>
Total	\$ 106,706

Schedule Page: 429.2 Line No.: 7 Column: c

AE Inspection Services provided to DPL:

FERC	Amount
583	\$ 20,706
921	<u>8,175</u>
Total	\$ 28,881

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ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	276,234,797	290,683,123
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	109,566,340	108,682,399
5	Large (or Ind.) (See Instr. 4)	9,221,225	10,007,781
6	(444) Public Street and Highway Lighting	4,297,297	4,276,799
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	399,319,659	413,650,102
11	(447) Sales for Resale	3,238	
12	TOTAL Sales of Electricity	399,322,897	413,650,102
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	399,322,897	413,650,102
15	Other Operating Revenues		
16	(450) Forfeited Discounts	725,895	1,197,564
17	(451) Miscellaneous Service Revenues	227,896	194,905
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	1,514,770	1,780,392
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	7,327,220	7,887,059
22	(456.1) Revenues from Transmission of Electricity of Others	639,597	605,907
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	10,435,378	11,665,827
27	TOTAL Electric Operating Revenues	409,758,275	425,315,929

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
2,137,594	2,219,317	179,408	178,170	2
				3
1,658,493	1,675,311	26,867	26,845	4
369,282	374,418	513	184	5
11,560	11,747	266	268	6
				7
				8
				9
4,176,929	4,280,793	207,054	205,467	10
66				11
4,176,995	4,280,793	207,054	205,467	12
				13
4,176,995	4,280,793	207,054	205,467	14

Line 12, column (b) includes \$ -2,269,211 of unbilled revenues.
 Line 12, column (d) includes -9,789 MWH relating to unbilled revenues

Name of Respondent Delmarva Power & Light Company - Maryland	This Report is: (1) <u> </u> An Original (2) <u> </u> A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2019/Q4
FOOTNOTE DATA			

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

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

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

Amounts over \$250,000:

\$ 6,058,294	RPM Auction
(4,333,343)	MD Billed Stabilization
2,522,773	MD Calendar Revenue Normalization
(1,763,501)	MD Intercompany Revenue

DELMARVA POWER & LIGHT COMPANY
MARYLAND PROPERTY TAXES PAID
12/31/2019

<u>Location</u>	<u>2019 Taxes Paid</u>
Caroline County	844,627
Cecil County	3,498,522
City of Cambridge	170,891
City of Crisfield	42,087
City of Fruitland	89,434
City of Salisbury	35,784
Delmar	10,910
Dorchester County	2,538,764
Eldorado	159
Galena	2,269
Harford County	430,263
Hebron	6,205
Hillsboro	-
Hurlock	20,398
Kent County	1,418
Mardela Springs	2,856
Pocomoke City	110,772
Preston	3,366
Queen Anne's County	1,479,806
Ridgely	12,984
Secretary	2,421
Sharptown	7,841
Snow Hill	37,239
Somerset County	726,452
St. Michaels	30,775
Sudlersville	-
Talbot County	555,512
Town of Betterton	2,697
Town of Brookview	-
Town of Cecilton	2,260
Town of Centreville	161,968
Town of Charlestown	6,257
Town of Chesapeake City	8,903
Town of Chestertown	34,642
Town of Church Creek	-
Town of Church Hill	7,695
Town of Denton	44,050
Town of Elkton	-
Town of Federalsburg	25,634
Town of Goldsboro	943
Town of Greensboro	10,030
Town of Henderson	-
Town of Marydel	2,149
Town of Millington	1,843
Town of North East	46,133
Town of Ocean City	574,451
Town of Perryville	15,178
Town of Pittsville	8,490
Town of Port Deposit	13,114
Town of Princess Anne	-
Town of Queenstown	1,288
Town of Rising Sun	-
Town of Templeville	-
Town of Trappe	4,632
Town of Vienna	5,129
Town of Willards	10,445
Wicomico County	2,404,803
Worcester County	1,881,209
MD Other Property	300
Total	15,935,998

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, 2020
 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.

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

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

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

The number of shares outstanding of each registrant's common stock as of March 31, 2020 was:

Exelon Corporation Common Stock, without par value	974,407,848
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, \$12.50 par value	127,021,353
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	not applicable
Potomac Electric Power Company Common Stock, \$0.01 par value	100
Delmarva Power & Light Company Common Stock, \$2.25 par value	1,000
Atlantic City Electric Company Common Stock, \$3.00 par value	8,546,017

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

<i>Exelon</i>	Exelon Corporation
<i>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 (formerly Pepco Holdings, Inc.)
<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 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>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 2019 Form 10-K</i>	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2019 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>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>	Department of Energy & Environment
<i>DOJ</i>	United States Department of Justice
<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>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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

<i>ISO</i>	Independent System Operator
<i>ISO-NE</i>	Independent System Operator New England Inc.
<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>MW</i>	Megawatt
<i>MWh</i>	Megawatt hour
<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 Agreements 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>REC</i>	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
<i>RNF</i>	Revenues Net of Purchased Power and Fuel Expense
<i>Regulatory Agreement Units</i>	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

<i>RFP</i>	Request for Proposal
<i>Rider</i>	Reconcilable Surcharge Recovery Mechanism
<i>RMC</i>	Risk Management Committee
<i>ROE</i>	Return on equity
<i>ROU</i>	Right-of-use
<i>RTO</i>	Regional Transmission Organization
<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>TCJA</i>	Tax Cuts and Jobs Act
<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 expected or potential impact of the novel coronavirus (COVID-19) pandemic, and the related responses of various governments and regulatory bodies, our customers, and the company, on our business, financial condition and results of operations; any such forward-looking statements, whether concerning the COVID-19 pandemic or otherwise, involve risks, assumptions and uncertainties. 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 2019 Annual Report on Form 10-K in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 18, Commitments and Contingencies; (2) 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, whether written or oral, 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,	
	2020	2019
Operating revenues		
Competitive businesses revenues	\$ 4,403	\$ 4,979
Rate-regulated utility revenues	4,276	4,503
Revenues from alternative revenue programs	67	(5)
Operating revenue from affiliates	1	—
Total operating revenues	<u>8,747</u>	<u>9,477</u>
Operating expenses		
Competitive businesses purchased power and fuel	2,710	3,204
Rate-regulated utility purchased power and fuel	1,157	1,349
Operating and maintenance	2,204	2,189
Depreciation and amortization	1,021	1,075
Taxes other than income taxes	437	445
Total operating expenses	<u>7,529</u>	<u>8,262</u>
Gain on sales of assets and businesses	<u>2</u>	<u>3</u>
Operating income	<u>1,220</u>	<u>1,218</u>
Other income and (deductions)		
Interest expense, net	(404)	(397)
Interest expense to affiliates	(6)	(6)
Other, net	(725)	467
Total other income and (deductions)	<u>(1,135)</u>	<u>64</u>
Income before income taxes	<u>85</u>	<u>1,282</u>
Income taxes	<u>(294)</u>	<u>310</u>
Equity in losses of unconsolidated affiliates	<u>(3)</u>	<u>(6)</u>
Net income	<u>376</u>	<u>966</u>
Net (loss) income attributable to noncontrolling interests	<u>(206)</u>	<u>59</u>
Net income attributable to common shareholders	<u>\$ 582</u>	<u>\$ 907</u>
Comprehensive income, net of income taxes		
Net income	\$ 376	\$ 966
Other comprehensive income (loss), net of income taxes		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	(10)	(16)
Actuarial loss reclassified to periodic benefit cost	47	36
Pension and non-pension postretirement benefit plan valuation adjustment	(7)	(38)
Unrealized loss on cash flow hedges	(1)	—
Unrealized loss on investments in unconsolidated affiliates	—	(2)
Unrealized (loss) gain on foreign currency translation	(8)	2
Other comprehensive income	<u>21</u>	<u>(18)</u>
Comprehensive income	<u>397</u>	<u>948</u>
Comprehensive (loss) income attributable to noncontrolling interests	<u>(206)</u>	<u>58</u>
Comprehensive income attributable to common shareholders	<u>\$ 603</u>	<u>\$ 890</u>
Average shares of common stock outstanding:		
Basic	975	971
Assumed exercise and/or distributions of stock-based awards	1	1
Diluted ^(a)	<u>976</u>	<u>972</u>
Earnings per average common share:		
Basic	\$ 0.60	\$ 0.93
Diluted	\$ 0.60	\$ 0.93

(a) The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was immaterial for the three months ended March 31, 2020 and March 31, 2019.

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,	
	2020	2019
Cash flows from operating activities		
Net income	\$ 376	\$ 966
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	1,378	1,460
Asset impairments	8	7
Deferred income taxes and amortization of investment tax credits	(245)	187
Net fair value changes related to derivatives	(132)	31
Net realized and unrealized losses (gains) on NDT funds	651	(308)
Other non-cash operating activities	273	127
Changes in assets and liabilities:		
Accounts receivable	800	79
Inventories	81	128
Accounts payable and accrued expenses	(976)	(764)
Option premiums (paid) received, net	(38)	6
Collateral posted, net	(21)	(101)
Income taxes	(56)	141
Pension and non-pension postretirement benefit contributions	(531)	(328)
Other assets and liabilities	(488)	(587)
Net cash flows provided by operating activities	<u>1,080</u>	<u>1,044</u>
Cash flows from investing activities		
Capital expenditures	(2,016)	(1,873)
Proceeds from NDT fund sales	1,183	3,713
Investment in NDT funds	(1,234)	(3,666)
Proceeds from sales of assets and businesses	—	8
Other investing activities	(8)	32
Net cash flows used in investing activities	<u>(2,075)</u>	<u>(1,786)</u>
Cash flows from financing activities		
Changes in short-term borrowings	109	540
Proceeds from short-term borrowings with maturities greater than 90 days	500	—
Issuance of long-term debt	2,652	402
Retirement of long-term debt	(1,032)	(352)
Dividends paid on common stock	(373)	(352)
Proceeds from employee stock plans	30	51
Other financing activities	(21)	(14)
Net cash flows provided by financing activities	<u>1,865</u>	<u>275</u>
Increase (decrease) in cash, cash equivalents and restricted cash	<u>870</u>	<u>(467)</u>
Cash, cash equivalents and restricted cash at beginning of period	<u>1,122</u>	<u>1,781</u>
Cash, cash equivalents and restricted cash at end of period	<u>\$ 1,992</u>	<u>\$ 1,314</u>
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (180)	\$ (229)
Increase in PPE related to ARO update	—	301

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	\$ 1,457	\$ 587
Restricted cash and cash equivalents	414	358
Accounts receivable		
Customer accounts receivable	4,320	4,835
Customer allowance for credit losses	(278)	(243)
Customer accounts receivable, net	4,042	4,592
Other accounts receivable	1,391	1,631
Other allowance for credit losses	(52)	(48)
Other accounts receivable, net	1,339	1,583
Mark-to-market derivative assets	656	679
Unamortized energy contract assets	47	47
Inventories, net		
Fossil fuel and emission allowances	224	312
Materials and supplies	1,463	1,456
Regulatory assets	1,205	1,170
Other	1,629	1,253
Total current assets	12,476	12,037
Property, plant and equipment (net of accumulated depreciation and amortization of \$24,449 and \$23,979 as of March 31, 2020 and December 31, 2019, respectively)	81,017	80,233
Deferred debits and other assets		
Regulatory assets	8,360	8,335
Nuclear decommissioning trust funds	11,611	13,190
Investments	418	464
Goodwill	6,677	6,677
Mark-to-market derivative assets	625	508
Unamortized energy contract assets	329	336
Other	3,164	3,197
Total deferred debits and other assets	31,184	32,707
Total assets^(a)	\$ 124,677	\$ 124,977

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	\$ 1,979	\$ 1,370
Long-term debt due within one year	2,848	4,710
Accounts payable	2,883	3,560
Accrued expenses	1,535	1,981
Payables to affiliates	5	5
Regulatory liabilities	412	406
Mark-to-market derivative liabilities	264	247
Unamortized energy contract liabilities	121	132
Renewable energy credit obligation	451	443
Other	1,276	1,331
Total current liabilities	11,774	14,185
Long-term debt	34,808	31,329
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	12,242	12,351
Asset retirement obligations	10,951	10,846
Pension obligations	3,705	4,247
Non-pension postretirement benefit obligations	2,112	2,076
Spent nuclear fuel obligation	1,204	1,199
Regulatory liabilities	9,105	9,986
Mark-to-market derivative liabilities	436	393
Unamortized energy contract liabilities	317	338
Other	3,017	3,064
Total deferred credits and other liabilities	43,089	44,500
Total liabilities ^(a)	90,061	90,404
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 974 shares and 973 shares outstanding at March 31, 2020 and December 31, 2019, respectively)	19,303	19,274
Treasury stock, at cost (2 shares at March 31, 2020 and December 31, 2019)	(123)	(123)
Retained earnings	16,475	16,267
Accumulated other comprehensive loss, net	(3,173)	(3,194)
Total shareholders' equity	32,482	32,224
Noncontrolling interests	2,134	2,349
Total equity	34,616	34,573
Total liabilities and shareholders' equity	\$ 124,677	\$ 124,977

(a) Exelon's consolidated assets include \$9,056 million and \$9,532 million at March 31, 2020 and December 31, 2019, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include \$3,412 million and \$3,473 million at March 31, 2020 and December 31, 2019, 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)

<u>(In millions, shares in thousands)</u>	Three Months Ended March 31, 2020						
	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	—	—	—	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	976,240	\$ 19,303	\$ (123)	\$ 16,475	\$ (3,173)	\$ 2,134	\$ 34,616

<u>(In millions, shares in thousands)</u>	Three Months Ended March 31, 2019						
	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2018	970,020	\$ 19,116	\$ (123)	\$ 14,766	\$ (2,995)	\$ 2,306	\$ 33,070
Net income	—	—	—	907	—	59	966
Long-term incentive plan activity	2,446	(3)	—	—	—	—	(3)
Employee stock purchase plan issuances	320	51	—	—	—	—	51
Changes in equity of noncontrolling interests	—	—	—	—	—	(17)	(17)
Sale of noncontrolling interests	—	7	—	—	—	—	7
Common stock dividends (\$0.36/common share)	—	—	—	(352)	—	—	(352)
Other comprehensive loss, net of income taxes	—	—	—	—	(17)	(1)	(18)
Balance, March 31, 2019	972,786	\$ 19,171	\$ (123)	\$ 15,321	\$ (3,012)	\$ 2,347	\$ 33,704

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,	
	2020	2019
Operating revenues		
Operating revenues	\$ 4,403	\$ 4,979
Operating revenues from affiliates	330	317
Total operating revenues	<u>4,733</u>	<u>5,296</u>
Operating expenses		
Purchased power and fuel	2,710	3,204
Purchased power and fuel from affiliates	(6)	1
Operating and maintenance	1,121	1,068
Operating and maintenance from affiliates	142	150
Depreciation and amortization	304	405
Taxes other than income taxes	129	135
Total operating expenses	<u>4,400</u>	<u>4,963</u>
Operating income	<u>333</u>	<u>333</u>
Other income and (deductions)		
Interest expense, net	(100)	(102)
Interest expense to affiliates	(9)	(9)
Other, net	(771)	430
Total other income and (deductions)	<u>(880)</u>	<u>319</u>
(Loss) income before income taxes	<u>(547)</u>	<u>652</u>
Income taxes	(389)	224
Equity in losses of unconsolidated affiliates	<u>(3)</u>	<u>(6)</u>
Net (loss) income	<u>(161)</u>	<u>422</u>
Net (loss) income attributable to noncontrolling interests	<u>(206)</u>	<u>59</u>
Net income attributable to membership interest	<u>\$ 45</u>	<u>\$ 363</u>
Comprehensive income, net of income taxes		
Net (loss) income	\$ (161)	\$ 422
Other comprehensive (loss) income, net of income taxes		
Unrealized (loss) gain on cash flow hedges	(1)	1
Unrealized loss on investments in unconsolidated affiliates	—	(2)
Unrealized (loss) gain on foreign currency translation	(8)	2
Other comprehensive (loss) income	<u>(9)</u>	<u>1</u>
Comprehensive (loss) income	<u>(170)</u>	<u>423</u>
Comprehensive (loss) income attributable to noncontrolling interests	<u>(206)</u>	<u>58</u>
Comprehensive income attributable to membership interest	<u>\$ 36</u>	<u>\$ 365</u>

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

<u>(In millions)</u>	Three Months Ended March 31,	
	2020	2019
Cash flows from operating activities		
Net (loss) income	\$ (161)	\$ 422
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	661	789
Asset impairments	8	7
Deferred income taxes and amortization of investment tax credits	(329)	108
Net fair value changes related to derivatives	(127)	33
Net realized and unrealized losses (gains) on NDT funds	651	(308)
Other non-cash operating activities	205	(90)
Changes in assets and liabilities:		
Accounts receivable	787	197
Receivables from and payables to affiliates, net	34	(5)
Inventories	39	103
Accounts payable and accrued expenses	(614)	(411)
Option premiums (paid) received, net	(38)	6
Collateral posted, net	(22)	(87)
Income taxes	(58)	146
Pension and non-pension postretirement benefit contributions	(232)	(141)
Other assets and liabilities	(184)	(187)
Net cash flows provided by operating activities	620	582
Cash flows from investing activities		
Capital expenditures	(558)	(511)
Proceeds from NDT fund sales	1,183	3,713
Investment in NDT funds	(1,234)	(3,666)
Proceeds from sales of assets and businesses	—	8
Changes in Exelon intercompany money pool	(254)	—
Other investing activities	(8)	23
Net cash flows used in investing activities	(871)	(433)
Cash flows from financing activities		
Changes in short-term borrowings	275	—
Proceeds from short-term borrowings with maturities greater than 90 days	500	—
Issuance of long-term debt	1,502	2
Retirement of long-term debt	(1,028)	(47)
Changes in Exelon intercompany money pool	—	(100)
Distributions to member	(468)	(225)
Other financing activities	(8)	(6)
Net cash flows provided by (used in) financing activities	773	(376)
Increase (decrease) in cash, cash equivalents and restricted cash	522	(227)
Cash, cash equivalents and restricted cash at beginning of period	449	903
Cash, cash equivalents and restricted cash at end of period	\$ 971	\$ 676
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (56)	\$ (93)
Increase in PPE related to ARO update	—	301

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, 2020</u>	<u>December 31, 2019</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 821	\$ 303
Restricted cash and cash equivalents	150	146
Accounts receivable		
Customer accounts receivable	2,496	2,973
Customer allowance for credit losses	(81)	(80)
Customer accounts receivable, net	2,415	2,893
Other accounts receivable	353	619
Other accounts receivable, net	353	619
Mark-to-market derivative assets	650	675
Receivables from affiliates	167	190
Receivable from Exelon intercompany money pool	254	—
Unamortized energy contract assets	47	47
Inventories, net		
Fossil fuel and emission allowances	186	236
Materials and supplies	1,038	1,026
Other	1,243	941
Total current assets	7,324	7,076
Property, plant and equipment (net of accumulated depreciation and amortization of \$12,114 and \$12,017 as of March 31, 2020 and December 31, 2019, respectively)	24,169	24,193
Deferred debits and other assets		
Nuclear decommissioning trust funds	11,611	13,190
Investments	189	235
Goodwill	47	47
Mark-to-market derivative assets	625	508
Prepaid pension asset	1,638	1,438
Unamortized energy contract assets	328	336
Deferred income taxes	10	12
Other	1,941	1,960
Total deferred debits and other assets	16,389	17,726
Total assets^(a)	\$ 47,882	\$ 48,995

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, 2020</u>	<u>December 31, 2019</u>
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	\$ 1,095	\$ 320
Long-term debt due within one year	1,623	2,624
Long-term debt to affiliates due within one year	556	558
Accounts payable	1,195	1,692
Accrued expenses	603	786
Payables to affiliates	128	117
Mark-to-market derivative liabilities	229	215
Unamortized energy contract liabilities	12	17
Renewable energy credit obligation	450	443
Other	434	517
Total current liabilities	6,325	7,289
Long-term debt	5,943	4,464
Long-term debt to affiliates	327	328
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,424	3,752
Asset retirement obligations	10,709	10,603
Non-pension postretirement benefit obligations	873	878
Spent nuclear fuel obligation	1,204	1,199
Payables to affiliates	2,302	3,103
Mark-to-market derivative liabilities	158	123
Unamortized energy contract liabilities	10	11
Other	1,424	1,415
Total deferred credits and other liabilities	20,104	21,084
Total liabilities ^(a)	32,699	33,165
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,568	9,566
Undistributed earnings	3,527	3,950
Accumulated other comprehensive loss, net	(41)	(32)
Total member's equity	13,054	13,484
Noncontrolling interests	2,129	2,346
Total equity	15,183	15,830
Total liabilities and equity	\$ 47,882	\$ 48,995

(a) Generation's consolidated assets include \$9,034 million and \$9,512 million at March 31, 2020 and December 31, 2019, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include \$3,369 million and \$3,429 million at March 31, 2020 and December 31, 2019, 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, 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

Three Months Ended March 31, 2019					
(In millions)	Member's Equity				Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	
Balance, December 31, 2018	\$ 9,518	\$ 3,724	\$ (38)	\$ 2,304	\$ 15,508
Net income	—	363	—	59	422
Changes in equity of noncontrolling interests	—	—	—	(17)	(17)
Sale of noncontrolling interests	7	—	—	—	7
Distributions to member	—	(225)	—	—	(225)
Other comprehensive income, net of income taxes	—	—	2	(1)	1
Balance, March 31, 2019	\$ 9,525	\$ 3,862	\$ (36)	\$ 2,345	\$ 15,696

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,	
	2020	2019
Operating revenues		
Electric operating revenues	\$ 1,422	\$ 1,432
Revenues from alternative revenue programs	12	(28)
Operating revenues from affiliates	5	4
Total operating revenues	1,439	1,408
Operating expenses		
Purchased power	389	388
Purchased power from affiliate	97	97
Operating and maintenance	243	259
Operating and maintenance from affiliate	74	62
Depreciation and amortization	273	251
Taxes other than income taxes	75	78
Total operating expenses	1,151	1,135
Gain on sales of assets	—	3
Operating income	288	276
Other income and (deductions)		
Interest expense, net	(91)	(84)
Interest expense to affiliates	(3)	(3)
Other, net	10	8
Total other income and (deductions)	(84)	(79)
Income before income taxes	204	197
Income taxes	36	40
Net income	\$ 168	\$ 157
Comprehensive income	\$ 168	\$ 157

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

(In millions)	Three Months Ended March 31,	
	2020	2019
Cash flows from operating activities		
Net income	\$ 168	\$ 157
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	273	251
Deferred income taxes and amortization of investment tax credits	42	34
Other non-cash operating activities	16	56
Changes in assets and liabilities:		
Accounts receivable	9	14
Receivables from and payables to affiliates, net	(6)	(34)
Inventories	(2)	(3)
Accounts payable and accrued expenses	(147)	(188)
Counterparty collateral received (posted), net and cash deposits	3	(13)
Income taxes	(7)	5
Pension and non-pension postretirement benefit contributions	(143)	(67)
Other assets and liabilities	(132)	(121)
Net cash flows provided by operating activities	74	91
Cash flows from investing activities		
Capital expenditures	(506)	(503)
Other investing activities	5	11
Net cash flows used in investing activities	(501)	(492)
Cash flows from financing activities		
Changes in short-term borrowings	(130)	322
Issuance of long-term debt	1,000	400
Retirement of long-term debt	—	(300)
Dividends paid on common stock	(125)	(127)
Contributions from parent	125	63
Other financing activities	(13)	(9)
Net cash flows provided by financing activities	857	349
Increase (decrease) in cash, cash equivalents and restricted cash	430	(52)
Cash, cash equivalents and restricted cash at beginning of period	403	330
Cash, cash equivalents and restricted cash at end of period	\$ 833	\$ 278
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (5)	\$ (80)

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 514	\$ 90
Restricted cash and cash equivalents	211	150
Accounts receivable		
Customer accounts receivable	600	604
Customer allowance for credit losses	(71)	(59)
Customer accounts receivable, net	529	545
Other accounts receivable	307	306
Other allowance for credit losses	(22)	(20)
Other accounts receivable, net	285	286
Receivables from affiliates	18	28
Inventories, net	161	159
Regulatory assets	290	281
Other	51	44
Total current assets	2,059	1,583
Property, plant and equipment (net of accumulated depreciation and amortization of \$5,315 and \$5,168 as of March 31, 2020 and December 31, 2019, respectively)	23,390	23,107
Deferred debits and other assets		
Regulatory assets	1,567	1,480
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,040	2,622
Prepaid pension asset	1,108	995
Other	351	347
Total deferred debits and other assets	7,697	8,075
Total assets	\$ 33,146	\$ 32,765

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	\$ —	\$ 130
Long-term debt due within one year	500	500
Accounts payable	503	527
Accrued expenses	258	385
Payables to affiliates	87	103
Customer deposits	118	118
Regulatory liabilities	186	200
Mark-to-market derivative liability	36	32
Other	117	122
Total current liabilities	1,805	2,117
Long-term debt	8,978	7,991
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,094	4,021
Asset retirement obligations	128	128
Non-pension postretirement benefits obligations	178	180
Regulatory liabilities	5,960	6,542
Mark-to-market derivative liability	278	269
Other	675	635
Total deferred credits and other liabilities	11,313	11,775
Total liabilities	22,301	22,088
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	7,697	7,572
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	3,199	3,156
Total shareholders' equity	10,845	10,677
Total liabilities and shareholders' equity	\$ 33,146	\$ 32,765

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, 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	\$ 1,588	\$ 7,697	\$ (1,639)	\$ 3,199	\$ 10,845
Three Months Ended March 31, 2019					
(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2018	\$ 1,588	\$ 7,322	\$ (1,639)	\$ 2,976	\$ 10,247
Net income	—	—	157	—	157
Appropriation of retained earnings for future dividends	—	—	(157)	157	—
Common stock dividends	—	—	—	(127)	(127)
Contributions from parent	—	63	—	—	63
Balance, March 31, 2019	\$ 1,588	\$ 7,385	\$ (1,639)	\$ 3,006	\$ 10,340

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	Three Months Ended March 31,	
	2020	2019
Operating revenues		
Electric operating revenues	\$ 600	\$ 622
Natural gas operating revenues	209	280
Revenues from alternative revenue programs	2	(3)
Operating revenues from affiliates	2	1
Total operating revenues	813	900
Operating expenses		
Purchased power	164	152
Purchased fuel	83	135
Purchased power from affiliate	36	44
Operating and maintenance	179	187
Operating and maintenance from affiliates	38	38
Depreciation and amortization	86	81
Taxes other than income taxes	39	41
Total operating expenses	625	678
Operating income	188	222
Other income and (deductions)		
Interest expense, net	(33)	(30)
Interest expense to affiliates	(3)	(3)
Other, net	3	4
Total other income and (deductions)	(33)	(29)
Income before income taxes	155	193
Income taxes	15	25
Net income	\$ 140	\$ 168
Comprehensive income	\$ 140	\$ 168

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,	
	2020	2019
Cash flows from operating activities		
Net income	\$ 140	\$ 168
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	86	81
Deferred income taxes and amortization of investment tax credits	2	5
Other non-cash operating activities	22	16
Changes in assets and liabilities:		
Accounts receivable	14	(86)
Receivables from and payables to affiliates, net	(3)	7
Inventories	15	23
Accounts payable and accrued expenses	(45)	(13)
Income taxes	14	20
Pension and non-pension postretirement benefit contributions	(16)	(25)
Other assets and liabilities	(84)	(119)
Net cash flows provided by operating activities	145	77
Cash flows from investing activities		
Capital expenditures	(259)	(222)
Changes in Exelon intercompany money pool	(22)	—
Other investing activities	1	2
Net cash flows used in investing activities	(280)	(220)
Cash flows from financing activities		
Dividends paid on common stock	(85)	(90)
Contributions from parent	231	145
Net cash flows provided by financing activities	146	55
Increase (decrease) in cash, cash equivalents and restricted cash	11	(88)
Cash, cash equivalents and restricted cash at beginning of period	27	135
Cash, cash equivalents and restricted cash at end of period	\$ 38	\$ 47
Supplemental cash flow information		
(Decrease) Increase in capital expenditures not paid	\$ (11)	\$ 8

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 31	\$ 21
Restricted cash and cash equivalents	7	6
Accounts receivable		
Customer accounts receivable	394	412
Customer allowance for credit losses	(66)	(55)
Customer accounts receivable, net	328	357
Other accounts receivable	128	145
Other allowance for credit losses	(7)	(7)
Other accounts receivable, net	121	138
Receivable from affiliates	—	1
Receivable from Exelon intercompany pool	90	68
Inventories, net		
Fossil fuel	21	36
Materials and supplies	35	35
Prepaid utility taxes	101	—
Regulatory assets	35	41
Other	20	19
Total current assets	789	722
Property, plant and equipment (net of accumulated depreciation and amortization of \$3,753 and \$3,718 as of March 31, 2020 and December 31, 2019, respectively)	9,462	9,292
Deferred debits and other assets		
Regulatory assets	588	554
Investments	25	27
Receivable from affiliates	261	480
Prepaid pension asset	380	365
Other	30	29
Total deferred debits and other assets	1,284	1,455
Total assets	\$ 11,535	\$ 11,469

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable	\$ 357	\$ 387
Accrued expenses	76	101
Payables to affiliates	51	55
Customer deposits	70	69
Regulatory liabilities	104	91
Other	27	19
Total current liabilities	685	722
Long-term debt	3,406	3,405
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,119	2,080
Asset retirement obligations	26	28
Non-pension postretirement benefits obligations	288	288
Regulatory liabilities	290	510
Other	73	74
Total deferred credits and other liabilities	2,796	2,980
Total liabilities	7,071	7,291
Commitments and contingencies		
Shareholder's equity		
Common stock	2,997	2,766
Retained earnings	1,467	1,412
Total shareholder's equity	4,464	4,178
Total liabilities and shareholder's equity	\$ 11,535	\$ 11,469

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	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

<u>(In millions)</u>	Three months ended March 31, 2019		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	\$ 2,578	\$ 1,242	\$ 3,820
Net income	—	168	168
Common stock dividends	—	(90)	(90)
Contributions from parent	145	—	145
Balance, March 31, 2019	\$ 2,723	\$ 1,320	\$ 4,043

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,	
	2020	2019
Operating revenues		
Electric operating revenues	\$ 595	\$ 652
Natural gas operating revenues	300	308
Revenues from alternative revenue programs	36	10
Operating revenues from affiliates	6	6
Total operating revenues	937	976
Operating expenses		
Purchased power	114	190
Purchased fuel	76	95
Purchased power from affiliate	98	75
Operating and maintenance	146	153
Operating and maintenance from affiliates	42	39
Depreciation and amortization	143	136
Taxes other than income taxes	69	68
Total operating expenses	688	756
Operating income	249	220
Other income and (deductions)		
Interest expense, net	(32)	(29)
Other, net	5	5
Total other income and (deductions)	(27)	(24)
Income before income taxes	222	196
Income taxes	41	36
Net income	\$ 181	\$ 160
Comprehensive income	\$ 181	\$ 160

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,	
	2020	2019
Cash flows from operating activities		
Net income	\$ 181	\$ 160
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	143	136
Deferred income taxes and amortization of investment tax credits	33	28
Other non-cash operating activities	(8)	27
Changes in assets and liabilities:		
Accounts receivable	(28)	(39)
Receivables from and payables to affiliates, net	(13)	(10)
Inventories	20	17
Accounts payable and accrued expenses	(9)	(27)
Collateral posted, net	—	(1)
Income taxes	7	8
Pension and non-pension postretirement benefit contributions	(64)	(40)
Other assets and liabilities	10	(14)
Net cash flows provided by operating activities	272	245
Cash flows from investing activities		
Capital expenditures	(283)	(258)
Other investing activities	(6)	1
Net cash flows used in investing activities	(289)	(257)
Cash flows from financing activities		
Changes in short-term borrowings	66	71
Dividends paid on common stock	(62)	(56)
Net cash flows provided by financing activities	4	15
(Decrease) Increase in cash, cash equivalents and restricted cash	(13)	3
Cash, cash equivalents and restricted cash at beginning of period	25	13
Cash, cash equivalents and restricted cash at end of period	\$ 12	\$ 16
Supplemental cash flow information		
(Decrease) Increase in capital expenditures not paid	\$ (35)	\$ 2

See the Combined Notes to Consolidated Financial Statements

**BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 11	\$ 24
Restricted cash and cash equivalents	1	1
Accounts receivable		
Customer accounts receivable	358	329
Customer allowance for credit losses	(18)	(12)
Customer accounts receivable, net	340	317
Other accounts receivable	143	152
Other allowance for credit losses	(5)	(5)
Other accounts receivable, net	138	147
Receivables from affiliates	1	1
Inventories, net		
Fossil fuel	13	30
Materials and supplies	43	46
Prepaid utility taxes	40	78
Regulatory assets	201	183
Other	5	6
Total current assets	793	833
Property, plant and equipment (net of accumulated depreciation and amortization of \$3,898 and \$3,834 as of March 31, 2020 and December 31, 2019, respectively)	9,147	8,990
Deferred debits and other assets		
Regulatory assets	453	454
Investments	7	7
Prepaid pension asset	308	264
Other	81	86
Total deferred debits and other assets	849	811
Total assets	\$ 10,789	\$ 10,634

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ 141	\$ 76
Accounts payable	224	243
Accrued expenses	127	152
Payables to affiliates	52	66
Customer deposits	119	120
Regulatory liabilities	39	33
Other	78	63
Total current liabilities	780	753
Long-term debt	3,271	3,270
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,457	1,396
Asset retirement obligations	22	22
Non-pension postretirement benefits obligations	194	199
Regulatory liabilities	1,163	1,195
Other	100	116
Total deferred credits and other liabilities	2,936	2,928
Total liabilities	6,987	6,951
Commitments and contingencies		
Shareholder's equity		
Common stock	1,907	1,907
Retained earnings	1,895	1,776
Total shareholder's equity	3,802	3,683
Total liabilities and shareholder's equity	\$ 10,789	\$ 10,634

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

<i>(In millions)</i>	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

<i>(In millions)</i>	Three Months Ended March 31, 2019		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	\$ 1,714	\$ 1,640	\$ 3,354
Net income	—	160	160
Common stock dividends	—	(56)	(56)
Balance, March 31, 2019	\$ 1,714	\$ 1,744	\$ 3,458

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	Three Months Ended March 31,	
	2020	2019
Operating revenues		
Electric operating revenues	\$ 1,086	\$ 1,139
Natural gas operating revenues	64	71
Revenues from alternative revenue programs	18	15
Operating revenues from affiliates	3	3
Total operating revenues	1,171	1,228
Operating expenses		
Purchased power	300	355
Purchased fuel	31	34
Purchased power and fuel from affiliates	104	101
Operating and maintenance	219	239
Operating and maintenance from affiliates	38	33
Depreciation and amortization	194	180
Taxes other than income taxes	114	111
Total operating expenses	1,000	1,053
Gain on sales of assets	2	—
Operating income	173	175
Other income and (deductions)		
Interest expense, net	(67)	(65)
Other, net	13	12
Total other income and (deductions)	(54)	(53)
Income before income taxes	119	122
Income taxes	11	5
Net income	\$ 108	\$ 117
Comprehensive income	\$ 108	\$ 117

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,	
	2020	2019
Cash flows from operating activities		
Net income	\$ 108	\$ 117
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	194	180
Deferred income taxes and amortization of investment tax credits	(4)	—
Other non-cash operating activities	7	35
Changes in assets and liabilities:		
Accounts receivable	36	(11)
Receivables from and payables to affiliates, net	(17)	(8)
Inventories	8	(12)
Accounts payable and accrued expenses	(16)	(9)
Income taxes	15	4
Pension and non-pension postretirement benefit contributions	(27)	(6)
Other assets and liabilities	(72)	(61)
Net cash flows provided by operating activities	232	229
Cash flows from investing activities		
Capital expenditures	(376)	(358)
Other investing activities	1	1
Net cash flows used in investing activities	(375)	(357)
Cash flows from financing activities		
Changes in short-term borrowings	(100)	147
Issuance of long-term debt	150	—
Retirement of long-term debt	(6)	(5)
Change in Exelon intercompany money pool	7	—
Distributions to member	(134)	(128)
Contributions from member	144	19
Other financing activities	(1)	—
Net cash flows provided by financing activities	60	33
Decrease in cash, cash equivalents and restricted cash	(83)	(95)
Cash, cash equivalents and restricted cash at beginning of period	181	186
Cash, cash equivalents and restricted cash at end of period	\$ 98	\$ 91
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (57)	\$ (55)

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 49	\$ 131
Restricted cash and cash equivalents	37	36
Accounts receivable		
Customer accounts receivable	471	516
Customer allowance for credit losses	(42)	(37)
Customer accounts receivable, net	429	479
Other accounts receivable	197	190
Other allowance for credit losses	(18)	(16)
Other accounts receivable, net	179	174
Receivable from affiliates	1	1
Inventories, net		
Fossil fuel	3	8
Materials and supplies	187	190
Regulatory assets	427	412
Other	57	49
Total current assets	1,369	1,480
Property, plant and equipment (net of accumulated depreciation and amortization of \$1,319 and \$1,213 as of March 31, 2020 and December 31, 2019, respectively)	14,491	14,296
Deferred debits and other assets		
Regulatory assets	2,012	2,061
Investments	135	135
Goodwill	4,005	4,005
Prepaid pension asset	412	406
Deferred income taxes	13	13
Other	316	323
Total deferred debits and other assets	6,893	6,943
Total assets^(a)	\$ 22,753	\$ 22,719

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ 108	\$ 208
Long-term debt due within one year	144	103
Accounts payable	423	462
Accrued expenses	280	296
Payables to affiliates	82	98
Borrowings from Exelon intercompany money pool	19	12
Customer deposits	117	117
Regulatory liabilities	70	70
Unamortized energy contract liabilities	109	115
Other	129	131
Total current liabilities	1,481	1,612
Long-term debt	6,564	6,460
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,302	2,278
Asset retirement obligations	57	57
Non-pension postretirement benefit obligations	89	93
Regulatory liabilities	1,675	1,707
Unamortized energy contract liabilities	307	327
Other	552	577
Total deferred credits and other liabilities	4,982	5,039
Total liabilities ^(a)	13,027	13,111
Commitments and contingencies		
Member's equity		
Membership interest	9,762	9,618
Undistributed losses	(36)	(10)
Total member's equity	9,726	9,608
Total liabilities and member's equity	\$ 22,753	\$ 22,719

(a) PHI's consolidated total assets include \$22 million and \$20 million at March 31, 2020 and December 31, 2019, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include \$43 million and \$44 million at March 31, 2020 and December 31, 2019, 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 EQUITY
(Unaudited)**

<i>(In millions)</i>	Three Months Ended March 31, 2020		
	Membership Interest	Undistributed Earnings (Losses)	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

<i>(In millions)</i>	Three Months Ended March 31, 2019		
	Membership Interest	Undistributed Earnings (Losses)	Member's Equity
Balance, December 31, 2018	\$ 9,220	\$ 62	\$ 9,282
Net income	—	117	117
Distributions to member	—	(128)	(128)
Contributions from member	19	—	19
Balance, March 31, 2019	\$ 9,239	\$ 51	\$ 9,290

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	Three Months Ended March 31,	
	2020	2019
Operating revenues		
Electric operating revenues	\$ 528	\$ 559
Revenues from alternative revenue programs	15	14
Operating revenues from affiliates	1	2
Total operating revenues	544	575
Operating expenses		
Purchased power	85	117
Purchased power from affiliates	79	70
Operating and maintenance	60	64
Operating and maintenance from affiliates	51	54
Depreciation and amortization	95	94
Taxes other than income taxes	92	92
Total operating expenses	462	491
Operating income	82	84
Other income and (deductions)		
Interest expense, net	(34)	(34)
Other, net	9	7
Total other income and (deductions)	(25)	(27)
Income before income taxes	57	57
Income taxes	5	2
Net income	\$ 52	\$ 55
Comprehensive income	\$ 52	\$ 55

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31,	
	2020	2019
Cash flows from operating activities		
Net income	\$ 52	\$ 55
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	95	94
Deferred income taxes and amortization of investment tax credits	(2)	(2)
Other non-cash operating activities	(11)	3
Changes in assets and liabilities:		
Accounts receivable	14	(19)
Receivables from and payables to affiliates, net	(11)	3
Inventories	3	(14)
Accounts payable and accrued expenses	6	(2)
Income taxes	6	4
Pension and non-pension postretirement benefit contributions	(4)	(4)
Other assets and liabilities	(38)	(37)
Net cash flows provided by operating activities	110	81
Cash flows from investing activities		
Capital expenditures	(180)	(144)
Changes in PHI intercompany money pool	(114)	—
Other investing activities	(4)	1
Net cash flows used in investing activities	(298)	(143)
Cash flows from financing activities		
Changes in short-term borrowings	(82)	65
Issuance of long-term debt	150	—
Dividends paid on common stock	(28)	(24)
Contributions from parent	137	14
Other financing activities	(1)	—
Net cash flows provided by financing activities	176	55
Decrease in cash, cash equivalents and restricted cash	(12)	(7)
Cash, cash equivalents and restricted cash at beginning of period	63	53
Cash, cash equivalents and restricted cash at end of period	\$ 51	\$ 46
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (43)	\$ (15)

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 18	\$ 30
Restricted cash and cash equivalents	33	33
Accounts receivable		
Customer accounts receivable	225	244
Customer allowance for credit losses	(15)	(13)
Customer accounts receivable, net	210	231
Other accounts receivable	102	98
Other allowance for credit losses	(8)	(7)
Other accounts receivable, net	94	91
Receivable from PHI intercompany money pool	114	—
Inventories, net	109	112
Regulatory assets	198	188
Other	24	11
Total current assets	800	696
Property, plant and equipment (net of accumulated depreciation and amortization of \$3,561 and \$3,517 as of March 31, 2020 and December 31, 2019, respectively)	7,002	6,909
Deferred debits and other assets		
Regulatory assets	567	584
Investments	111	110
Prepaid pension asset	293	296
Other	64	66
Total deferred debits and other assets	1,035	1,056
Total assets	\$ 8,837	\$ 8,661

See the Combined Notes to Consolidated Financial Statements

**POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)**

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ —	\$ 82
Long-term debt due within one year	3	2
Accounts payable	171	195
Accrued expenses	151	156
Payables to affiliates	55	66
Customer deposits	57	57
Regulatory liabilities	12	8
Merger related obligation	39	39
Current portion of DC PLUG obligation	30	30
Other	22	22
Total current liabilities	540	657
Long-term debt	3,012	2,862
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,143	1,131
Asset retirement obligations	41	41
Non-pension postretirement benefit obligations	16	20
Regulatory liabilities	731	746
Other	286	297
Total deferred credits and other liabilities	2,217	2,235
Total liabilities	5,769	5,754
Commitments and contingencies		
Shareholder's equity		
Common stock	1,933	1,796
Retained earnings	1,135	1,111
Total shareholder's equity	3,068	2,907
Total liabilities and shareholder's equity	\$ 8,837	\$ 8,661

See the Combined Notes to Consolidated Financial Statements

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

<i>(In millions)</i>	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

<i>(In millions)</i>	Three Months Ended March 31, 2019		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	\$ 1,636	\$ 1,104	\$ 2,740
Net income	—	55	55
Common stock dividends	—	(24)	(24)
Contributions from parent	14	—	14
Balance, March 31, 2019	\$ 1,650	\$ 1,135	\$ 2,785

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	Three Months Ended March 31,	
	2020	2019
Operating revenues		
Electric operating revenues	\$ 283	\$ 307
Natural gas operating revenues	64	71
Revenues from alternative revenue programs	1	—
Operating revenues from affiliates	2	2
Total operating revenues	350	380
Operating expenses		
Purchased power	88	107
Purchased fuel	31	34
Purchased power from affiliate	22	23
Operating and maintenance	42	45
Operating and maintenance from affiliates	37	39
Depreciation and amortization	48	46
Taxes other than income taxes	16	14
Total operating expenses	284	308
Operating income	66	72
Other income and (deductions)		
Interest expense, net	(16)	(15)
Other, net	2	3
Total other income and (deductions)	(14)	(12)
Income before income taxes	52	60
Income taxes	7	7
Net income	\$ 45	\$ 53
Comprehensive income	\$ 45	\$ 53

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended March 31,	
	2020	2019
Cash flows from operating activities		
Net income	\$ 45	\$ 53
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	48	46
Deferred income taxes and amortization of investment tax credits	—	1
Other non-cash operating activities	2	11
Changes in assets and liabilities:		
Accounts receivable	14	(5)
Receivables from and payables to affiliates, net	(9)	(15)
Inventories	3	1
Accounts payable and accrued expenses	4	11
Income taxes	7	5
Other assets and liabilities	(10)	(10)
Net cash flows provided by operating activities	104	98
Cash flows from investing activities		
Capital expenditures	(95)	(78)
Other investing activities	(4)	—
Net cash flows used in investing activities	(99)	(78)
Cash flows from financing activities		
Changes in short-term borrowings	(2)	5
Changes in PHI intercompany money pool	37	—
Dividends paid on common stock	(52)	(41)
Contributions from parent	6	—
Net cash flows used in financing activities	(11)	(36)
Decrease in cash, cash equivalents and restricted cash	(6)	(16)
Cash, cash equivalents and restricted cash at beginning of period	13	24
Cash, cash equivalents and restricted cash at end of period	\$ 7	\$ 8
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (9)	\$ (17)

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 7	\$ 13
Accounts receivable		
Customer accounts receivable	139	152
Customer allowance for credit losses	(13)	(11)
Customer accounts receivable, net	126	141
Other accounts receivable	40	42
Other allowance for credit losses	(4)	(4)
Other accounts receivable, net	36	38
Receivables from affiliates	1	—
Inventories, net		
Fossil fuel	3	8
Materials and supplies	46	44
Prepaid utility taxes	9	18
Regulatory assets	50	52
Renewable energy credits	16	9
Other	2	2
Total current assets	296	325
Property, plant and equipment (net of accumulated depreciation and amortization of \$1,452 and \$1,425 as of March 31, 2020 and December 31, 2019, respectively)	4,088	4,035
Deferred debits and other assets		
Regulatory assets	221	222
Goodwill	8	8
Prepaid pension asset	169	171
Other	67	69
Total deferred debits and other assets	465	470
Total assets	\$ 4,849	\$ 4,830

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ 54	\$ 56
Long-term debt due within one year	81	80
Accounts payable	98	112
Accrued expenses	62	46
Payables to affiliates	21	32
Borrowings from PHI intercompany money pool	37	—
Customer deposits	35	36
Regulatory liabilities	35	37
Other	14	15
Total current liabilities	437	414
Long-term debt	1,494	1,487
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	665	655
Non-pension postretirement benefits obligations	15	16
Regulatory liabilities	561	574
Other	98	104
Total deferred credits and other liabilities	1,339	1,349
Total liabilities	3,270	3,250
Commitments and contingencies		
Shareholder's equity		
Common stock	983	977
Retained earnings	596	603
Total shareholder's equity	1,579	1,580
Total liabilities and shareholder's equity	\$ 4,849	\$ 4,830

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	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

<u>(In millions)</u>	Three Months Ended March 31, 2019		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	\$ 914	\$ 595	\$ 1,509
Net income	—	53	53
Common stock dividends	—	(41)	(41)
Balance, March 31, 2019	\$ 914	\$ 607	\$ 1,521

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	Three Months Ended March 31,	
	2020	2019
Operating revenues		
Electric operating revenues	\$ 274	\$ 271
Revenues from alternative revenue programs	1	1
Operating revenues from affiliates	1	1
Total operating revenues	276	273
Operating expenses		
Purchased power	126	131
Purchased power from affiliates	2	8
Operating and maintenance	45	47
Operating and maintenance from affiliates	33	34
Depreciation and amortization	43	31
Taxes other than income taxes	2	1
Total operating expenses	251	252
Gain on sale of assets	2	—
Operating income	27	21
Other income and (deductions)		
Interest expense, net	(14)	(14)
Interest expense to affiliates, net	(1)	—
Other, net	2	3
Total other income and (deductions)	(13)	(11)
Income before income taxes	14	10
Income taxes	1	—
Net income	\$ 13	\$ 10
Comprehensive income	\$ 13	\$ 10

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,	
	2020	2019
Cash flows from operating activities		
Net income	\$ 13	\$ 10
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	43	31
Deferred income taxes and amortization of investment tax credits	(1)	—
Other non-cash operating activities	4	5
Changes in assets and liabilities:		
Accounts receivable	11	13
Receivables from and payables to affiliates, net	3	(4)
Inventories	2	1
Accounts payable and accrued expenses	3	12
Income taxes	2	(1)
Pension and non-pension postretirement benefit contributions	(2)	—
Other assets and liabilities	(22)	(7)
Net cash flows provided by operating activities	56	60
Cash flows from investing activities		
Capital expenditures	(101)	(128)
Other investing activities	6	—
Net cash flows used in investing activities	(95)	(128)
Cash flows from financing activities		
Changes in short-term borrowings	(16)	77
Retirement of long-term debt	(5)	(4)
Changes in PHI intercompany money pool	77	—
Dividends paid on common stock	(23)	(12)
Contributions from parent	1	5
Net cash flows provided by financing activities	34	66
Decrease in cash, cash equivalents and restricted cash	(5)	(2)
Cash, cash equivalents and restricted cash at beginning of period	28	30
Cash, cash equivalents and restricted cash at end of period	\$ 23	\$ 28
Supplemental cash flow information		
Decrease in capital expenditures not paid	\$ (4)	\$ (24)

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
ASSETS		
Current assets		
Cash and cash equivalents	\$ 8	\$ 12
Restricted cash and cash equivalents	3	2
Accounts receivable		
Customer accounts receivable	106	121
Customer allowance for credit losses	(14)	(13)
Customer accounts receivable, net	92	108
Other accounts receivable	54	53
Other allowance for credit losses	(6)	(5)
Other accounts receivable, net	48	48
Receivables from affiliates	4	4
Inventories, net	32	34
Regulatory assets	71	57
Other	3	5
Total current assets	261	270
Property, plant and equipment (net of accumulated depreciation and amortization of \$1,236 and \$1,210 as of March 31, 2020 and December 31, 2019, respectively)	3,249	3,190
Deferred debits and other assets		
Regulatory assets	366	368
Prepaid pension asset	51	52
Other	51	53
Total deferred debits and other assets	468	473
Total assets^(a)	\$ 3,978	\$ 3,933

See the Combined Notes to Consolidated Financial Statements

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

<u>(In millions)</u>	<u>March 31, 2020</u>	<u>December 31, 2019</u>
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	\$ 54	\$ 70
Long-term debt due within one year	60	20
Accounts payable	145	144
Accrued expenses	40	42
Payables to affiliates	27	25
Borrowings from PHI intercompany money pool	77	—
Customer deposits	25	25
Regulatory liabilities	24	25
Other	8	9
Total current liabilities	460	360
Long-term debt	1,265	1,307
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	580	577
Non-pension postretirement benefit obligations	17	17
Regulatory liabilities	352	357
Other	37	39
Total deferred credits and other liabilities	986	990
Total liabilities^(a)	2,711	2,657
Commitments and contingencies		
Shareholder's equity		
Common stock	1,155	1,154
Retained earnings	112	122
Total shareholder's equity	1,267	1,276
Total liabilities and shareholder's equity	\$ 3,978	\$ 3,933

(a) ACE's consolidated total assets include \$15 million and \$17 million at March 31, 2020 and December 31, 2019, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated total liabilities include \$36 million and \$41 million at March 31, 2020 and December 31, 2019, 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)

<u>(In millions)</u>	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

<u>(In millions)</u>	Three Months Ended March 31, 2019		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2018	\$ 979	\$ 147	\$ 1,126
Net income	—	10	10
Common stock dividends	—	(12)	(12)
Contributions from parent	5	—	5
Balance, March 31, 2019	\$ 984	\$ 145	\$ 1,129

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)

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, 2020 and 2019 and for the three months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2019 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

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

Note 1 — Significant Accounting Policies

December 31, 2020. 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.

COVID-19 (All Registrants)

The Registrants are responding to the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19) and have taken steps to mitigate the potential risks to the Registrants posed by its spread. The Registrants provide a critical service to their customers and have 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. The Registrants have implemented work from home policies where appropriate and imposed travel limitations on employees. In addition, the Registrants have updated their 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. We assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, our allowance for credit losses, the carrying value of our goodwill and other long-lived assets, in context with the information reasonably available to us and the unknown future impacts of COVID-19 as of March 31, 2020 and through the date of this report. While there were no material increases in the Registrants' allowance for credit losses and no material impairments resulting from these assessments as of and for the quarter ended March 31, 2020, our future assessment of our current expectations at that time of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts to our consolidated financial statements in future reporting periods.

New Accounting Standards (All Registrants)

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 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 credit losses 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 Generation's and the Utility Registrants' Customer accounts receivables balances. This guidance did not have a significant impact on the Registrants' consolidated financial statements.

Goodwill Impairment (Issued January 2017). Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, 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 test). 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. Exelon, Generation, ComEd, PHI and DPL will apply the new guidance for their goodwill impairment assessments in 2020 and do not expect the updated guidance to have a material impact to their financial statements.

Allowance for Credit Losses on Accounts Receivables (All Registrants)

The allowance for credit losses reflects the Registrants' best estimates of losses on the customers' accounts receivable balances based on historical experience, current information, and reasonable and supportable forecasts.

The allowance for credit losses for Generation's retail customers is based on accounts receivable aging historical experience coupled with specific identification through a credit monitoring process, which considers current

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

Note 1 — Significant Accounting Policies

conditions and forward-looking information such as industry trends, macroeconomic factors, changes in the regulatory environment, external credit ratings, publicly available news, payment status, payment history, and the exercise of collateral calls. The allowance for credit losses for Generation wholesale customers is developed using a credit monitoring process, similar to that used for retail customers. When a wholesale customer's risk characteristics are no longer aligned with the pooled population, Generation uses specific identification to develop an allowance for credit losses. Adjustments to the allowance for credit losses are recorded in Operating and maintenance expense on Generation's Consolidated Statements of Operations and Comprehensive Income.

The allowance for credit losses for the Utility Registrants' customers is developed by applying loss rates for each Utility Registrant, based on historical loss experience, current conditions and forward-looking risk factors, to the outstanding receivable balance by customer risk segment. Utility Registrants' customer accounts are written off consistent with approved regulatory requirements. Adjustments to the allowance for credit losses are primarily recorded to Operating and maintenance expense on the Utility Registrants' Consolidated Statements of Operations and Comprehensive Income and Regulatory assets on ComEd, BGE and ACE's Consolidated Balance Sheets. See Note 3 - Regulatory Matters of the 2019 Form 10-K for additional information regarding the regulatory recovery of credit losses on customer accounts receivable at ComEd, BGE and ACE.

The Registrants have 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 credit losses related to these receivables is immaterial. The Registrants monitor these balances and will record an allowance if there are indicators of a decline in credit quality.

2. Regulatory Matters (All Registrants)

As discussed in Note 3 — Regulatory Matters of the Exelon 2019 Form 10-K, the Registrants are involved in rate and regulatory proceedings at the FERC and their state commissions. The following discusses developments in 2020 and updates to the 2019 Form 10-K.

Utility Regulatory Matters (Exelon and the Utility Registrants)

Distribution Base Rate Case Proceedings

The following tables show the completed and pending distribution base rate case proceedings in 2020.

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

Note 2 — Regulatory Matters

Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois (Electric) ^(a)	April 8, 2019	\$ (6)	\$ (17)	8.91%	December 4, 2019	January 1, 2020

(a) Reflects an increase of \$51 million for the initial revenue requirement for 2019 and a decrease of \$68 million related to the annual reconciliation for 2018. The revenue requirement for 2019 and annual reconciliation for 2018 provides for a weighted average debt and equity return on distribution rate base of 6.51%, inclusive of an allowed ROE of 8.91%, reflecting the average rate on 30-year treasury notes plus 580 basis points.

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement (Decrease) Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois (Electric) ^(a)	April 16, 2020	\$ (11)	8.38%	Fourth quarter of 2020
Pepco - District of Columbia (Electric) ^(b)	May 30, 2019 (amended April 8, 2020)	147	10.3%	Fourth quarter of 2020
DPL - Maryland (Electric)	December 5, 2019 (amended April 23, 2020)	17	10.3%	Third quarter of 2020
DPL - Delaware (Gas) ^(c)	February 21, 2020 (amended March 17, 2020)	9	10.3%	First quarter of 2021
DPL - Delaware (Electric) ^(d)	March 6, 2020 (amended April 16, 2020)	24	10.3%	First quarter of 2021

(a) Reflects an increase of \$51 million for the initial revenue requirement for 2020 and a decrease of \$62 million related to the annual reconciliation for 2019. The revenue requirement for 2020 and annual reconciliation for 2019 provides 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 average rate on 30-year treasury notes plus 580 basis points.

(b) Reflects a three-year cumulative multi-year plan and total requested revenue requirement increases of \$77 million, \$37 million and \$33 million for years 2020, 2021, and 2022, respectively, to recover capital investments made in 2018 and 2019 and planned capital investments from 2020 to 2022.

(c) The rates will go into effect on September 21, 2020, subject to refund.

(d) The rates will go into effect on October 6, 2020, subject to refund.

Other Federal Regulatory Matters

Transmission-Related Income Tax Regulatory Assets (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). On December 13, 2016 (and as amended on March 13, 2017), 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

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

Note 2 — Regulatory Matters

these transmission-related income tax regulatory assets. In the fourth quarter of 2017, ComEd, BGE, Pepco, DPL, and ACE fully impaired their associated transmission-related income tax regulatory asset for the portion of the income tax regulatory asset that would have been previously amortized.

On February 23, 2018 (as amended on July 9, 2018), ComEd, Pepco, DPL, and ACE each 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) February 23, 2018 (as amended on July 9, 2018) filing by ComEd, Pepco, DPL and ACE for similar recovery.

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

On October 1, 2018, ComEd, BGE, Pepco, DPL, and ACE submitted filings to recover only ongoing non-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 ComEd's, BGE's, Pepco's, DPL's, and ACE's October 1, 2018 filings, effective October 1, 2018, subject to refund and established hearing and settlement judge procedures. On April 24, 2020, ComEd, BGE, Pepco, DPL, ACE and other parties filed a settlement agreement with FERC. 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 accelerated amortization will result in a reduction to Operating revenues and an offsetting reduction to Income tax expense over the remaining amortization period.

While FERC has no deadline by which it must rule on the settlement, a final order from FERC is expected before the end of the third quarter of 2020. Exelon cannot predict the outcome of this proceeding. If FERC ultimately rules that the future, ongoing non-TCJA amortization amounts are not recoverable, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE would record additional charges to Income tax expense, which could be up to approximately \$81 million, \$51 million, \$18 million, \$12 million, \$4 million, \$6 million and \$2 million, respectively, as of March 31, 2020.

Regulatory Assets and Liabilities

The Utility Registrants' regulatory assets and liabilities have not changed materially since December 31, 2019, unless noted below. See Note 3 — Regulatory Matters of the Exelon 2019 Form 10-K for additional information on the specific regulatory assets and liabilities.

ComEd. Regulatory assets increased \$96 million primarily due to an increase of \$45 million in Energy Efficiency Costs, \$22 million in Electric Distribution Formula Rate Annual Reconciliations and \$15 million due to increased Electric Energy Costs. Regulatory liabilities decreased \$596 million primarily due to a decrease of \$582 million in Nuclear Decommissioning.

PECO. Regulatory liabilities decreased \$207 million primarily due to a decrease of \$219 million in Nuclear Decommissioning offset by a \$16 million increase in Electric Energy and Natural Gas Costs.

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

Note 2 — Regulatory Matters

Capitalized Ratemaking Amounts Not Recognized (Exelon and the Utility Registrants)

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 our customers.

	Exelon	ComEd ^(a)	PECO	BGE ^(b)	PHI	Pepco ^(c)	DPL ^(c)	ACE
March 31, 2020	\$ 60	\$ 2	\$ —	\$ 51	\$ 7	\$ 4	\$ 3	\$ —
December 31, 2019	63	3	—	53	7	4	3	—

- (a) Reflects ComEd's unrecognized equity returns earned 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)

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 and has recognized \$18 million for the three months ended March 31, 2020. On May 15, 2019, New Jersey Rate Counsel appealed the NJBPU's decision to the New Jersey Superior Court. Exelon and Generation cannot predict the outcome of the appeal. See Note 6 — Early Plant Retirements for additional information related to Salem.

New York Regulatory Matters

New York Clean Energy Standard. On August 1, 2016, the NYPSC issued an order establishing the New York CES, a component of which is a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC to be Generation's FitzPatrick, Ginna and Nine Mile Point nuclear facilities.

On November 30, 2016 (as amended on January 13, 2017), a group of parties filed a Petition in New York State court seeking to invalidate the ZEC program, which argued that the NYPSC did not have authority to establish the program, that it violated state environmental law and that it violated certain technical provisions of the State Administrative Procedures Act when adopting the ZEC program. On January 22, 2018, the court dismissed the environmental claims and the majority of the plaintiffs from the case but denied the motions to dismiss with respect to the remaining five plaintiffs and claims, without commenting on the merits of the case. On October 8, 2019, the court dismissed all remaining claims. The petitioners filed a notice of appeal on November 4, 2019 and originally had until May 4, 2020 to file their brief. However, on March 17, 2020, the court suspended all filing deadlines indefinitely due to COVID-19, so the new deadline will not be known until the court lifts the suspension.

See Note 6 — Early Plant Retirements for additional information related to Ginna and Nine Mile Point.

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

Note 2 — Regulatory Matters

Federal Regulatory Matters

PJM and NYISO MOPR Proceedings. PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR). If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a government-provided financial support program - resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the MOPR in PJM applied only to certain new gas-fired resources. Currently, the MOPR in NYISO applies only to certain resources in downstate New York.

For Generation's facilities in PJM and NYISO that are currently receiving ZEC compensation, an expanded MOPR would require exclusion of ZEC compensation when bidding into future capacity auctions, resulting in an increased risk of these facilities not receiving capacity revenues in future auctions. While FERC issued a set of orders on MOPR in NYISO on February 20, 2020, it did not expand mitigation to include Generation's nuclear assets in upstate New York. However, FERC has taken action to expand the MOPR in PJM.

Specifically, on December 19, 2019, FERC issued an order in the PJM MOPR proceeding that broadly applies the MOPR to all new and existing resources including nuclear, renewables, demand response, energy efficiency, storage and all resources owned by vertically-integrated utilities, greatly expanding the breadth and scope of PJM's MOPR, effective as of PJM's next capacity auction. While FERC included some limited exemptions (generally available to existing renewable, energy efficiency, demand response, storage and existing vertically-integrated utility resources) in its order, no exemptions were available to state-supported nuclear resources. In addition, FERC provided no new mechanism for accommodating state-supported resources other than the existing FRR mechanism under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone. FERC directed PJM to make a compliance filing within 90 days, which was filed on March 18, 2020. In that filing, PJM proposes tariff language interpreting and implementing FERC's directives and proposes a schedule for resuming capacity auctions that is contingent on the timing of FERC's action on the compliance filing. FERC has no deadline for such action, and FERC could accept, reject or direct further revisions to all or part of PJM's proposed tariff revisions and auction schedule. In addition, on April 16, 2020, FERC issued orders largely denying requests for rehearing of FERC's December 2019 order and another order in this proceeding. In those orders, FERC also granted a few clarifications that will require an additional PJM compliance filing that could also delay the timing for FERC to issue its compliance order(s) and PJM to resume its capacity auctions.

Unless Illinois and New Jersey can implement an FRR program in their PJM zones, the MOPR will apply to Generation's owned or jointly owned nuclear plants in those states receiving a benefit under the Illinois ZES or the New Jersey ZEC program, as applicable, increasing the risk that those units may not clear the capacity market.

Exelon is currently working with PJM and other stakeholders to pursue the FRR option prior to the next capacity auction in PJM. If Illinois implements the FRR option, Generation's Illinois nuclear plants could be removed from PJM's capacity auction and instead supply capacity and be compensated under the FRR program, which has the potential to mitigate the current economic distress being experienced by Generation's nuclear plants in Illinois, as discussed in Note 6 - Early Plant Retirements. Implementing the FRR program in Illinois will require both legislative and regulatory changes. Legislation may be introduced in New Jersey as well. Exelon cannot predict whether such legislative and regulatory changes can be implemented prior to the next capacity auction in PJM.

If Generation's state-supported nuclear plants in PJM are subjected to the MOPR or equivalent without compensation under an FRR or similar program, it could have a material adverse impact on Exelon's and Generation's financial statements, which Exelon and Generation cannot reasonably estimate at this time.

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 has been working with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

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

Note 2 — Regulatory Matters

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. Among the Proposed License Articles are modifications to river flows to improve aquatic habitat, eel passage improvements and initiatives to support rare, threatened and endangered wildlife. If FERC approves the Offer of Settlement and incorporates the Proposed License Articles into the new license without modification, then MDE would waive its rights to issue a 401 Certification and Generation would agree, pursuant to a separate agreement with MDE (MDE Settlement), to implement additional environmental protection, mitigation and enhancement measures over the anticipated 50-year term of the new license. These measures address mussel restoration and other ecological and water quality matters, among other commitments. Exelon's commitments under the various provisions of the Offer of Settlement and MDE Settlement are not effective unless and until FERC approves the Offer of Settlement and issues the new license with the Proposed License Articles. Generation cannot currently predict when FERC will issue the new license.

Peach Bottom Units 2 and 3. On July 10, 2018, Generation submitted a second 20-year license renewal application with the NRC for Peach Bottom Units 2 and 3, which was approved on March 6, 2020. Peach Bottom Units 2 and 3 are now licensed to operate through 2053 and 2054, respectively.

3. Revenue from Contracts with Customers (All Registrants)

The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that the entities expect to be entitled to in exchange for those goods or services. 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 2019 Form 10-K for additional information regarding the primary sources of revenue for the Registrants.

Contract Balances (All Registrants)

Contract Assets and Liabilities

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.

Generation records contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. These contract liabilities primarily relate to upfront consideration received or due for equipment service plans, solar panel leases and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation. Generation records contract liabilities within Other current liabilities and Other noncurrent liabilities within 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 3 — Revenue from Contracts with Customers

The following table provides a rollforward of the contract assets and liabilities reflected in Exelon's and Generation's Consolidated Balance Sheets for the three months ended March 31, 2019 and March 31, 2020

	Contract Assets		Contract Liabilities	
	Exelon	Generation	Exelon	Generation
Balance as of December 31, 2018	\$ 187	\$ 187	\$ 27	\$ 42
Consideration received or due	(26)	(26)	21	63
Revenues recognized ^(a)	26	26	(23)	(66)
Balance at March 31, 2019	<u>\$ 187</u>	<u>\$ 187</u>	<u>\$ 25</u>	<u>\$ 39</u>
Balance as of December 31, 2019	\$ 174	\$ 174	\$ 33	\$ 71
Consideration received or due	(19)	(19)	20	55
Revenues recognized ^(b)	17	17	(24)	(70)
Balance at March 31, 2020	<u>\$ 172</u>	<u>\$ 172</u>	<u>\$ 29</u>	<u>\$ 56</u>

(a) Revenues recognized in the three months ended March 31, 2019, which were included in contract liabilities at December 31, 2018, were approximately \$5 million for both Exelon and Generation.

(b) Revenues recognized in the three months ended March 31, 2020, which were included in contract liabilities at December 31, 2019, were approximately \$9 million and \$19 million for Exelon and Generation, respectively.

The Utility Registrants do not have any contract assets. The Utility Registrants also record contract liabilities when consideration is received prior to the satisfaction of the performance obligations. As of March 31, 2020 and December 31, 2019, the Utility Registrants' contract liabilities were immaterial.

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, 2020. 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.

	2020	2021	2022	2023	2024 and thereafter	Total
Exelon	\$ 273	\$ 144	\$ 64	\$ 45	\$ 198	\$ 724
Generation	330	200	79	45	198	852

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 4 — Segment Information for the presentation of the Registrant's revenue disaggregation.

4. 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"

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

Note 4 — Segment Information

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, 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, 2020 and 2019 is as follows:

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

Note 4 — Segment Information

Three Months Ended March 31, 2020 and 2019

	Generation ^(a)	ComEd	PECO	BGE	PHI	Other ^(b)	Intersegment Eliminations	Exelon
Operating revenues^(c):								
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	\$ 4,733	\$ 1,439	\$ 813	\$ 937	\$ 1,171	\$ 480	\$ (826)	\$ 8,747
2019								
Competitive businesses electric revenues	\$ 4,337	\$ —	\$ —	\$ —	\$ —	\$ —	\$ (315)	\$ 4,022
Competitive businesses natural gas revenues	879	—	—	—	—	—	(1)	878
Competitive businesses other revenues	80	—	—	—	—	—	(1)	79
Rate-regulated electric revenues	—	1,408	620	658	1,153	—	(8)	3,831
Rate-regulated natural gas revenues	—	—	280	318	71	—	(4)	665
Shared service and other revenues	—	—	—	—	4	455	(457)	2
Total operating revenues	\$ 5,296	\$ 1,408	\$ 900	\$ 976	\$ 1,228	\$ 455	\$ (786)	\$ 9,477
Intersegment revenues^(d):								
2020	\$ 330	\$ 5	\$ 2	\$ 6	\$ 3	\$ 479	\$ (824)	\$ 1
2019	317	4	1	6	4	453	(785)	—
Depreciation and amortization:								
2020	\$ 304	\$ 273	\$ 86	\$ 143	\$ 194	\$ 21	\$ —	\$ 1,021
2019	405	251	81	136	180	22	—	1,075
Operating expenses:								
2020	\$ 4,400	\$ 1,151	\$ 625	\$ 688	\$ 1,000	\$ 481	\$ (816)	\$ 7,529
2019	4,963	1,135	678	756	1,054	459	(783)	8,262
Interest expense, net:								
2020	\$ 109	\$ 94	\$ 36	\$ 32	\$ 67	\$ 72	\$ —	\$ 410
2019	111	87	33	29	65	78	—	403

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

Note 4 — Segment Information

	Generation ^(a)	ComEd	PECO	BGE	PHI	Other ^(b)	Intersegment Eliminations	Exelon
Income (loss) before income taxes:								
2020	\$ (547)	\$ 204	\$ 155	\$ 222	\$ 119	\$ (69)	\$ 1	\$ 85
2019	652	197	193	196	122	(78)	—	1,282
Income Taxes:								
2020	\$ (389)	\$ 36	\$ 15	\$ 41	\$ 11	\$ (8)	\$ —	\$ (294)
2019	224	40	25	36	5	(20)	—	310
Net income (loss):								
2020	\$ (161)	\$ 168	\$ 140	\$ 181	\$ 108	\$ (61)	\$ 1	\$ 376
2019	422	157	168	160	117	(58)	—	966
Capital Expenditures								
2020	\$ 558	\$ 506	\$ 259	\$ 283	\$ 376	\$ 34	\$ —	\$ 2,016
2019	511	503	222	258	358	21	—	1,873
Total assets:								
March 31, 2020	\$ 47,882	\$33,146	\$11,535	\$10,789	\$22,753	\$ 8,337	\$ (9,765)	\$ 124,677
December 31, 2019	48,995	32,765	11,469	10,634	22,719	8,484	(10,089)	124,977

(a) See Note 18 — Related Party Transactions for additional information on intersegment revenues.

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

(c) 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.

(d) 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.

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

Note 4 — Segment Information

PHI:

	Pepco	DPL	ACE	Other ^(b)	Intersegment Eliminations	PHI
Operating revenues^(a):						
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>
2019						
Rate-regulated electric revenues	\$ 575	\$ 310	\$ 273	\$ —	\$ (5)	\$ 1,153
Rate-regulated natural gas revenues	—	70	—	—	1	71
Shared service and other revenues	—	—	—	106	(102)	4
Total operating revenues	<u>\$ 575</u>	<u>\$ 380</u>	<u>\$ 273</u>	<u>\$ 106</u>	<u>\$ (106)</u>	<u>\$ 1,228</u>
Intersegment revenues:						
2020	\$ 1	\$ 2	\$ 1	\$ 92	\$ (93)	\$ 3
2019	2	2	1	105	(106)	4
Depreciation and amortization:						
2020	\$ 95	\$ 48	\$ 43	\$ 9	\$ (1)	\$ 194
2019	94	46	31	10	(1)	180
Operating expenses:						
2020	\$ 462	\$ 284	\$ 251	\$ 93	\$ (90)	\$ 1,000
2019	491	308	252	108	(105)	1,054
Interest expense, net:						
2020	\$ 34	\$ 16	\$ 15	\$ 3	\$ (1)	\$ 67
2019	34	15	14	3	(1)	65
Income (loss) before income taxes:						
2020	\$ 57	\$ 52	\$ 14	\$ 106	\$ (110)	\$ 119
2019	57	60	10	113	(118)	122
Income Taxes:						
2020	\$ 5	\$ 7	\$ 1	\$ (2)	\$ —	\$ 11
2019	2	7	—	(4)	—	5
Net income (loss):						
2020	\$ 52	\$ 45	\$ 13	\$ (5)	\$ 3	\$ 108
2019	55	53	10	(5)	4	117
Capital Expenditures						
2020	\$ 180	\$ 95	\$ 101	\$ —	\$ —	\$ 376
2019	144	78	128	8	—	358
Total assets:						
March 31, 2020	\$ 8,837	\$ 4,849	\$ 3,978	\$ 11,241	\$ (6,152)	\$ 22,753
December 31, 2019	8,661	4,830	3,933	11,105	(5,810)	22,719

(a) 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.

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

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

Note 4 — Segment Information

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 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, 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	\$ 4,307	\$ 426	\$ 4,733	\$ —	\$ 4,733

	Three Months Ended March 31, 2019				
	Revenues from external customers ^(a)			Intersegment revenues	Total Revenues
	Contracts with customers	Other ^(b)	Total		
Mid-Atlantic	\$ 1,286	\$ (24)	\$ 1,262	\$ (6)	\$ 1,256
Midwest	1,055	59	1,114	(6)	1,108
New York	409	(16)	393	—	393
ERCOT	130	79	209	3	212
Other Power Regions	1,165	194	1,359	(6)	1,353
Total Competitive Businesses Electric Revenues	4,045	292	4,337	(15)	4,322
Competitive Businesses Natural Gas Revenues	584	295	879	15	894
Competitive Businesses Other Revenues ^(c)	120	(40)	80	—	80
Total Generation Consolidated Operating Revenues	\$ 4,749	\$ 547	\$ 5,296	\$ —	\$ 5,296

(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 gains of \$179 million and losses of \$52 million in 2020 and 2019, respectively, and elimination of intersegment revenues.

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

Note 4 — Segment Information

Revenues net of purchased power and fuel expense (Generation):

	Three Months Ended March 31, 2020			Three Months Ended March 31, 2019		
	RNF from external customers ^(a)	Intersegment RNF	Total RNF	RNF from external customers ^(a)	Intersegment RNF	Total RNF
Mid-Atlantic	\$ 559	\$ 8	\$ 567	\$ 679	\$ 4	\$ 683
Midwest	732	(5)	727	769	2	771
New York	189	4	193	262	3	265
ERCOT	76	4	80	98	(24)	74
Other Power Regions	177	(19)	158	174	(18)	156
Total Revenues net of purchased power and fuel expense for Reportable Segments	1,733	(8)	1,725	1,982	(33)	1,949
Other ^(b)	296	8	304	109	33	142
Total Generation Revenues net of purchased power and fuel expense	\$ 2,029	\$ —	\$ 2,029	\$ 2,091	\$ —	\$ 2,091

(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. Includes unrealized mark-to-market gains of \$132 million and losses of \$28 million in 2020 and 2019, respectively and the elimination of intersegment RNF.

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

Note 4 — Segment Information

Electric and Gas Revenue by Customer Class (Utility Registrants):

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

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

Note 4 — Segment Information

Revenues from contracts with customers	Three Months Ended March 31, 2019						
	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	\$ 710	\$ 409	\$ 385	\$ 579	\$ 256	\$ 185	\$ 138
Small commercial & industrial	360	96	70	120	38	48	34
Large commercial & industrial	132	48	110	267	204	24	39
Public authorities & electric railroads	13	7	7	14	8	3	3
Other ^(a)	217	62	80	157	53	47	57
Total rate-regulated electric revenues^(b)	\$ 1,432	\$ 622	\$ 652	\$ 1,137	\$ 559	\$ 307	\$ 271
Rate-regulated natural gas revenues							
Residential	\$ —	\$ 198	\$ 219	\$ 44	\$ —	\$ 44	\$ —
Small commercial & industrial	—	72	35	19	—	19	—
Large commercial & industrial	—	1	50	1	—	1	—
Transportation	—	7	—	4	—	4	—
Other ^(c)	—	2	4	3	—	3	—
Total rate-regulated natural gas revenues^(d)	\$ —	\$ 280	\$ 308	\$ 71	\$ —	\$ 71	\$ —
Total rate-regulated revenues from contracts with customers	\$ 1,432	\$ 902	\$ 960	\$ 1,208	\$ 559	\$ 378	\$ 271
Other revenues							
Revenues from alternative revenue programs	\$ (28)	\$ (3)	\$ 10	\$ 15	\$ 14	\$ —	\$ 1
Other rate-regulated electric revenues ^(e)	4	1	3	4	2	1	1
Other rate-regulated natural gas revenues ^(e)	—	—	3	1	—	1	—
Total other revenues	\$ (24)	\$ (2)	\$ 16	\$ 20	\$ 16	\$ 2	\$ 2
Total rate-regulated revenues for reportable segments	\$ 1,408	\$ 900	\$ 976	\$ 1,228	\$ 575	\$ 380	\$ 273

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

(b) Includes operating revenues from affiliates of \$5 million, \$2 million, \$6 million, \$3 million, \$1 million, \$2 million and \$1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, in 2020 and \$4 million, \$1 million, \$2 million, \$3 million, \$2 million, \$2 million and \$1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, in 2019.

(c) Includes revenues from off-system natural gas sales.

(d) Includes operating revenues from affiliates of less than \$1 million and \$3 million at PECO and BGE, respectively, in 2020 and less than \$1 million and \$4 million at PECO and BGE, respectively, in 2019.

(e) Includes late payment charge revenues.

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

Note 5 — Accounts Receivable

5. Accounts Receivable (All Registrants)

Unbilled Customer Revenue

The following table provides additional information about unbilled customer revenues recorded in the Registrants' Consolidated Balance Sheets.

	Unbilled customer revenues ^(a)								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
March 31, 2020	\$ 1,225	\$ 698	\$ 160	\$ 96	\$ 134	\$ 137	\$ 75	\$ 42	\$ 20
December 31, 2019	1,535	807	218	146	170	194	100	61	33

(a) Unbilled customer revenues are classified in customer accounts receivables, net in the Registrants' Consolidated Balance Sheets.

Allowance for Credit Losses on Accounts Receivable

The following table presents the rollforward of Allowance for Credit Losses on Customer Accounts Receivable.

	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 ^(a)	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) Recoveries were not material to the Registrants.

The following table presents the rollforward of Allowance for Credit Losses on Other Accounts Receivable.

	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.

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

Note 5 — Accounts Receivable

Purchases and Sales of Customer and Other Accounts Receivables

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.

	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	—	—	—	—	—	—	—

6. 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 Three Mile Island 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 could again 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 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 2 — Regulatory Matters for additional information on the New Jersey ZEC program, New York CES and FERC's December 19, 2019 order and Note 3 — Regulatory Matters of the 2019 Form 10-K for additional information on the Illinois ZES.

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

Note 6 — Early Plant Retirements

In Pennsylvania, the TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year, the third consecutive year that TMI failed to clear the PJM base residual capacity auction and on May 30, 2017, based on these capacity auction results, prolonged periods of low wholesale power prices, and the absence of federal or state policies that place a value on nuclear energy for its ability to produce electricity without air pollution, Generation announced that it would permanently cease generation operations at TMI. On September 20, 2019, Generation permanently ceased generation operations at TMI.

As a result of the early nuclear plant retirement decision at TMI, Exelon and Generation recognized incremental non-cash charges to earnings stemming from shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC) and accelerated amortization of nuclear fuel, as well as operating and maintenance expenses. The total impact for the three months ended March 31, 2019 are summarized in the table below.

<u>Income statement expense (pre-tax)</u>	<u>Three Months Ended March 31, 2019</u>
Depreciation and amortization	
Accelerated depreciation	\$ 74
Accelerated nuclear fuel amortization	5
Operating and maintenance ^(a)	(83)
Total	\$ (4)

(a) Primarily reflects the net impacts associated with the remeasurement of the TMI ARO. See Note 9 — Asset Retirement Obligations of the 2019 Form 10-K for additional information.

Generation's Dresden, Byron and Braidwood nuclear plants in Illinois are also showing increased signs of economic distress, which could lead to an early retirement, 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. Exelon continues to work with stakeholders on state policy solutions, while also advocating for broader market reforms at the regional and federal level.

The following table provides the balance sheet amounts as of March 31, 2020 for Exelon's and Generation's significant assets and liabilities associated with these three nuclear plants. Depreciation provisions are based on the estimated useful lives of these nuclear generating stations, which reflect the first renewal of the operating licenses.

	<u>Dresden</u>	<u>Byron</u>	<u>Braidwood</u>	<u>Total</u>
Asset Balances				
Materials and supplies inventory, net	\$ 68	\$ 68	\$ 81	\$ 217
Nuclear fuel inventory, net	204	172	203	579
Completed plant, net	1,084	1,343	1,390	3,817
Construction work in progress	16	22	32	70
Liability Balances				
Asset retirement obligation	(1,301)	(596)	(554)	(2,451)
NRC License First Renewal Term	2029 (Unit 2) 2031 (Unit 3)	2044 (Unit 1) 2046 (Unit 2)	2046 (Unit 1) 2047 (Unit 2)	

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

Note 6 — Early Plant Retirements

Other Generation

On March 29, 2018, Generation notified grid operator ISO-NE of its plans to early retire its Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022, at the end of the then-current capacity commitment for Mystic Units 7 and 8. Mystic Unit 9 was then committed through May 2021.

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 and 9 for the period between June 1, 2022 - May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service agreement, 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 Everett Marine Terminal. Those adjustments were reflected in a compliance filing filed 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 March 25, 2019, ISO-NE filed the Inventoried Energy Program (IEP), which is intended to provide an interim fuel security program pending conclusion of the stakeholder process to develop a long-term, market-based solution to address fuel security. The IEP went into effect by operation of law on August 5, 2019 because FERC did not have a quorum at that time. On October 7, 2019, requests for rehearing were denied and several parties appealed to the D.C. Circuit Court. On April 14, 2020, FERC filed an unopposed motion asking the court for a voluntary remand of the IEP order, noting that FERC now has a quorum of Commissioners who can participate in the consideration of ISO-NE's IEP filing.

On April 15, 2020, ISO-NE filed its long-term, market-based fuel security proposal, proposing three new, day-ahead ancillary services products intended to compensate generators for operational capabilities that provide fuel security to the region. In the filing, ISO-NE also proposed to sunset the Fuel Security Retention Mechanism, through which Mystic has been retained for fuel security, and the IEP by June 1, 2024. In addition, the filing includes an alternate proposal sponsored by New England Power Pool, which includes substantive amendments to the ISO-NE proposal. ISO-NE requested a 30-day comment period and a November 1, 2020 effective date.

The following table provides the balance sheet amounts as of March 31, 2020 for Exelon's and Generation's significant assets and liabilities associated with the Mystic Units 8 and 9 and Everett Marine Terminal assets that would potentially be impacted by the failure to adopt long-term solutions for reliability and fuel security.

	March 31, 2020
Asset Balances	
Materials and supplies inventory	\$ 32
Fuel inventory	12
Property, plant and equipment, net	902
Liability Balances	
Asset retirement obligation	(3)

See Note 8 — Asset Impairments for impairment assessment considerations on the New England Asset Group.

7. 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 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.

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

Note 7 — Nuclear Decommissioning

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, 2019 to March 31, 2020:

Nuclear decommissioning ARO at December 31, 2019 ^(a)	\$	10,504
Accretion expense		121
Costs incurred related to decommissioning plants		(20)
Nuclear decommissioning ARO at March 31, 2020 ^(a)	\$	<u>10,605</u>

(a) Includes \$107 million and \$112 million as the current portion of the ARO at March 31, 2020 and December 31, 2019, respectively, 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 \$11,824 million and \$13,353 million at March 31, 2020 and December 31, 2019, respectively. The NDT funds also include \$213 million and \$163 million for the current portion of the NDT funds at March 31, 2020 and December 31, 2019, 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 April 1, 2019 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, 2018 for all units except for Clinton and Peach Bottom Unit 1. As of February 28, 2019, Clinton demonstrated adequate minimum funding assurance due to market recovery and no further action is required. This demonstration was also included in the April 1, 2019 submittal. On March 31, 2020, Generation filed its annual decommissioning funding status report with the NRC for Generation's shutdown units (excluding Zion Station for the reason noted above). The annual status report demonstrated adequate decommissioning funding assurance as of December 31, 2019, for all of its shutdown reactors except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund, collections from PECO ratepayers, and the ability to adjust those collections in accordance with the approved PAPUC tariff. No additional actions are required aside from the PAPUC filing in accordance with the tariff. See Note 9 — Asset Retirement Obligations of the Exelon 2019 Form 10-K for information regarding the amount collected from PECO ratepayers for decommissioning cost.

8. Asset Impairments (Exelon and Generation)

The Registrants evaluate the carrying value of long-lived assets or 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. The Registrants determine if long-lived assets or 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. The fair value

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

Note 8 — Asset Impairments

analysis is primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could potentially result in material future impairments of the Registrant's long-lived assets.

Antelope Valley Solar Facility

Generation's Antelope Valley, a 242 MW solar facility in Lancaster, CA, sells all of its output to PG&E through a PPA. As of March 31, 2020, Generation had approximately \$717 million of net long-lived assets related to Antelope Valley. As a result of the PG&E bankruptcy filing in the first quarter of 2019, Generation completed a comprehensive review of Antelope Valley's estimated undiscounted future cash flows and no impairment charge was recorded. Significant changes in assumptions such as the likelihood of the PPA being rejected as part of the bankruptcy proceedings could potentially result in future impairments of Antelope Valley's net long-lived assets, which could be material.

Antelope Valley is a wholly owned indirect subsidiary of EGR IV, which had approximately \$1,865 million of additional net long-lived assets as of March 31, 2020. EGR IV is a wholly owned indirect subsidiary of Exelon and Generation and includes Generation's interest in EGRP and other projects with non-controlling interests. To date, there have been no indicators to suggest that the carrying amount of other net long-lived assets of EGR IV may not be recoverable.

Generation will continue to monitor the bankruptcy proceedings for any changes in circumstances that may indicate the carrying amount of the net long-lived assets of Antelope Valley or other long-lived assets of EGR IV may not be recoverable.

See Note 12 - Debt and Credit Agreements for additional information on the PG&E bankruptcy.

New England Asset Group

During the first quarter of 2018, Mystic Unit 9 did not clear in the ISO-NE capacity auction for the 2021 - 2022 planning year. On March 29, 2018, Generation notified ISO-NE of the early retirement of its Mystic Generating Station's Units 7, 8, 9 and the Mystic Jet Unit (Mystic Generating Station assets) absent regulatory reforms. These events suggested that the carrying value of its New England asset group may be impaired. In the second quarter of 2018, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and no impairment charge was required. Generation continues to monitor developments in the region that would indicate a potential triggering event for impairment and continues to look for solutions that appropriately compensate both Mystic 8 and 9 and the Everett Marine Terminal for their contributions to the region. Further developments such as the failure of ISO-NE to adopt long-term solutions for reliability and fuel security could potentially result in material future impairments of the New England asset group. See Note 6 - Early Plant Retirements for additional information.

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, 2020								
	Exelon^(a)	Generation^(a)	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	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	<u>(345.9)%</u>	<u>71.1%</u>	<u>17.6%</u>	<u>9.7%</u>	<u>18.5%</u>	<u>9.2%</u>	<u>8.8%</u>	<u>13.5%</u>	<u>7.1%</u>

(a) 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. At the consolidated level, positive percentages represent income tax expense.

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

Note 9 — Income Taxes

	Three Months Ended March 31, 2019								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	3.9	3.1	8.2	1.0	6.3	4.7	2.1	6.5	6.7
Qualified NDT fund income	7.2	14.2	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.5)	(0.9)	(0.2)	—	(0.1)	(0.2)	(0.1)	(0.2)	(0.3)
Plant basis differences	(1.4)	—	(0.5)	(6.7)	(0.9)	(1.7)	(2.0)	(0.7)	(2.3)
Production tax credits and other credits	(0.8)	(1.5)	—	—	—	—	—	—	—
Noncontrolling interests	(0.6)	(1.1)	—	—	—	—	—	—	—
Excess deferred tax amortization	(4.7)	—	(8.5)	(2.5)	(7.9)	(19.4)	(17.9)	(15.6)	(23.9)
Other	0.1	(0.5)	0.3	0.2	—	(0.3)	0.4	0.7	(1.2)
Effective income tax rate	<u>24.2%</u>	<u>34.3%</u>	<u>20.3%</u>	<u>13.0%</u>	<u>18.4%</u>	<u>4.1%</u>	<u>3.5%</u>	<u>11.7%</u>	<u>—%</u>

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

Note 9 — Income Taxes

Accounting for Uncertainty in Income Taxes

Exelon, Generation, PHI and ACE have the following unrecognized tax benefits as of March 31, 2020 and December 31, 2019. ComEd, PECO, BGE, Pepco and DPL's amounts are not material.

	<u>Exelon</u>	<u>Generation</u>	<u>PHI</u>	<u>ACE</u>
March 31, 2020	\$ 98	\$ 32	\$ 49	\$ 14
December 31, 2019	507	441	48	14

Exelon's and Generation's unrecognized federal and state tax benefits decreased in the first quarter of 2020 by approximately \$411 million due to the settlement of a federal refund claim with IRS Appeals. The recognition of these tax benefits resulted in an increase to Exelon's and Generation's net income of \$76 million and \$73 million, respectively, for the quarter ended March 31, 2020, reflecting a decrease to Exelon's and Generation's income tax expense of \$67 million.

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

Settlement of Income Tax Audits, Refund Claims, and Litigation

The following table represents Exelon's, PHI's and ACE's unrecognized federal and state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, refund claims, and the outcomes of pending court cases as of March 31, 2020. Generation's, ComEd's, PECO's, BGE's, Pepco's and DPL's amounts are not material.

<u>Exelon</u>	<u>PHI</u>	<u>ACE^(a)</u>
\$ 14	\$ 14	\$ 14

(a) The unrecognized tax benefit related to ACE, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Other Income Tax Matters

State Income Tax Law Changes

On June 5, 2019, the Governor of Illinois signed a tax bill which would increase the Illinois corporate income tax rate from 9.50% to 10.49% effective for tax years beginning on or after January 1, 2021. The tax rate is contingent upon ratification of state constitutional amendments in November 2020. The effect of the rate change will be recognized in the period in which the new legislation is enacted. Exelon, Generation and ComEd do not expect a material impact to their financial statements as a result of the rate change.

10. Retirement Benefits (All Registrants)

Defined Benefit Pension and OPEB

During the first quarter of 2020, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2020. This valuation resulted in an increase to the pension and OPEB obligations of \$8 million and \$31 million, respectively. Additionally, accumulated other comprehensive income increased by \$7 million (after-tax) and regulatory assets and liabilities increased by \$19 million and decreased by \$10 million, respectively.

The majority of the 2020 pension benefit cost for Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 3.34%. The majority of the 2020 OPEB cost is calculated using an expected long-term rate of return on plan assets of 6.69% for funded plans and a discount rate of 3.31%.

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

Note 10 — Retirement Benefits

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, 2020 and 2019.

	Pension Benefits Three Months Ended March 31,		OPEB Three Months Ended March 31,	
	2020	2019	2020	2019
Components of net periodic benefit cost:				
Service cost	\$ 97	\$ 89	\$ 23	\$ 24
Interest cost	189	221	38	47
Expected return on assets	(318)	(307)	(41)	(38)
Amortization of:				
Prior service cost (benefit)	1	—	(31)	(45)
Actuarial loss	128	104	12	11
Net periodic benefit cost	<u>\$ 97</u>	<u>\$ 107</u>	<u>\$ 1</u>	<u>\$ (1)</u>

The amounts below represent the Registrants' allocated pension and OPEB plan 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,	
	2020	2019
Exelon	\$ 98	\$ 106
Generation	27	31
ComEd	28	24
PECO	1	2
BGE	16	16
PHI	17	23
Pepco	3	6
DPL	1	4
ACE	3	4

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

Note 10 — Retirement Benefits

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 during the three months ended March 31, 2020 and 2019, respectively.

Savings Plan Matching Contributions	Three Months Ended March 31,	
	2020	2019
Exelon	\$ 33	\$ 31
Generation	13	13
ComEd	7	7
PECO	3	2
BGE	2	2
PHI	3	4
Pepco	1	1
DPL	1	1
ACE	—	1

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 derivative settles 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 referencing 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 that 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.

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

Note 11 — Derivative Financial Instruments

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’ 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 ^(b)	Gas	NPNS	Fixed price contracts to cover about 20% 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 Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability ^(c)	Fixed price contracts through full requirements contracts. Exchange traded future contracts for 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 2 - Regulatory Matters for additional information.

(b) As part of its hedging program, PECO enters into electric supply procurement contracts that do not meet the definition of a derivative instrument.

(c) The fair value of the DPL economic hedge is not material as of March 31, 2020 and December 31, 2019 and is not presented in the fair value tables below.

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

Note 11 — Derivative Financial Instruments

The following table provides a summary of the derivative fair value balances recorded by Exelon, Generation and ComEd as of March 31, 2020 and December 31, 2019:

Derivatives	Exelon		Generation				ComEd
	Total Derivatives	Economic Hedges	Proprietary Trading	Collateral (a)(b)	Netting (a)	Subtotal	Economic Hedges
Mark-to-market derivative assets (current assets)	\$ 649	\$ 4,010	\$ 63	\$ 277	\$(3,701)	\$ 649	\$ —
Mark-to-market derivative assets (noncurrent assets)	625	1,878	23	112	(1,388)	625	—
Total mark-to-market derivative assets	1,274	5,888	86	389	(5,089)	1,274	—
Mark-to-market derivative liabilities (current liabilities)	(252)	(4,219)	(37)	339	3,701	(216)	(36)
Mark-to-market derivative liabilities (noncurrent liabilities)	(416)	(1,676)	(11)	161	1,388	(138)	(278)
Total mark-to-market derivative liabilities	(668)	(5,895)	(48)	500	5,089	(354)	(314)
Total mark-to-market derivative net assets (liabilities)	\$ 606	\$ (7)	\$ 38	\$ 889	\$ —	\$ 920	\$ (314)

Description	Exelon		Generation				ComEd
	Total Derivatives	Economic Hedges	Proprietary Trading	Collateral (a)(b)	Netting (a)	Subtotal	Economic Hedges
Mark-to-market derivative assets (current assets)	\$ 675	\$ 3,506	\$ 72	\$ 287	\$(3,190)	\$ 675	\$ —
Mark-to-market derivative assets (noncurrent assets)	508	1,238	25	122	(877)	508	—
Total mark-to-market derivative assets	1,183	4,744	97	409	(4,067)	1,183	—
Mark-to-market derivative liabilities (current liabilities)	(236)	(3,713)	(38)	357	3,190	(204)	(32)
Mark-to-market derivative liabilities (noncurrent liabilities)	(380)	(1,140)	(11)	163	877	(111)	(269)
Total mark-to-market derivative liabilities	(616)	(4,853)	(49)	520	4,067	(315)	(301)
Total mark-to-market derivative net assets (liabilities)	\$ 567	\$ (109)	\$ 48	\$ 929	\$ —	\$ 868	\$ (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 immaterial and not reflected in the table above.
- (b) Of the collateral posted/(received), \$644 million and \$511 million represents variation margin on the exchanges at March 31, 2020 and December 31, 2019 respectively.

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

Note 11 — Derivative Financial Instruments

Economic Hedges (Commodity Price Risk)

Generation. For the three months ended March 31, 2020 and 2019, 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,	
	2020	2019
	Gain (Loss)	
Operating revenues	\$ 175	\$ (50)
Purchased power and fuel	(47)	30
Total Exelon and Generation	\$ 128	\$ (20)

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, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York and ERCOT reportable segments is 89%-92% and 70%-73% for 2020 and 2021, respectively.

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, 2020 and 2019, net pre-tax commodity mark-to-market gains (losses) for Exelon and Generation were not material. The Utility Registrants do not execute derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon and Generation)

Exelon and Generation utilize interest rate swaps, which are treated as economic hedges, to manage their interest rate exposure. On July 1, 2018, Exelon de-designated its fair value hedges related to interest rate risk and Generation de-designated its cash flow hedges related to interest rate risk. The notional amounts were \$1,268 million and \$1,269 million at March 31, 2020 and December 31, 2019, respectively, for Exelon and \$568 million and \$569 million at March 31, 2020 and December 31, 2019, respectively, for Generation.

Generation utilizes foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, which are treated as economic hedges. The notional amounts were \$144 million and \$231 million at March 31, 2020 and December 31, 2019, respectively.

The mark-to-market derivative assets and liabilities as of March 31, 2020 and December 31, 2019 and the mark-to-market gains and losses for the three months ended March 31, 2020 and 2019 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

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

Note 11 — Derivative Financial Instruments

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.

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, 2020. 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 figures 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, 2020	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	\$ 915	\$ 22	\$ 893	—	\$ —
Non-investment grade	60	49	11		
No external ratings					
Internally rated — investment grade	228	1	227		
Internally rated — non- investment grade	157	22	135		
Total	\$ 1,360	\$ 94	\$ 1,266	—	\$ —

Net Credit Exposure by Type of Counterparty	As of March 31, 2020
Financial institutions	\$ 18
Investor-owned utilities, marketers, power producers	983
Energy cooperatives and municipalities	224
Other	41
Total	\$ 1,266

(a) As of March 31, 2020, credit collateral held from counterparties where Generation had credit exposure included \$29 million of cash and \$65 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, 2020, the Utility Registrants' counterparty credit risk with suppliers was immaterial.

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

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

Note 11 — Derivative Financial Instruments

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.

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, 2020	December 31, 2019
Gross fair value of derivative contracts containing this feature ^(a)	\$ (1,002)	\$ (956)
Offsetting fair value of in-the-money contracts under master netting arrangements ^(b)	699	649
Net fair value of derivative contracts containing this feature ^(c)	<u>\$ (303)</u>	<u>\$ (307)</u>

(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 a Registrant 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, 2020 and December 31, 2019, 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, 2020	December 31, 2019
Cash collateral posted	\$ 977	\$ 982
Letters of credit posted	256	264
Cash collateral held	105	103
Letters of credit held	115	112
Additional collateral required in the event of a credit downgrade below investment grade	1,468	1,509

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, and DPL's credit rating. As of March 31, 2020, PECO, BGE, and DPL were not required to post collateral for any of these agreements. If PECO, BGE or DPL lost their investment grade

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

Note 11 — Derivative Financial Instruments

credit ratings as of March 31, 2020, they could have been required to post incremental collateral to its counterparties of \$33 million, \$34 million and \$12 million, respectively.

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, 2020 and December 31, 2019. PECO had no commercial paper borrowings as of both March 31, 2020 and December 31, 2019.

Commercial Paper Issuer	Outstanding Commercial Paper as of		Average Interest Rate on Commercial Paper Borrowings as of	
	March 31, 2020	December 31, 2019	March 31, 2020	December 31, 2019
Exelon ^(a)	\$ 979	\$ 870	2.91%	2.25%
Generation	595	320	2.01%	1.84%
ComEd	—	130	—%	2.38%
BGE	141	76	4.45%	2.46%
PHI ^(b)	108	208	4.25%	N/A
PEPCO	—	82	—%	2.56%
DPL	54	56	4.17%	2.02%
ACE	54	70	4.32%	2.43%

(a) Includes outstanding commercial paper at Exelon Corporate of \$135 million and \$136 million with average interest rates on commercial paper borrowings of 4.20% and 1.92% at March 31, 2020 and December 31, 2019, respectively.

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

On March 19, 2020, Generation borrowed \$1.5 billion on its revolving credit facility due to disruptions in the commercial paper markets as a result of COVID-19, which is recorded in Long-term debt on Exelon's and Generation's Consolidated Balance Sheet. The funds were used to refinance commercial paper. Generation repaid the \$1.5 billion borrowed on the revolving credit facility on April 3, 2020. As of March 31, 2020, the available capacity on Generation's revolving credit facility was \$2.4 billion. See Note 16— Debt and Credit Agreements of the Exelon 2019 Form 10-K for additional information on the Registrants' credit facilities.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for \$500 million. The loan agreement was renewed on March 19, 2020 and will expire on March 18, 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 Sheet within Short-Term borrowings.

On March 19, 2020, Generation entered into a term loan agreement for \$200 million. The loan agreement has an expiration of March 18, 2021. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.50% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Generation's Consolidated Balance Sheet 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 has an expiration of March 30, 2021. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.75% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Generation's Consolidated Balance Sheet within Short-term borrowings.

Credit Agreements

On April 24, 2020, Exelon Corporate entered into a credit agreement establishing a \$550 million 364-day revolving credit facility at a variable interest rate of LIBOR plus 1.75%. This facility will be used by Exelon as an additional source of short-term liquidity over the next 12 months.

Long-Term Debt

Issuance of Long-Term Debt

During the three months ended March 31, 2020, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing ^(a)	3.95%	August 31, 2020	\$ 2	Funding to install energy conservation measures for the Fort Meade project.
Generation	Energy Efficiency Project Financing ^(a)	2.53%	April 30, 2021	1	Funding to install energy conservation measures for the Fort AP Hill project.
ComEd	First Mortgage Bonds, Series 129	3.00%	March 1, 2050	650	Repay a portion of outstanding commercial paper obligations and to fund general corporate purposes.
ComEd	First Mortgage Bonds, Series 128	2.20%	March 1, 2030	350	Repay a portion of outstanding commercial paper obligations and fund other general corporate purposes.
Pepco ^(b)	First Mortgage Bonds	2.53%	February 25, 2030	150	Repay existing indebtedness 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 February 25, 2020, Pepco entered into a purchase agreement of First Mortgage Bonds for \$150 million at 3.28% due on September 23, 2050. The closing date of the issuance is expected to occur in September 2020.

On April 1, 2020, Exelon Corporate issued notes for \$1.25 billion at 4.05%, which are due in 2030 and notes for \$750 million at 4.70%, which are due in 2050. A portion of the net proceeds from the sale of these notes, together with available cash balances, will be used to repay \$900 million of Exelon Corporate notes maturing in June of 2020. The remainder of the net proceeds will be used for general corporate purposes.

Debt Covenants

As of March 31, 2020, the Registrants are in compliance with debt covenants, except for Antelope Valley's ongoing nonrecourse debt event of default as discussed below.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing. 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.

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to \$646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in 2014. The loan will mature on January 5, 2037. As of March 31, 2020, approximately \$479 million was outstanding. In addition, Generation has issued letters of credit to support its equity investment in the project. As of March 31, 2020, Generation had \$37 million in letters of

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

Note 12 — Debt and Credit Agreements

credit outstanding related to the project. In 2017, Generation's interests in Antelope Valley were also contributed to and are pledged as collateral for the EGR IV financing structure referenced below.

Antelope Valley sells all of its output to PG&E through a PPA. On January 29, 2019, PG&E filed for protection under Chapter 11 of the U.S. Bankruptcy Code, which created an event of default for Antelope Valley's nonrecourse debt that provides the lender with a right to accelerate amounts outstanding under the loan such that they would become immediately due and payable. As a result of the ongoing event of default and the absence of a waiver from the lender foregoing their acceleration rights, the debt was reclassified as current in Exelon's and Generation's Consolidated Balance Sheets in the first quarter of 2019 and continues to be classified as current as of March 31, 2020. Further, distributions from Antelope Valley to EGR IV are currently suspended.

ExGen Renewables IV. In November 2017, EGR IV, an indirect subsidiary of Exelon and Generation, entered into an \$850 million nonrecourse senior secured term loan credit facility agreement. Generation's interests in EGRP, Antelope Valley, SolGen, and Albany Green Energy were all contributed to and are pledged as collateral for this financing. The loan is scheduled to mature on November 28, 2024. As of March 31, 2020, \$796 million was outstanding.

Although Antelope Valley's debt is in default, it is nonrecourse to EGR IV. However, if in the future Antelope Valley were to file for bankruptcy protection as a result of events culminating from PG&E's bankruptcy proceedings this would represent an event of default for EGR IV's debt that would provide the lender with an opportunity to accelerate EGR IV's debt.

See Note 16— Debt and Credit Agreements of the Exelon 2019 Form 10-K for additional information on nonrecourse debt.

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.

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

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, 2020 and December 31, 2019. 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, 2020				December 31, 2019			
	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	\$ 37,656	\$ 36,908	\$ 2,556	\$ 39,464	\$ 36,039	\$ 37,453	\$ 2,580	\$ 40,033
Generation	8,449	7,034	1,330	8,364	7,974	7,304	1,366	8,670
ComEd	9,478	10,483	—	10,483	8,491	9,848	—	9,848
PECO	3,406	3,762	50	3,812	3,405	3,868	50	3,918
BGE	3,271	3,572	—	3,572	3,270	3,649	—	3,649
PHI	6,708	5,602	1,176	6,778	6,563	5,902	1,164	7,066
Pepco	3,015	3,009	483	3,492	2,864	3,198	388	3,586
DPL	1,575	1,334	271	1,605	1,567	1,408	311	1,719
ACE	1,325	991	421	1,412	1,327	1,026	464	1,490
Long-Term Debt to Financing Trusts^(a)								
Exelon	\$ 390	\$ —	\$ 387	\$ 387	\$ 390	\$ —	\$ 428	\$ 428
ComEd	205	—	204	204	205	—	227	227
PECO	184	—	183	183	184	—	201	201
SNF Obligation								
Exelon	\$ 1,204	\$ 723	\$ —	\$ 723	\$ 1,199	\$ 1,055	\$ —	\$ 1,055
Generation	1,204	723	—	723	1,199	1,055	—	1,055

(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, 2020 and December 31, 2019:

Exelon and Generation

As of March 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)	\$ 1,399	\$ —	\$ —	\$ —	\$ 1,399	\$ 591	\$ —	\$ —	\$ —	\$ 591
NDT fund investments										
Cash equivalents ^(b)	373	79	—	—	452	373	79	—	—	452
Equities	2,603	1,377	—	1,080	5,060	2,603	1,377	—	1,080	5,060
Fixed income										
Corporate debt	—	1,412	258	—	1,670	—	1,412	258	—	1,670
U.S. Treasury and agencies	1,723	141	—	—	1,864	1,723	141	—	—	1,864
Foreign governments	—	37	—	—	37	—	37	—	—	37
State and municipal debt	—	87	—	—	87	—	87	—	—	87
Other ^(c)	—	26	—	872	898	—	26	—	872	898
Fixed income subtotal	1,723	1,703	258	872	4,556	1,723	1,703	258	872	4,556
Private credit	—	—	240	546	786	—	—	240	546	786
Private equity	—	—	—	444	444	—	—	—	444	444
Real estate	—	—	—	636	636	—	—	—	636	636
NDT fund investments subtotal ^(d)	4,699	3,159	498	3,578	11,934	4,699	3,159	498	3,578	11,934
Rabbi trust investments										
Cash equivalents	51	—	—	—	51	4	—	—	—	4
Mutual funds	75	—	—	—	75	23	—	—	—	23
Fixed income	—	11	—	—	11	—	—	—	—	—
Life insurance contracts	—	72	42	—	114	—	22	—	—	22
Rabbi trust investments subtotal	126	83	42	—	251	27	22	—	—	49
Commodity derivative assets										
Economic hedges	714	3,135	2,039	—	5,888	714	3,135	2,039	—	5,888
Proprietary trading	—	29	57	—	86	—	29	57	—	86
Effect of netting and allocation of collateral ^{(e)(f)}	(868)	(2,770)	(1,062)	—	(4,700)	(868)	(2,770)	(1,062)	—	(4,700)
Commodity derivative assets subtotal	(154)	394	1,034	—	1,274	(154)	394	1,034	—	1,274
Total assets	6,070	3,636	1,574	3,578	14,858	5,163	3,575	1,532	3,578	13,848

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, 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
Liabilities										
Commodity derivative liabilities										
Economic hedges	(990)	(3,476)	(1,743)	—	(6,209)	(990)	(3,476)	(1,429)	—	(5,895)
Proprietary trading	—	(28)	(20)	—	(48)	—	(28)	(20)	—	(48)
Effect of netting and allocation of collateral ⁽⁶⁾⁽⁷⁾	994	3,318	1,277	—	5,589	994	3,318	1,277	—	5,589
Commodity derivative liabilities subtotal	4	(186)	(486)	—	(668)	4	(186)	(172)	—	(354)
Deferred compensation obligation	—	(126)	—	—	(126)	—	(34)	—	—	(34)
Total liabilities	4	(312)	(486)	—	(794)	4	(220)	(172)	—	(388)
Total net assets	\$ 6,074	\$ 3,324	\$ 1,088	\$ 3,578	\$ 14,064	\$ 5,167	\$ 3,355	\$ 1,360	\$ 3,578	\$ 13,460

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, 2019	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)	\$ 639	\$ —	\$ —	\$ —	\$ 639	\$ 214	\$ —	\$ —	\$ —	\$ 214
NDT fund investments										
Cash equivalents ^(b)	365	87	—	—	452	365	87	—	—	452
Equities	3,353	1,753	—	1,388	6,494	3,353	1,753	—	1,388	6,494
Fixed income										
Corporate debt	—	1,469	257	—	1,726	—	1,469	257	—	1,726
U.S. Treasury and agencies	1,808	131	—	—	1,939	1,808	131	—	—	1,939
Foreign governments	—	42	—	—	42	—	42	—	—	42
State and municipal debt	—	90	—	—	90	—	90	—	—	90
Other ^(c)	—	33	—	953	986	—	33	—	953	986
Fixed income subtotal	1,808	1,765	257	953	4,783	1,808	1,765	257	953	4,783
Private credit	—	—	254	508	762	—	—	254	508	762
Private equity	—	—	—	402	402	—	—	—	402	402
Real estate	—	—	—	607	607	—	—	—	607	607
NDT fund investments subtotal ^(d)	5,526	3,605	511	3,858	13,500	5,526	3,605	511	3,858	13,500
Rabbi trust investments										
Cash equivalents	50	—	—	—	50	4	—	—	—	4
Mutual funds	81	—	—	—	81	25	—	—	—	25
Fixed income	—	12	—	—	12	—	—	—	—	—
Life insurance contracts	—	78	41	—	119	—	25	—	—	25
Rabbi trust investments subtotal	131	90	41	—	262	29	25	—	—	54
Commodity derivative assets										
Economic hedges	768	2,491	1,485	—	4,744	768	2,491	1,485	—	4,744
Proprietary trading	—	37	60	—	97	—	37	60	—	97
Effect of netting and allocation of collateral ^{(e)(f)}	(908)	(2,162)	(588)	—	(3,658)	(908)	(2,162)	(588)	—	(3,658)
Commodity derivative assets subtotal	(140)	366	957	—	1,183	(140)	366	957	—	1,183
Total assets	6,156	4,061	1,509	3,858	15,584	5,629	3,996	1,468	3,858	14,951

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, 2019	Exelon					Generation				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Liabilities										
Commodity derivative liabilities										
Economic hedges	(1,071)	(2,855)	(1,228)	—	(5,154)	(1,071)	(2,855)	(927)	—	(4,853)
Proprietary trading	—	(34)	(15)	—	(49)	—	(34)	(15)	—	(49)
Effect of netting and allocation of collateral ^{(6)(f)}	1,071	2,714	802	—	4,587	1,071	2,714	802	—	4,587
Commodity derivative liabilities subtotal	—	(175)	(441)	—	(616)	—	(175)	(140)	—	(315)
Deferred compensation obligation	—	(147)	—	—	(147)	—	(41)	—	—	(41)
Total liabilities	—	(322)	(441)	—	(763)	—	(216)	(140)	—	(356)
Total net assets	\$ 6,156	\$ 3,739	\$ 1,068	\$ 3,858	\$ 14,821	\$ 5,629	\$ 3,780	\$ 1,328	\$ 3,858	\$ 14,595

- (a) Exelon excludes cash of \$483 million and \$373 million at March 31, 2020 and December 31, 2019, respectively, and restricted cash of \$110 million at both March 31, 2020 and December 31, 2019, and includes long-term restricted cash of \$121 million and \$177 million at March 31, 2020 and December 31, 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Generation excludes cash of \$317 million and \$177 million at March 31, 2020 and December 31, 2019, respectively, and restricted cash of \$63 million and \$58 million at March 31, 2020 and December 31, 2019, respectively.
- (b) Includes \$78 million and \$90 million of cash received from outstanding repurchase agreements at March 31, 2020 and December 31, 2019, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.
- (c) Includes a derivative liability of \$2 million and a derivative asset of \$2 million, which have total notional amounts of \$826 million and \$724 million at March 31, 2020 and December 31, 2019, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of Exelon and Generation's exposure to credit or market loss.
- (d) Excludes net liabilities of \$110 million and \$147 million at March 31, 2020 and December 31, 2019, 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.
- (e) Collateral posted/(received) from counterparties totaled \$126 million, \$548 million and \$215 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of March 31, 2020. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled \$163 million, \$551 million and \$214 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2019.
- (f) Of the collateral posted/(received), \$644 million and \$511 million represents variation margin on the exchanges as of March 31, 2020 and December 31, 2019, respectively.

As of March 31, 2020, Exelon and Generation have outstanding commitments to invest in fixed income, private credit, private equity and real estate investments of approximately \$80 million, \$131 million, \$338 million, and \$428 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 \$76 million and \$66 million as of March 31, 2020, respectively. Changes in fair value, cumulative adjustments and impairments were not material for the three months ended March 31, 2020.

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, 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)	\$ 729	\$ —	\$ —	\$ 729	\$ 8	\$ —	\$ —	\$ 8	\$ —	\$ —	\$ —	\$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	8	—	—	8
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	1	1
Rabbi trust investments subtotal	—	—	—	—	7	10	—	17	8	—	1	9
Total assets	729	—	—	729	15	10	—	25	8	—	1	9
Liabilities												
Deferred compensation obligation	—	(7)	—	(7)	—	(8)	—	(8)	—	(5)	—	(5)
Mark-to-market derivative liabilities ^(b)	—	—	(314)	(314)	—	—	—	—	—	—	—	—
Total liabilities	—	(7)	(314)	(321)	—	(8)	—	(8)	—	(5)	—	(5)
Total net assets (liabilities)	\$ 729	\$ (7)	\$ (314)	\$ 408	\$ 15	\$ 2	\$ —	\$ 17	\$ 8	\$ (5)	\$ 1	\$ 4

As of December 31, 2019	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)	\$ 280	\$ —	\$ —	\$ 280	\$ 15	\$ —	\$ —	\$ 15	\$ —	\$ —	\$ —	\$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	8	—	—	8	8	—	—	8
Life insurance contracts	—	—	—	—	—	11	—	11	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	8	11	—	19	8	—	—	8
Total assets	280	—	—	280	23	11	—	34	8	—	—	8
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)	\$ 280	\$ (8)	\$ (301)	\$ (29)	\$ 23	\$ 2	\$ —	\$ 25	\$ 8	\$ (5)	\$ —	\$ 3

(a) ComEd excludes cash of \$67 million and \$90 million at March 31, 2020 and December 31, 2019, respectively, and restricted cash of \$38 million and \$33 million at March 31, 2020 and December 31, 2019, respectively, and includes long-term restricted cash of \$108 million and \$163 million at March 31, 2020 and December 31, 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of \$30 million and \$12 million at March 31, 2020 and December 31, 2019, respectively. BGE excludes cash of \$11 million and \$24 million at March 31, 2020 and December 31, 2019, respectively, and restricted cash of \$1 million at both March 31, 2020 and December 31, 2019.

(b) The Level 3 balance consists of the current and noncurrent liability of \$36 million and \$278 million, respectively, at March 31, 2020, and \$32 million and \$269 million, respectively, at December 31, 2019, 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, 2020				As of December 31, 2019			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents ^(a)	\$ 63	\$ —	\$ —	\$ 63	\$ 124	\$ —	\$ —	\$ 124
Rabbi trust investments								
Cash equivalents	44	—	—	44	44	—	—	44
Mutual funds	13	—	—	13	14	—	—	14
Fixed income	—	11	—	11	—	12	—	12
Life insurance contracts	—	25	42	67	—	24	41	65
Rabbi trust investments subtotal	57	36	42	135	58	36	41	135
Total assets	120	36	42	198	182	36	41	259
Liabilities								
Deferred compensation obligation	—	(16)	—	(16)	—	(19)	—	(19)
Total liabilities	—	(16)	—	(16)	—	(19)	—	(19)
Total net assets	\$ 120	\$ 20	\$ 42	\$ 182	\$ 182	\$ 17	\$ 41	\$ 240

As of March 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)	\$ 34	\$ —	\$ —	\$ 34	\$ —	\$ —	\$ —	\$ —	\$ 15	\$ —	\$ —	\$ 15
Rabbi trust investments												
Cash equivalents	44	—	—	44	—	—	—	—	—	—	—	—
Fixed income	—	1	—	1	—	—	—	—	—	—	—	—
Life insurance contracts	—	25	42	67	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	44	26	42	112	—	—	—	—	—	—	—	—
Total assets	78	26	42	146	—	—	—	—	15	—	—	15
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets	\$ 78	\$ 24	\$ 42	\$ 144	\$ —	\$ —	\$ —	\$ —	\$ 15	\$ —	\$ —	\$ 15

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, 2019	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)	\$ 34	\$ —	\$ —	\$ 34	\$ —	\$ —	\$ —	\$ —	\$ 16	\$ —	\$ —	\$ 16
Rabbi trust investments												
Cash equivalents	43	—	—	43	—	—	—	—	—	—	—	—
Fixed income	—	2	—	2	—	—	—	—	—	—	—	—
Life insurance contracts	—	24	41	65	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	43	26	41	110	—	—	—	—	—	—	—	—
Total assets	77	26	41	144	—	—	—	—	16	—	—	16
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets (liabilities)	\$ 77	\$ 24	\$ 41	\$ 142	\$ —	\$ —	\$ —	\$ —	\$ 16	\$ —	\$ —	\$ 16

(a) PHI excludes cash of \$35 million and \$57 million at March 31, 2020 and December 31, 2019, respectively, and includes long-term restricted cash of \$12 million and \$14 million at March 31, 2020 and December 31, 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Pepco excludes cash of \$17 million and \$29 million at March 31, 2020 and December 31, 2019, respectively. DPL excludes cash of \$6 million and \$13 million at March 31, 2020 and December 31, 2019, respectively. ACE excludes cash of \$8 million and \$12 million at March 31, 2020 and December 31, 2019, respectively, and includes long-term restricted cash of \$12 million and \$14 million at March 31, 2020 and December 31, 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets.

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

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, 2020 and 2019:

Three Months Ended March 31, 2020	Exelon		Generation		ComEd	PHI and Pepco	
	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
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	<u>\$ 1,088</u>	<u>\$ 498</u>	<u>\$ 862</u>	<u>\$ 1,360</u>	<u>\$ (314)</u>	<u>\$ 42</u>	<u>\$ —</u>
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	\$ —

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, 2019	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, 2018	\$ 907	\$ 543	\$ 575	\$ 1,118	\$ (249)	\$ 38	\$ —	
Total realized / unrealized gains (losses)								
Included in net income	(228)	2	(231) ^(a)	(229)	—	1	—	
Included in noncurrent payables to affiliates	—	11	—	11	—	—	(11)	
Included in regulatory assets	20	—	—	—	9 ^(b)	—	11	
Change in collateral	81	—	81	81	—	—	—	
Purchases, sales, issuances and settlements								
Purchases	58	1	57	58	—	—	—	
Sales	—	—	—	—	—	—	—	
Settlements	(17)	(17)	—	(17)	—	—	—	
Transfers into Level 3	—	—	— ^(c)	—	—	—	—	
Transfers out of Level 3	17	—	17 ^(c)	17	—	—	—	
Balance as of March 31, 2019	\$ 838	\$ 540	\$ 499	\$ 1,039	\$ (240)	\$ 39	\$ —	
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, 2019	\$ (148)	\$ 2	\$ (151)	\$ (149)	\$ —	\$ 1	\$ —	

- (a) Includes a reduction for the reclassification of \$177 million and \$80 million of realized losses due to the settlement of derivative contracts for the three months ended March 31, 2020 and 2019, respectively.
- (b) Includes \$23 million of decreases 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. Includes \$14 million of decreases in fair value and an increase for realized losses due to settlements of \$5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2019.
- (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, 2020 and 2019:

	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 realized gains (losses) for the three months ended March 31, 2020	\$ 72	\$ (62)	\$ 1	\$ (1)	\$ 72	\$ (62)	\$ (1)	\$ 1
Total unrealized gains (losses) 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

	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 realized (losses) gains for the three months ended March 31, 2019	\$ (128)	\$ (103)	\$ 1	\$ 2	\$ (128)	\$ (103)	\$ 2	\$ 1
Total unrealized (losses) gains for the three months ended March 31, 2019	(91)	(60)	1	2	(91)	(60)	2	1

Valuation Techniques Used to Determine Fair Value

Exelon's valuation techniques used to measure the fair value of the assets and liabilities shown in the tables below are in accordance with the policies discussed in Note 17 — Fair Value of Financial Assets and Liabilities of the Exelon 2019 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.

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

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, 2020	Fair Value at December 31, 2019	Valuation Technique	Unobservable Input	2020 Range & Arithmetic Average		2019 Range & Arithmetic Average			
Mark-to-market derivatives — Economic Hedges (Exelon and Generation) ^{(a)(b)}	\$ 610	\$ 558	Discounted Cash Flow	Forward power price	\$6	- \$136	\$27	\$9	- \$180	\$29
				Forward gas price	\$1.02	- \$8.10	\$2.43	\$0.83	- \$10.72	\$2.55
				Option Model	Volatility percentage	8%	- 304%	70%	8%	- 236%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation) ^{(a)(b)}	\$ 37	\$ 45	Discounted Cash Flow	Forward power price	\$15	- \$136	\$31	\$25	- \$180	\$33
				Mark-to-market derivatives (Exelon and ComEd)	\$ (314)	\$ (301)	Discounted Cash Flow	Forward heat rate ^(c)	9x	- 10x
				Marketability reserve	3%	- 7%	5.11%	3%	- 7%	4.95%
				Renewable factor	90%	- 122%	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 \$215 million and \$214 million as of March 31, 2020 and December 31, 2019, 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.

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 18 of the Exelon 2019 Form 10-K.

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

Note 14 — Commitments and Contingencies

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, 2020:

<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)	95	75	62	8	5

(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 \$127 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, 2020, 27 MWs of new generation were developed and Exelon and Generation have incurred costs of \$122 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, 2020, representing commitments potentially triggered by future events were as follows:

	Total	Expiration within					2025 and beyond
		2020	2021	2022	2023	2024	
Exelon							
Letters of credit	\$ 1,464	\$ 1,080	\$ 384	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	849	698	151	—	—	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values ^(b)	27	1	2	4	3	12	5
Total commercial commitments	<u>\$ 2,718</u>	<u>\$ 1,779</u>	<u>\$ 537</u>	<u>\$ 4</u>	<u>\$ 3</u>	<u>\$ 12</u>	<u>\$ 383</u>
Generation							
Letters of credit	\$ 1,449	\$ 1,071	\$ 378	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	685	591	94	—	—	—	—
Total commercial commitments	<u>\$ 2,134</u>	<u>\$ 1,662</u>	<u>\$ 472</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>
ComEd							
Letters of credit	\$ 7	\$ 4	\$ 3	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	15	11	4	—	—	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	<u>\$ 222</u>	<u>\$ 15</u>	<u>\$ 7</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 200</u>
PECO							
Surety bonds ^(a)	\$ 9	\$ 8	\$ 1	\$ —	\$ —	\$ —	\$ —
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	<u>\$ 187</u>	<u>\$ 8</u>	<u>\$ 1</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 178</u>
BGE							
Letters of credit	\$ 2	\$ 2	\$ —	\$ —	\$ —	\$ —	\$ —
Surety bonds ^(a)	17	16	1	—	—	—	—
Total commercial commitments	<u>\$ 19</u>	<u>\$ 18</u>	<u>\$ 1</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>
PHI							
Surety bonds ^(a)	\$ 21	\$ 20	\$ 1	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	27	1	2	4	3	12	5
Total commercial commitments	<u>\$ 48</u>	<u>\$ 21</u>	<u>\$ 3</u>	<u>\$ 4</u>	<u>\$ 3</u>	<u>\$ 12</u>	<u>\$ 5</u>
Pepco							
Surety bonds ^(a)	\$ 14	\$ 14	\$ —	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	9	—	1	1	1	4	2
Total commercial commitments	<u>\$ 23</u>	<u>\$ 14</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 4</u>	<u>\$ 2</u>
DPL							
Surety bonds ^(a)	\$ 4	\$ 3	\$ 1	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	11	—	1	2	1	5	2
Total commercial commitments	<u>\$ 15</u>	<u>\$ 3</u>	<u>\$ 2</u>	<u>\$ 2</u>	<u>\$ 1</u>	<u>\$ 5</u>	<u>\$ 2</u>
ACE							
Surety bonds ^(a)	\$ 3	\$ 3	\$ —	\$ —	\$ —	\$ —	\$ —
Guaranteed lease residual values ^(b)	7	1	—	1	1	3	1
Total commercial commitments	<u>\$ 10</u>	<u>\$ 4</u>	<u>\$ —</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ 3</u>	<u>\$ 1</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 \$72 million guaranteed by Exelon and PHI, of which \$24 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 2025.
- 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 2022.
- 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 2021.
- 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, 2020 and December 31, 2019, 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, 2020		December 31, 2019	
	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	\$ 472	\$ 317	\$ 478	\$ 320
Generation	104	—	105	—
ComEd	301	300	304	303
PECO	19	17	19	17
BGE	2	—	2	—
PHI	46	—	48	—
Pepco	44	—	46	—
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 (ROD) Amendment for the selection of a final remedy. The ROD Amendment modified the remedy previously selected by EPA in its 2008 ROD. While the ROD required only that the radiological materials and other wastes at the site be capped, the ROD Amendment requires partial excavation of the radiological materials in addition to the previously selected capping remedy. The ROD Amendment 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 the 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Note 14 — Commitments and Contingencies

Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater Remedial Investigation (RI)/Feasibility Study (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 \$20 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. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately \$90 million from all PRPs. Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until August 31, 2020 so that settlement discussions can proceed. 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 and on October 4, 2019 released this document for review and comment by the public. The 45 day comment period ended on November 18, 2019 and a public meeting was held by Pepco on November 2, 2019. Pepco and Generation will proceed to develop 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 September 16, 2021.

DOEE will then prepare a Proposed Plan and issue a Record of Decision identifying any further response actions determined to be necessary, after considering public comment on the Proposed Plan. 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. DOEE asked Pepco, along with parties responsible for other sites along the river, to participate in a "Consultative Working Group" to provide input into the process for future remedial actions and to ensure proper coordination with the other river cleanup efforts currently underway, including cleanup of the river segment adjacent to the Benning Road site resulting from the Benning Road site RI/FS. In addition, the District of Columbia Council directed DOEE to form an official advisory committee made up of members of federal,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Note 14 — Commitments and Contingencies

state and local environmental regulators, community and environmental groups and various academic and technical experts to provide guidance and support to DOEE as the project progressed. This group, called the Anacostia Leadership Council, has met regularly since it was formed. Pepco has participated in the Consultative Working Group. 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 based on DOEE's stated position following a series of meetings attended by representatives from the Anacostia Leadership Council and the Consultative Working Group. On December 27, 2019, DOEE released for review and comment by the public a Focused Feasibility Study (FFS) and a Proposed Plan (PP). The FFS and PP will be the basis for the Interim ROD, which is expected to be completed in September 2020. The FFS and PP are consistent with the DOEE's stated position to follow an adaptive management approach which will allow several identified "hot spots" in the river to be addressed first while continuing to conduct studies and to monitor the river to evaluate improvements and determine potential future remediation plans. The adaptive management process chosen by DOEE is less intrusive, provides more long term environmental certainty, is less costly, and allows for site specific remediation plans already underway, including the plan for the Benning Road site to proceed to conclusion. Pepco concluded that incremental exposure remains reasonably possible, however 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. The Natural Resource Damages (NRD) assessment typically takes place following cleanup because cleanups sometimes also effectively restore affected natural resources. During the second quarter of 2018, Pepco became aware that the Trustees are in the beginning stages of this 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, 2020 and December 31, 2019, Exelon and Generation had recorded estimated liabilities of approximately \$82 million and \$83 million, respectively, in total for asbestos-related bodily injury claims. As of March 31, 2020, approximately \$27 million of this amount related to 268 open claims presented to Generation, while the remaining \$55 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.

City of Everett Tax Increment Financing Agreement (Exelon and Generation). On April 10, 2017, the City of Everett petitioned the Massachusetts Economic Assistance Coordinating Council (EACC) to revoke the 1999 tax increment financing agreement (TIF Agreement) relating to Mystic Units 8 and 9 on the grounds that the total investment in Mystic Units 8 and 9 materially deviates from the investment set forth in the TIF Agreement. On October 31, 2017, a three-member panel of the EACC conducted an administrative hearing on the City's petition. On November 30, 2017, the hearing panel issued a tentative decision denying the City's petition, finding that there was no material misrepresentation that would justify revocation of the TIF Agreement. On December 13, 2017, the tentative decision was adopted by the full EACC. On January 12, 2018, the City filed a complaint in Massachusetts Superior Court requesting, among other things, that the court set aside the EACC's decision, grant the City's request

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Note 14 — Commitments and Contingencies

to decertify the Project and the TIF Agreement, and award the City damages for alleged underpaid taxes over the period of the TIF Agreement. On January 8, 2020, the Massachusetts Superior Court affirmed the decision of the EACC denying the City's petition. The City had until March 9, 2020 to appeal the decision and did not. As a result, the decision is final and the case is resolved. It is reasonably possible that property taxes assessed in future periods, including those following the expiration of the current TIF Agreement in 2020, could be material to Generation's financial statements.

Subpoenas (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 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 U.S. Attorney's Office for the Northern District of Illinois requiring production of records of any communications with certain individuals and entities. On October 22, 2019, the SEC notified Exelon and ComEd that it has also opened an investigation into their lobbying activities. Exelon and ComEd have cooperated fully and intend to continue to cooperate fully and expeditiously with the U.S. Attorney's Office and the SEC. Exelon and ComEd cannot predict the outcome of the U.S. Attorney's Office or the SEC investigations. No loss contingency has been reflected in Exelon's and ComEd's consolidated financial statements as this contingency is neither probable nor reasonably estimable at this time. Management is currently unable to estimate a range of reasonably possible loss as these matters are subject to change.

Subsequent to Exelon announcing the receipt of the subpoenas, a putative class action lawsuit has been filed against Exelon and certain officers of Exelon and ComEd alleging misrepresentations or omissions by Exelon purporting to relate to matters that are the subject of the subpoenas and the SEC investigation. In addition, a derivative shareholder lawsuit has been filed against Exelon, its directors and certain officers alleging, among other things, a breach of fiduciary duties also purporting to relate to matters that are the subject of the subpoenas and the SEC investigation. Exelon believes that these claims lack merit and intends to defend against them, and though the costs or any loss associated with the lawsuits cannot be reasonably estimated at this time, Exelon does not believe that the lawsuits, either individually or collectively, will have a material adverse impact on Exelon's or ComEd's consolidated financial statements.

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, 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)

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, 2019	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items ^(a)	Foreign Currency Items	AOCI of Investments in Unconsolidated Affiliates ^(b)	Total
Beginning balance	\$ (2)	\$ (2,960)	\$ (33)	\$ —	\$ (2,995)
OCI before reclassifications	—	(38)	2	(1)	(37)
Amounts reclassified from AOCI	—	20	—	—	20
Net current-period OCI	—	(18)	2	(1)	(17)
Ending balance	<u>\$ (2)</u>	<u>\$ (2,978)</u>	<u>\$ (31)</u>	<u>\$ (1)</u>	<u>\$ (3,012)</u>

(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.

(b) All amounts are net of noncontrolling interests.

The following table presents income tax benefit (expense) allocated to each component of Exelon's other comprehensive income (loss):

	Three Months Ended March 31,	
	2020	2019
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	\$ 4	\$ 6
Actuarial loss reclassified to periodic benefit cost	(17)	(13)
Pension and non-pension postretirement benefit plans valuation adjustment	3	14

16. Variable Interest Entities (Exelon, Generation, PHI and ACE)

At March 31, 2020 and December 31, 2019, 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, 2020 and December 31, 2019. 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)
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	March 31, 2020				December 31, 2019			
	Exelon	Generation	PHI ^(a)	ACE	Exelon	Generation	PHI ^(a)	ACE
Cash and cash equivalents	\$ 51	\$ 51	\$ —	\$ —	\$ 163	\$ 163	\$ —	\$ —
Restricted cash and cash equivalents	84	81	3	3	88	85	3	3
Accounts receivable								
Customer	131	131	—	—	151	151	—	—
Other	44	44	—	—	39	39	—	—
Unamortized energy contract assets ^(b)	22	22	—	—	23	23	—	—
Inventories, net								
Materials and supplies	231	231	—	—	227	227	—	—
Other current assets	42	38	4	—	32	31	1	—
Total current assets	605	598	7	3	723	719	4	3
Property, plant and equipment, net ^(c)	6,017	6,017	—	—	6,022	6,022	—	—
Nuclear decommissioning trust funds	2,405	2,405	—	—	2,741	2,741	—	—
Unamortized energy contract assets ^(b)	264	264	—	—	250	250	—	—
Other noncurrent assets	71	56	15	12	89	73	16	14
Total noncurrent assets	8,757	8,742	15	12	9,102	9,086	16	14
Total assets	\$ 9,362	\$ 9,340	\$ 22	\$ 15	\$ 9,825	\$ 9,805	\$ 20	\$ 17
Long-term debt due within one year	\$ 543	\$ 519	\$ 24	\$ 20	\$ 544	\$ 523	\$ 21	\$ 20
Accounts payable	121	121	—	—	106	106	—	—
Accrued expenses	46	46	—	—	70	70	—	—
Unamortized energy contract liabilities	7	7	—	—	8	8	—	—
Other current liabilities	3	3	—	—	3	3	—	—
Total current liabilities	720	696	24	20	731	710	21	20
Long-term debt	502	483	19	16	527	504	23	21
Asset retirement obligations ^(d)	2,156	2,156	—	—	2,128	2,128	—	—
Unamortized energy contract liabilities	1	1	—	—	1	1	—	—
Other noncurrent liabilities	37	37	—	—	89	89	—	—
Total noncurrent liabilities	2,696	2,677	19	16	2,745	2,722	23	21
Total liabilities	\$ 3,416	\$ 3,373	\$ 43	\$ 36	\$ 3,476	\$ 3,432	\$ 44	\$ 41

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

(b) These are unrestricted assets to Exelon and Generation.

(c) Exelon's and Generation's balances include unrestricted assets of \$20 million as of March 31, 2020 and December 31, 2019.

(d) Exelon's and Generation's balances include liabilities with recourse of \$4 million and \$3 million as of March 31, 2020 and December 31, 2019, respectively.

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

As of March 31, 2020 and December 31, 2019, 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 Nuclear Operating Services Agreement (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 is a minority interest holder.	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 the third quarter of 2019. See Note 11— Asset Impairments of the Exelon 2019 Form 10-K for additional information.	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.

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 exercisable beginning on January 1, 2016 and thereafter until June 30, 2022. 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 will require approval by the NYPSC, the FERC and the NRC. The process and regulatory approvals could take one to two years or more to complete.

See Note 2 - Mergers, Acquisitions and Dispositions of the Exelon 2019 Form 10-K for additional information regarding the Put Option Agreement with EDF.

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 18 — Commitments and Contingencies of the Exelon 2019 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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 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. Generation provides operating and capital funding to the solar and wind entities for ongoing construction, operations and maintenance and there is limited recourse related 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 12— Debt and Credit Agreements for additional information on ExGen Renewables IV.

As of March 31, 2020 and December 31, 2019, 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 Transition 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 ACETF. 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, 2020 and December 31, 2019, 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.

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(Dollars in millions, except per share data, unless otherwise noted)

The following table presents summary information about Exelon's and Generation's significant unconsolidated VIE entities:

	March 31, 2020			December 31, 2019		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets ^(a)	\$ 695	\$ 431	\$ 1,126	\$ 636	\$ 443	\$ 1,079
Total liabilities ^(a)	158	223	381	33	227	260
Exelon's ownership interest in VIE ^(a)	—	183	183	—	191	191
Other ownership interests in VIE ^(a)	538	25	563	604	25	629

(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, 2020 and December 31, 2019.

As of March 31, 2020 and December 31, 2019, 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 the third quarter of 2019. See Note 11— Asset Impairments of the Exelon 2019 Form 10-K for additional information.	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.

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Note 17 — Supplemental Financial Information

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	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended March 31, 2020									
Operating lease income	\$ 5	\$ 3	\$ —	\$ —	\$ —	\$ 1	\$ —	\$ 1	\$ —
Variable lease income	69	69	—	—	—	—	—	—	—
Three Months Ended March 31, 2019									
Operating lease income	\$ 4	\$ 3	\$ —	\$ —	\$ —	\$ 1	\$ —	\$ 1	\$ —
Variable lease income	52	52	—	—	—	—	—	—	—
Taxes other than income taxes									
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
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
Three Months Ended March 31, 2019									
Utility taxes ^(a)	\$ 223	\$ 26	\$ 62	\$ 34	\$ 27	\$ 74	\$ 69	\$ 5	\$ —
Property	149	71	7	3	37	29	21	8	—
Payroll	65	33	7	4	4	7	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, 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	—	—	—	—	—	—	—	—

Three Months Ended March 31, 2019

Decommissioning-related activities:									
Net realized income on NDT funds ^(a)									
Regulatory agreement units	\$ 54	\$ 54	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —
Non-regulatory agreement units	54	54	—	—	—	—	—	—	—
Net unrealized losses on NDT funds									
Regulatory agreement units	379	379	—	—	—	—	—	—	—
Non-regulatory agreement units	280	280	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities ^(b)	(348)	(348)	—	—	—	—	—	—	—
Decommissioning-related activities	419	419	—	—	—	—	—	—	—
AFUDC — Equity	22	—	5	3	5	9	6	1	2
Non-service net periodic benefit cost	5	—	—	—	—	—	—	—	—

(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 9 — Asset Retirement Obligations of the Exelon 2019 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, 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	
Three Months Ended March 31, 2019										
Property, plant and equipment ^(a)	\$ 917	\$ 392	\$ 219	\$ 74	\$ 85	\$ 127	\$ 58	\$ 35	\$ 25	
Amortization of regulatory assets ^(a)	143	—	32	7	51	53	36	11	6	
Amortization of intangible assets, net ^(a)	15	13	—	—	—	—	—	—	—	
Nuclear fuel ^(c)	261	261	—	—	—	—	—	—	—	
ARO accretion ^(d)	124	123	—	—	—	—	—	—	—	
Total depreciation, amortization and accretion	\$ 1,460	\$ 789	\$ 251	\$ 81	\$ 136	\$ 180	\$ 94	\$ 46	\$ 31	

- (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, 2020									
Pension and non-pension postretirement benefit costs	\$ 98	\$ 27	\$ 28	\$ 1	\$ 15	\$ 17	\$ 3	\$ 1	\$ 3
Provision for uncollectible accounts	45	4	7	17	7	10	4	3	3
Other decommissioning-related activity ^(a)	128	128	—	—	—	—	—	—	—
Energy-related options ^(b)	6	6	—	—	—	—	—	—	—
Amortization of rate stabilization deferral	(54)	—	—	—	(35)	(19)	(15)	(4)	—
Discrete impacts from EIMA and FEJA ^(c)	(17)	—	(17)	—	—	—	—	—	—
Long-term incentive plan	(7)	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	51	35	—	—	8	5	2	2	1
Three Months Ended March 31, 2019									
Pension and non-pension postretirement benefit costs	\$ 106	\$ 31	\$ 24	\$ 2	\$ 15	\$ 23	\$ 6	\$ 4	\$ 4
Provision for uncollectible accounts	43	—	9	16	8	10	4	4	2
Other decommissioning-related activity ^(a)	(202)	(202)	—	—	—	—	—	—	—
Energy-related options ^(b)	37	37	—	—	—	—	—	—	—
Amortization of rate stabilization deferral	(6)	—	—	—	—	(6)	(7)	1	—
Discrete impacts from EIMA and FEJA ^(c)	28	—	28	—	—	—	—	—	—
Long-term incentive plan	25	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	53	34	1	—	8	9	2	2	1

- (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 9 — Asset Retirement Obligations of the Exelon 2019 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) Reflects the change in ComEd's distribution and energy efficiency formula rates. See Note 2 — 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, 2020									
Cash and cash equivalents	\$ 1,457	\$ 821	\$ 514	\$ 31	\$ 11	\$ 49	\$ 18	\$ 7	\$ 8
Restricted cash	414	150	211	7	1	37	33	—	3
Restricted cash included in other long-term assets	121	—	108	—	—	12	—	—	12
Total cash, cash equivalents and restricted cash	<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	358	146	150	6	1	36	33	—	2
Restricted cash included in other long-term assets	177	—	163	—	—	14	—	—	14
Total cash, cash equivalents and restricted cash	<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>
March 31, 2019									
Cash and cash equivalents	\$ 880	\$ 537	\$ 68	\$ 41	\$ 12	\$ 33	\$ 11	\$ 7	\$ 6
Restricted cash	223	139	17	6	4	39	35	1	3
Restricted cash included in other long-term assets	211	—	193	—	—	19	—	—	19
Total cash, cash equivalents and restricted cash	<u>\$ 1,314</u>	<u>\$ 676</u>	<u>\$ 278</u>	<u>\$ 47</u>	<u>\$ 16</u>	<u>\$ 91</u>	<u>\$ 46</u>	<u>\$ 8</u>	<u>\$ 28</u>
December 31, 2018									
Cash and cash equivalents	\$ 1,349	\$ 750	\$ 135	\$ 130	\$ 7	\$ 124	\$ 16	\$ 23	\$ 7
Restricted cash	247	153	29	5	6	43	37	1	4
Restricted cash included in other long-term assets	185	—	166	—	—	19	—	—	19
Total cash, cash equivalents and restricted cash	<u>\$ 1,781</u>	<u>\$ 903</u>	<u>\$ 330</u>	<u>\$ 135</u>	<u>\$ 13</u>	<u>\$ 186</u>	<u>\$ 53</u>	<u>\$ 24</u>	<u>\$ 30</u>

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the Exelon 2019 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, 2020									
Compensation-related accruals ^(a)	\$ 557	\$ 207	\$ 87	\$ 39	\$ 44	\$ 63	\$ 22	\$ 14	\$ 10
Taxes accrued	442	244	85	1	43	114	79	25	7
Interest accrued	407	84	69	33	38	78	37	20	19
December 31, 2019									
Compensation-related accruals ^(a)	\$ 1,052	\$ 422	\$ 171	\$ 58	\$ 78	\$ 101	\$ 28	\$ 19	\$ 15
Taxes accrued	414	222	83	3	26	117	90	14	8
Interest accrued	337	65	110	37	46	49	23	8	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,	
	2020	2019
Operating revenues from affiliates:		
ComEd ^{(a)(b)}	\$ 90	\$ 94
PECO ^(c)	37	45
BGE ^(d)	99	76
PHI	103	101
Pepco ^(e)	79	70
DPL ^(f)	22	23
ACE ^(g)	2	8
Other	1	1
Total operating revenues from affiliates (Generation)	\$ 330	\$ 317

(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, 2020, ComEd's Purchased power from Generation of \$97 million is recorded as Operating revenues from ComEd of \$90 million and Purchased power and fuel from ComEd of \$7 million at Generation. For the three months ended March 31, 2019, ComEd's Purchased power from Generation of \$97 million is recorded as Operating revenues from ComEd of \$94 million and Purchased power and fuel from ComEd of \$3 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.

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

Note 18 — Related Party Transactions

- (d) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs.
- (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 and gas 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,	
	2020	2019	2020	2019
Exelon				
BSC			\$ 113	\$ 99
PHISCO			14	22
Generation				
BSC	\$ 140	\$ 149	11	11
ComEd				
BSC	72	62	42	25
PECO				
BSC	37	37	16	22
BGE				
BSC	41	38	28	21
PHI				
BSC	37	32	16	19
PHISCO	—	—	14	22
Pepco				
BSC	21	21	6	8
PHISCO	30	33	6	9
DPL				
BSC	13	13	5	5
PHISCO	24	26	4	7
ACE				
BSC	11	11	4	4
PHISCO	22	23	4	6

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, 2020

Payables to affiliates:	Receivables from affiliates:									
	Generation	Comed	PECO	BGE	DPL	ACE	BSC	PHISCO	Other	Total
Generation		\$ 17	\$ —	\$ —	\$ 1	\$ —	\$ 67	\$ —	\$ 43	\$ 128
ComEd	\$ 69 (a)	—	—	—	—	—	42	—	3	114
PECO	25	—	—	—	—	—	19	—	7	51
BGE	22	—	—	—	—	—	27	—	3	52
PHI	—	—	—	—	—	—	3	—	10	13
Pepco	29	—	—	1	—	—	11	12	2	55
DPL	1	—	—	—	—	3	7	9	1	21
ACE	12	—	—	—	—	—	5	9	1	27
Other	9	1	—	—	—	1	—	—	—	11
Total	\$ 167	\$ 18	\$ —	\$ 1	\$ 1	\$ 4	\$ 181	\$ 30	\$ 70	\$ 472

December 31, 2019

Payables to affiliates:	Receivables from affiliates:									
	Generation	Comed	PECO	BGE	DPL	ACE	BSC	PHISCO	Other	Total
Generation		\$ 27	\$ —	\$ —	\$ —	\$ —	\$ 67	\$ —	\$ 23	\$ 117
ComEd	\$ 78 (a)	—	—	—	—	—	54	—	8	140
PECO	27	—	—	—	—	—	25	—	3	55
BGE	28	—	—	—	—	—	34	—	4	66
PHI	—	—	—	—	—	—	4	—	10	14
Pepco	34	—	—	—	—	—	16	15	1	66
DPL	7	—	—	—	—	3	10	11	1	32
ACE	7	—	—	—	—	—	7	10	1	25
Other	9	1	1	1	—	1	—	—	—	13
Total	\$ 190	\$ 28	\$ 1	\$ 1	\$ —	\$ 4	\$ 217	\$ 36	\$ 51	\$ 528

(a) At March 31, 2020 and December 31, 2019, Generation also had a contract liability with ComEd for \$27 million and \$37 million, respectively, that was included in Other liabilities on Generation's Consolidated Balance Sheets. At March 31, 2020 and December 31, 2019, ComEd had a Current Payable to Generation of \$42 million and \$41 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

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

Note 18 — Related Party Transactions

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 9 — Asset Retirement Obligations of the Exelon 2019 Form 10-K for additional information.

The following table presents noncurrent receivables from affiliates at ComEd and PECO which are recorded as noncurrent payables to affiliates at Generation:

	March 31, 2020	December 31, 2019
ComEd	\$ 2,040	\$ 2,622
PECO	261	480
Other	1	1
Total:	<u>\$ 2,302</u>	<u>\$ 3,103</u>

Long-term debt to financing trusts

The following table presents Long-term debt to financing trusts:

	March 31, 2020			December 31, 2019		
	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. Subsequent Events (Exelon and Generation)

Sales of Customer Accounts Receivable

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, whose maximum capacity is \$750 million, is scheduled to expire on April 7, 2021, unless renewed by the mutual consent of the parties in accordance with its terms. 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 deferred purchase price (DPP). Generation continues to service the receivables sold in exchange for a servicing fee.

On April 8, 2020, NER received approximately \$500 million in cash purchase price in accordance with the initial sale of approximately \$1.2 billion receivables to the Purchasers under the Facility.

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 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's principal subsidiaries and reportable segments.

Exelon's consolidated financial information includes the results of its 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.

COVID-19. The Registrants are responding to the global outbreak (pandemic) of COVID-19 and have taken steps to mitigate the potential risks to the Registrants posed by its spread. The Registrants provide a critical service to our customers which means that it is paramount that we keep our employees who operate our business safe and minimize unnecessary risk of exposure to the virus. The Registrants have taken extra precautions for our employees who work in the field and for employees who continue to work in our facilities, have implemented work from home policies where appropriate, and imposed travel limitations on our employees. In addition, the Registrants have updated our existing business continuity plans for our business units in the context of this pandemic.

The Registrants continue to implement strong physical and cyber-security measures to ensure that our systems remain functional in order to both serve our operational needs with a remote workforce and keep them running to ensure uninterrupted service to our customers.

There were no changes in internal control over financial reporting during the first quarter of 2020 as of result of COVID-19 that materially affected, or are reasonably likely to materially affect, any of the Registrants' internal control over financial reporting. See Item 4. Controls and Procedures for additional information.

Generation has temporarily suspended interruption of service for all retail residential customers for non-payment and temporarily ceased new late payment fees for all retail customers. The Utility Registrants have also temporarily suspended customer disconnections for non-payment and temporarily ceased new late fees for all customers and are restoring service to customers who were disconnected in the last twelve months upon request. There was no material increase in the Registrants' Customer allowance for credit losses at March 31, 2020 as a result of such measures. However, the Registrants expect an increase in Customer allowance for credit losses for the year ending December 31, 2020. Generation estimates a reduction in Net income due to an increase in credit loss expense of \$25 to \$75 million for the nine months ending December 31, 2020. The Utility Registrants do not expect a reduction in Net income. Typically, they recover credit loss expense through rate required programs or distribution base rate cases. For those jurisdictions without an existing rate required program to recover credit loss expense, the Utility Registrants are pursuing orders with their respective commissions to recover incremental costs being incurred as a result of COVID-19. In April of 2020, the MDPSC and the DCPSC issued orders authorizing the creation of regulatory assets to track incremental COVID-19 related costs, which will allow for assessment of recovery of those costs in future distribution base rate cases. PECO and DPL are pursuing similar orders with the PAPUC and the DPSC, respectively. ComEd and ACE have existing mechanisms for recovery of credit loss expense. The timing

of the recovery offset of the increase in credit loss expense could extend beyond 2020, which could have a negative impact on Net income for the year ending December 31, 2020.

Unfavorable economic conditions due to COVID-19 could depress demand for electricity and natural gas in the future. There was no material impact to the Registrants' Net income for the three months ended March 31, 2020. However, Generation estimates a reduction in Net income due to reduction in load of \$75 to \$225 million for the nine months ending December 31, 2020. Generation's load forecast is highly dependent on many factors including, but not limited to, the duration of the shelter in place restrictions and the speed and strength of the economic recovery. The Utility Registrants estimate a reduction in Net income due to reduction in load of \$20 to \$40 million for the nine months ending December 31, 2020, assuming shelter in place restrictions begin to lift in the third quarter of 2020. The Utility Registrants load forecast is dependent on, but not limited to, the duration of the shelter in place restrictions and the speed and strength of the economic recovery. A 1% change in load would result in the following change in Net income for the nine months ended December 31, 2020:

	Generation's Net Income	Utility Registrants' Net Income
Commercial & Industrial Customers	\$ 15	\$ 6
Residential Customers	7	7

To offset part of the unfavorable impacts from increase in credit loss expense and reduction in load, the Registrants identified and are pursuing approximately \$250 million in cost savings across Generation and the Utility Registrants.

The Registrants rely on the capital markets for publicly offered debt as well as the commercial paper markets to meet their financial commitments and short-term liquidity needs. As a result of the disruptions in the commercial paper markets in March of 2020, Generation borrowed \$1.5 billion on its revolving credit facility to refinance commercial paper. Generation repaid the \$1.5 billion borrowed on the revolving credit facility on April 3, 2020. Generation also entered into two short-term loan agreements in March of 2020 for an aggregate of \$500 million. On April 8, 2020, Generation received approximately \$500 million in cash after entering into an accounts receivable financing arrangement. On April 1, 2020, Exelon Corporate issued and sold \$2 billion in aggregate principal amount of notes, the proceeds of which will be used to repay existing debt upon maturity and for general corporate purposes. On April 24, 2020, Exelon Corporate entered into a credit agreement establishing a \$550 million 364-day revolving credit facility. This facility will be used by Exelon as an additional source of short-term liquidity over the next 12 months. Exelon Corporate and the Utility registrants continued to issue commercial paper in March of 2020, albeit at higher interest rates. See Liquidity and Capital Resources, Note 12 - Debt and Credit Agreements and Note 19 - Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants assessed long-lived assets, goodwill, and investments for recoverability and there were no material impairment charges recorded in the first quarter of 2020. Certain assumptions are highly sensitive to changes. Changes in significant assumptions could potentially result in future impairments, which could be material.

This is a rapidly evolving situation that could lead to extended disruption of economic activity in our markets. The Registrants will continue to monitor developments affecting our workforce, our customers and our suppliers and we will take additional precautions that we determine are necessary in order to mitigate the impacts. The extent to which COVID-19 may impact the Registrants' ability to operate their generating and transmission and distribution assets, the ability to access capital markets, and results of operations, including demand for electricity and natural gas, will depend on future developments, which are highly uncertain and cannot be predicted at this time. This includes new information that is emerging daily concerning the severity of COVID-19, the spread and proliferation of COVID-19 around the world, and third-party actions taken to contain its spread or treat it, among others.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth Exelon's GAAP consolidated Net Income attributable to common shareholders by Registrant for the three months ended March 31, 2020 compared to the same period in 2019. For additional information regarding the financial results for the three months ended March 31, 2020 and 2019 see the discussions of Results of Operations by Registrant.

	Three Months Ended March 31,		Favorable (unfavorable) variance
	2020	2019	
Exelon	\$ 582	\$ 907	\$ (325)
Generation	45	363	(318)
ComEd	168	157	11
PECO	140	168	(28)
BGE	181	160	21
PHI	108	117	(9)
Pepco	52	55	(3)
DPL	45	53	(8)
ACE	13	10	3
Other ^(a)	(60)	(58)	(2)

(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, 2020 Compared to Three Months Ended March 31, 2019. Net income attributable to common shareholders decreased by \$325 million and diluted earnings per average common share decreased to \$0.60 in 2020 from \$0.93 in 2019 primarily due to:

- Lower capacity revenue;
- Lower realized energy prices;
- Higher nuclear outage days;
- Higher net unrealized and realized losses NDT funds; and
- Unfavorable weather conditions at PECO, DPL Delaware and ACE.

The decreases were partially offset by:

- Higher mark-to-market gains;
- The approval of the New Jersey ZEC program in the second quarter of 2019;
- An income tax settlement at Generation;
- Regulatory rate increases at BGE, DPL, and ACE; and
- Higher electric distribution earnings at ComEd primarily due to distribution formula rate timing, partially offset by lower allowed electric distribution ROE due to a decrease in treasury rates.

Adjusted (non-GAAP) Operating Earnings. In addition to net income, Exelon evaluates its operating performance using the measure of Adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations

of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following tables provide a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three months ended March 31, 2020 compared to the same period in 2019.

	Three Months Ended March 31,			
	2020		2019	
	Earnings per Diluted Share		Earnings per Diluted Share	
<i>(All amounts in millions after tax)</i>				
Net Income Attributable to Common Shareholders	\$ 582	\$ 0.60	\$ 907	\$ 0.93
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of \$32 and \$12, respectively)	(94)	(0.10)	31	0.03
Unrealized (Gains) Losses Related to NDT Fund Investments (net of taxes of \$405 and \$161, respectively) ^(a)	485	0.50	(193)	(0.20)
Asset Impairments (net of taxes of \$1)	2	—	4	—
Plant Retirements and Divestitures (net of taxes of \$4 and \$6, respectively) ^(b)	13	0.01	19	0.02
Cost Management Program (net of taxes of \$3 and \$3, respectively) ^(c)	9	0.01	11	0.01
Income Tax-Related Adjustments (entire amount represents tax expense)	(2)	—	—	—
Noncontrolling Interests (net of taxes of \$30 and \$13, respectively) ^(d)	(144)	(0.15)	67	0.07
Adjusted (non-GAAP) Operating Earnings	\$ 851	\$ 0.87	\$ 846	\$ 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 and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates for 2020 and 2019 ranged from 26.0% 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 gains and losses related to NDT fund investments were 45.5% and 45.4% for the three months ended March 31, 2020 and 2019, respectively.

- (a) Reflects the impact of net unrealized gains and 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 2019, primarily reflects accelerated depreciation and amortization expenses associated with the early retirement of the TMI nuclear facility and a benefit associated with a rereasurement of the TMI ARO. 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 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 2020 Transactions and Developments

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 2020. See Note 2— 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	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois (Electric)	April 8, 2019	\$ (6)	\$ (17)	8.91 %	December 4, 2019	January 1, 2020

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement (Decrease) Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois (Electric)	April 16, 2020	\$ (11)	8.38 %	Fourth quarter of 2020
Pepco - District of Columbia (Electric)	May 30, 2019 (amended April 8, 2020)	\$ 147	10.3%	Fourth quarter of 2020
DPL - Maryland (Electric)	December 5, 2019 (amended April 23, 2020)	\$ 17	10.3%	Third quarter of 2020
DPL - Delaware (Gas)	February 21, 2020 (amended March 17, 2020)	\$ 9	10.3%	First quarter of 2021
DPL - Delaware (Electric)	March 6, 2020 (amended April 16, 2020)	\$ 24	10.3%	First quarter of 2021

Sales of Customer Accounts Receivable

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly owned by Generation, entered into an accounts receivable financing facility with a number of financial institutions and a commercial paper conduit to sell certain customer accounts receivables. Generation received approximately \$500 million of cash in accordance with the initial sale of approximately \$1.2 billion receivables. See Note 19 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information.

Other Key Business Drivers and Management Strategies

The following discussion of other key business 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 2019 Form 10-K and Note 14 — Commitments and Contingencies to the Consolidated Financial Statements in this report for additional information on various environmental matters.

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, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York and ERCOT reportable segments is 89%-92% and 70%-73% for 2020 and 2021, respectively. 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 2020 through 2024 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 results of operations, cash flows and financial positions.

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.

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, 2020, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2019. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in the Registrants' 2019 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,		(Unfavorable) Favorable Variance
	2020	2019	
Operating revenues	\$ 4,733	\$ 5,296	\$ (563)
Purchased power and fuel expense	2,704	3,205	501
Revenues net of purchased power and fuel expense	2,029	2,091	(62)
Other operating expenses			
Operating and maintenance	1,263	1,218	(45)
Depreciation and amortization	304	405	101
Taxes other than income	129	135	6
Total other operating expenses	1,696	1,758	62
Operating income	333	333	—
Other income and (deductions)			
Interest expense, net	(109)	(111)	2
Other, net	(771)	430	(1,201)
Total other income and (deductions)	(880)	319	(1,199)
(Loss) income before income taxes	(547)	652	(1,199)
Income taxes	(389)	224	613
Equity in losses of unconsolidated affiliates	(3)	(6)	3
Net (loss) income	(161)	422	(583)
Net (loss) income attributable to noncontrolling interests	(206)	59	(265)
Net income attributable to membership interest	\$ 45	\$ 363	\$ (318)

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019. Net income attributable to membership interest decreased by \$318 million primarily due to:

- Lower capacity revenue;
- Lower realized energy prices;
- Higher nuclear outage days; and
- Higher net unrealized and realized losses on NDT funds;

The decreases were partially offset by:

- Higher mark-to-market gains;
- The approval of the New Jersey ZEC program in the second quarter of 2019; and
- An income tax settlement.

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 4 - 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, 2020 compared to 2019, RNF by region were as follows. See Note 4 - 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
	2020	2019		
Mid-Atlantic ^(a)	\$ 567	\$ 683	\$ (116)	(17.0)%
Midwest ^(b)	727	771	(44)	(5.7)%
New York	193	265	(72)	(27.2)%
ERCOT	80	74	6	8.1 %
Other Power Regions	158	156	2	1.3 %
Total electric revenues net of purchased power and fuel expense	1,725	1,949	(224)	(11.5)%
Mark-to-market gains (losses)	131	(28)	159	567.9 %
Other	173	170	3	1.8 %
Total revenue net of purchased power and fuel expense	\$ 2,029	\$ 2,091	\$ (62)	(3.0)%

(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 (GWhs)	Three Months Ended March 31,		Variance	% Change
	2020	2019		
Nuclear Generation^(a)				
Mid-Atlantic	12,784	15,080	(2,296)	(15.2)%
Midwest	23,598	23,733	(135)	(0.6)%
New York	6,173	6,902	(729)	(10.6)%
Total Nuclear Generation	42,555	45,715	(3,160)	(6.9)%
Fossil and Renewables				
Mid-Atlantic	853	951	(98)	(10.3)%
Midwest	388	392	(4)	(1.0)%
New York	1	1	—	— %
ERCOT	3,012	3,078	(66)	(2.1)%
Other Power Regions	3,508	3,141	367	11.7 %
Total Fossil and Renewables	7,762	7,563	199	2.6 %
Purchased Power				
Mid-Atlantic	5,943	2,566	3,377	131.6 %
Midwest	288	288	—	— %
ERCOT	991	1,042	(51)	(4.9)%
Other Power Regions	12,167	12,569	(402)	(3.2)%
Total Purchased Power	19,389	16,465	2,924	17.8 %
Total Supply/Sales by Region				
Mid-Atlantic ^(b)	19,580	18,597	983	5.3 %
Midwest ^(b)	24,274	24,413	(139)	(0.6)%
New York	6,174	6,903	(729)	(10.6)%
ERCOT	4,003	4,120	(117)	(2.8)%
Other Power Regions	15,675	15,710	(35)	(0.2)%
Total Supply/Sales by Region	69,706	69,743	(37)	(0.1)%

(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, 2020 compared to 2019, changes in **RNF** by region were as follows:

	2020 vs. 2019	
	Increase/ (Decrease)	Description
Mid-Atlantic	\$ (116)	<ul style="list-style-type: none"> • decreased capacity revenue • decreased revenue due to permanent cease of generation operations at Three Mile Island in the third quarter of 2019 • lower realized energy prices, partially offset by • increased ZEC revenues due to the approval of the NJ ZEC program in the second quarter of 2019
Midwest	(44)	<ul style="list-style-type: none"> • decreased capacity revenue • lower realized energy prices
New York	(72)	<ul style="list-style-type: none"> • lower realized energy prices • increased nuclear outage days
ERCOT	6	<ul style="list-style-type: none"> • higher portfolio optimization
Other Power Regions	2	<ul style="list-style-type: none"> • higher portfolio optimization, partially offset by • decreased capacity revenue
Mark-to-market ^(a)	159	<ul style="list-style-type: none"> • gains on economic hedging activities of \$131 million in 2020 compared to losses of \$28 million in 2019
Other	3	<ul style="list-style-type: none"> • no significant changes
Total	<u>\$ (62)</u>	

(a) See Note 11 — Derivative Financial Instruments for additional information on mark-to-market gains (losses).

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,	
	2020	2019
Nuclear fleet capacity factor	93.9%	97.1%
Refueling outage days	94	74
Non-refueling outage days	11	—

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

	Three Months Ended March 31,	
	Increase (Decrease)	
Plant retirements and divestitures ^(a)	\$	82
Nuclear refueling outage costs, including the co-owned Salem plants		42
Credit loss expense		3
Pension and non-pension postretirement benefits expense		(5)
Accretion expense		(10)
Corporate allocations		(11)
Labor, other benefits, contracting and materials ^(b)		(56)
Increase in operating and maintenance expense	\$	45

(a) Primarily reflects increase from prior year due to the benefit recorded in the first quarter of 2019 for the remeasurement of the TMI ARO.

(b) Primarily reflects decreased costs related to the permanent cease of generation operations at TMI and lower labor costs resulting from previous cost management programs.

Depreciation and amortization expense for the three months ended March 31, 2020 compared to the same period in 2019 decreased primarily due to the permanent cease of generation operations at Three Mile Island in the third quarter of 2019.

Other, net for the three months ended March 31, 2020 compared to the same period in 2019 decreased due to activity associated with NDT funds as described in the table below:

	2020		2019	
Net unrealized (losses) gains on NDT funds ^(a)	\$	(706)	\$	280
Net realized gains on sale of NDT funds ^(a)		55		29
Interest and dividend income on NDT funds ^(a)		27		25
Contractual elimination of income tax expense ^(b)		(176)		85
Other		29		11
Total other, net	\$	(771)	\$	430

(a) Unrealized gains (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.

Effective income tax rates were 71.1% and 34.3% for the three months ended March 31, 2020 and 2019, respectively. The change is primarily related to a one-time adjustment partially offset by renewable tax credits. 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, 2020 compared to the same period in 2019 decreased primarily due to unrealized losses on NDT fund investments for CENG.

Results of Operations — ComEd

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2020	2019	
Operating revenues	\$ 1,439	\$ 1,408	\$ 31
Operating expenses			
Purchased power expense	486	485	(1)
Operating and maintenance	317	321	4
Depreciation and amortization	273	251	(22)
Taxes other than income	75	78	3
Total operating expenses	<u>1,151</u>	<u>1,135</u>	<u>(16)</u>
Gain on sales of assets	<u>—</u>	<u>3</u>	<u>(3)</u>
Operating income	<u>288</u>	<u>276</u>	<u>12</u>
Other income and (deductions)			
Interest expense, net	(94)	(87)	(7)
Other, net	10	8	2
Total other income and (deductions)	<u>(84)</u>	<u>(79)</u>	<u>(5)</u>
Income before income taxes	<u>204</u>	<u>197</u>	<u>7</u>
Income taxes	<u>36</u>	<u>40</u>	<u>4</u>
Net income	<u>\$ 168</u>	<u>\$ 157</u>	<u>\$ 11</u>

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019. Net income increased \$11 million as compared to the same period in 2019, primarily due to higher electric distribution formula rate earnings (reflecting the impacts of higher rate base and distribution formula rate timing, partially offset by lower allowed electric distribution ROE due to a decrease in treasury rates).

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

	Three Months Ended March 31, 2020
	Increase (Decrease)
Electric distribution	\$ 22
Transmission	(7)
Energy efficiency	12
	<u>27</u>
Regulatory required programs	4
Total increase	<u>\$ 31</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 a change to the electric distribution formula rate pursuant to FEJA.

Distribution Revenue. EIMA and FEJA provide for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, (e.g., severe weather and storm restoration), investments being recovered, and allowed ROE. Electric distribution revenue increased during the three months ended March 31, 2020 as compared to the same period in 2019, primarily due to the impact of higher rate base, higher fully recoverable costs and distribution

formula rate timing, offset by lower allowed ROE due to a decrease in treasury rates. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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. Transmission revenue decreased for the three months ended March 31, 2020 as compared to the same period in 2019, primarily due to the impact of decreased peak load partially offset by higher fully recoverable costs. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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, 2020 as compared to the same period in 2019, primarily due to the increased regulatory asset amortization. See Depreciation and amortization expense discussions below and Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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 and fuel 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 but impact Operating revenues related to supplied electricity. Drivers of Operating revenues related to electricity, ZEC and REC procurement costs and participation in customer choice programs are fully offset by their impact on Purchased power and fuel expense. ComEd recovers electricity, ZEC and REC procurement costs from customers without mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The increase of \$1 million in **Purchased power and fuel expense** is offset in Operating revenues as part of regulatory required programs.

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

	Three Months Ended March 31, 2020
	(Decrease) Increase
Labor, other benefits, contracting and materials	\$ (10)
Storm-related costs	(7)
BSC costs	10
Pension and non-pension postretirement benefits expense	3
Other	1
	(3)
Regulatory required programs ^(a)	(1)
Total decrease	\$ (4)

(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. During the three months ended March 31, 2020, ComEd recorded a net decrease in credit losses account due to the timing of regulatory cost recovery. An equal and offsetting amount has been recognized in Operating revenues for the period presented.

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

	Three Months Ended March 31, 2020	
	Increase	
Depreciation and amortization ^(a)	\$	13
Regulatory asset amortization ^(b)		9
Total increase	\$	22

(a) Reflects ongoing capital expenditures.

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

Effective income tax rate was 17.6% and 20.3% for the three months ended March 31, 2020 and 2019, 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
	2020	2019	
Operating revenues	\$ 813	\$ 900	\$ (87)
Operating expenses			
Purchased power and fuel expense	283	331	48
Operating and maintenance	217	225	8
Depreciation and amortization	86	81	(5)
Taxes other than income	39	41	2
Total operating expenses	625	678	53
Operating income	188	222	(34)
Other income and (deductions)			
Interest expense, net	(36)	(33)	(3)
Other, net	3	4	(1)
Total other income and (deductions)	(33)	(29)	(4)
Income before income taxes	155	193	(38)
Income taxes	15	25	10
Net income	\$ 140	\$ 168	\$ (28)

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019. Net income decreased by \$28 million primarily due to unfavorable weather conditions.

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

	Three Months Ended March 31, 2020		
	Increase (Decrease)		
	Electric	Gas	Total
Weather	\$ (27)	\$ (21)	\$ (48)
Volume	(5)	(1)	(6)
Pricing	8	2	10
Transmission	2	—	2
	(22)	(20)	(42)
Regulatory required programs	5	(50)	(45)
Total decrease	\$ (17)	\$ (70)	\$ (87)

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, 2020 compared to the same period in 2019, Operating revenues related to weather decreased by the impact of unfavorable weather conditions in PECO’s service territory.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in PECO's service territory. The changes in heating and cooling degree-days in PECO's service territory for the three months ended March 31, 2020 compared to the same period in 2019 and normal weather consisted of the following:

Heating and Cooling Degree-Days	2020	2019	Normal	% Change	
				From 2019	2020 vs. Normal
Three Months Ended March 31,					
Heating Degree-Days	1,989	2,432	2,419	(18.2)%	(17.8)%
Cooling Degree-Days	—	2	1	(100.0)%	(100.0)%

Volume. Electric volume, exclusive of the effects of weather, for the three months ended March 31, 2020 compared to the same period in 2019, decreased due to the impact of energy efficiency initiatives on customer usages for residential, commercial and industrial electric classes, partially offset by the impact of customer growth.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,		% Change	Weather - Normal % Change^(b)
	2020	2019		
Residential	3,254	3,641	(10.6)%	(0.7)%
Small commercial & industrial	1,905	2,066	(7.8)%	(3.2)%
Large commercial & industrial	3,421	3,571	(4.2)%	(3.4)%
Public authorities & electric railroads	151	195	(22.6)%	(22.7)%
Total electric retail deliveries^(a)	8,731	9,473	(7.8)%	(2.7)%

Number of Electric Customers	As of March 31,	
	2020	2019
Residential	1,499,019	1,485,698
Small commercial & industrial	154,056	153,042
Large commercial & industrial	3,093	3,107
Public authorities & electric railroads	10,096	9,638
Total	1,666,264	1,651,485

(a) Reflects delivery volumes from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Natural Gas Deliveries to Customers (in mmcf)	Three Months Ended March 31,		% Change	Weather - Normal % Change^(b)
	2020	2019		
Residential	17,282	21,218	(18.6)%	(0.9)%
Small commercial & industrial	8,809	10,644	(17.2)%	— %
Large commercial & industrial	9	19	(52.6)%	(6.3)%
Transportation	7,135	7,973	(10.5)%	(1.9)%
Total natural gas retail deliveries^(a)	33,235	39,854	(16.6)%	(0.9)%

<u>Number of Natural Gas Customers</u>	<u>As of March 31,</u>	
	<u>2020</u>	<u>2019</u>
Residential	489,063	483,560
Small commercial & industrial	44,509	44,274
Large commercial & industrial	5	1
Transportation	727	744
Total	534,304	528,579

- (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, 2020 compared to the same period in 2019 increased primarily due to higher overall effective rates due to decreased usage across all major customer classes. Additionally, the increase represents revenue from higher natural gas distribution rates.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue for the three months ended March 31, 2020 compared to the same period in 2019 remained relatively consistent.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency, PGC, and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense and Income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries but impact Operating revenues related to supplied electricity and natural gas. Drivers of Operating revenues related to commodity and REC procurement costs and participation in customer choice programs are fully offset by their impact on Purchased power and fuel expense. PECO recovers electricity, natural gas and REC procurement costs from customers without mark-up.

See Note 4— Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The decrease of \$48 million 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:

	<u>Three Months Ended</u>	
	<u>March 31, 2020</u>	
	<u>(Decrease) Increase</u>	
Storm-related costs	\$	(8)
Labor, other benefits, contracting and materials		(5)
Pension and non-pension postretirement benefits expense		(1)
Credit loss expense		1
Other		5
Total decrease	\$	(8)

Depreciation and Amortization Expense for the three months ended March 31, 2020 compared to the same period in 2019 increased primarily due to ongoing capital expenditures.

Effective Income Tax Rates were 9.7% and 13.0% for the three months ended March 31, 2020 and 2019, 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
	2020	2019	
Operating revenues	\$ 937	\$ 976	\$ (39)
Operating expenses			
Purchased power and fuel expense	288	360	72
Operating and maintenance	188	192	4
Depreciation and amortization	143	136	(7)
Taxes other than income	69	68	(1)
Total operating expenses	<u>688</u>	<u>756</u>	<u>68</u>
Operating income	<u>249</u>	<u>220</u>	<u>29</u>
Other income and (deductions)			
Interest expense, net	(32)	(29)	(3)
Other, net	5	5	—
Total other income and (deductions)	<u>(27)</u>	<u>(24)</u>	<u>(3)</u>
Income before income taxes	<u>222</u>	<u>196</u>	<u>26</u>
Income taxes	41	36	(5)
Net income	<u>\$ 181</u>	<u>\$ 160</u>	<u>\$ 21</u>

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019. Net income increased by \$21 million primarily due to higher natural gas and electric distribution rates that became effective December 2019.

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

	Three Months Ended March 31, 2020		
	Increase (Decrease)		
	Electric	Gas	Total
Distribution	\$ 9	\$ 29	\$ 38
Transmission	6	—	6
Other	3	(1)	2
	<u>18</u>	<u>28</u>	<u>46</u>
Regulatory required programs	(64)	(21)	(85)
Total (decrease) increase	<u>\$ (46)</u>	<u>\$ 7</u>	<u>\$ (39)</u>

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.

<u>Number of Electric Customers</u>	As of March 31,	
	2020	2019
Residential	1,181,329	1,171,027
Small commercial & industrial	114,697	113,976
Large commercial & industrial	12,376	12,278
Public authorities & electric railroads	265	266
Total	1,308,667	1,297,547

<u>Number of Natural Gas Customers</u>	As of March 31,	
	2020	2019
Residential	641,608	635,241
Small commercial & industrial	38,381	38,322
Large commercial & industrial	6,078	5,981
Total	686,067	679,544

Distribution Revenue increased for the three months ended March 31, 2020, compared to the same period in 2019, primarily due to the impact of higher natural gas and electric distribution rates that became effective in December 2019. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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. See Operating and maintenance expense below and Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other revenue includes revenue related to mutual assistance, administrative charges, off-system sales, and late payment charges.

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 Purchase power and fuel expenses, Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income. 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 but impact Operating revenues related to supplied electricity and natural gas. Drivers of Operating revenues related to commodity procurement costs and participation in customer choice programs are fully offset by their impact on Purchase power and fuel expense. BGE recovers electricity, natural gas and procurement costs from customers with a slight mark-up.

See Note 4 — Segment Information of the Combined Notes to the Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

The decrease of \$72 million in **Purchased power and fuel expense** is offset in Operating revenues as part of regulatory required programs.

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

	<u>Three Months Ended March 31, 2020</u>
	<u>(Decrease) Increase</u>
Storm-related costs	\$ (6)
Credit loss expense	(1)
Labor, other benefits, contracting and materials	2
BSC costs	3
Other	(1)
	<u>(3)</u>
Regulatory Required Programs	(1)
Total decrease	<u>\$ (4)</u>

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

	<u>Three Months Ended March 31, 2020</u>
	<u>Increase (Decrease)</u>
Depreciation and amortization ^(a)	\$ 12
Regulatory required programs	(5)
Total increase	<u>\$ 7</u>

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Effective income tax rates were 18.5% and 18.4% for the three months ended March 31, 2020 and 2019, 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 — 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. See the results of operations for Pepco, DPL and ACE for additional information.

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2020	2019	
PHI	\$ 108	\$ 117	\$ (9)
Pepco	52	55	(3)
DPL	45	53	(8)
ACE	13	10	3
Other ^(a)	(2)	(1)	(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, 2020 Compared to Three Months Ended March 31, 2019. Net Income decreased by \$9 million primarily due to an increase in various expenses and unfavorable weather conditions in DPL's Delaware and ACE's service territory, partially offset by higher electric and natural gas distribution rates, and higher transmission rates.

Results of Operations — Pepco

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2020	2019	
Operating revenues	\$ 544	\$ 575	\$ (31)
Operating expenses			
Purchased power expense	164	187	23
Operating and maintenance	111	118	7
Depreciation and amortization	95	94	(1)
Taxes other than income taxes	92	92	—
Total operating expenses	462	491	29
Operating income	82	84	(2)
Other income and (deductions)			
Interest expense, net	(34)	(34)	—
Other, net	9	7	2
Total other income and (deductions)	(25)	(27)	2
Income before income taxes	57	57	—
Income taxes	5	2	(3)
Net income	\$ 52	\$ 55	\$ (3)

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019. Net income remained relatively consistent.

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

	Three Months Ended March 31, 2020
	Increase (Decrease)
Volume	\$ 2
Transmission	(2)
Other	(1)
Regulatory required programs	(30)
Total decrease	\$ (31)

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.

Volume, exclusive of the effects of weather, increased for the three months ended March 31, 2020 compared to the same period in 2019, primarily due to the impact of residential customer growth.

<u>Number of Electric Customers</u>	<u>As of March 31,</u>	
	<u>2020</u>	<u>2019</u>
Residential	820,283	809,845
Small commercial & industrial	54,304	54,295
Large commercial & industrial	22,248	22,030
Public authorities & electric railroads	169	153
Total	897,004	886,323

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. Transmission revenues remained relatively consistent for the three months ended March 31, 2020 compared to the same period in 2019.

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, but impact Operating revenues related to supplied electricity. Drivers of Operating revenues related to commodity and REC procurement costs and participation in customer choice programs are fully offset by their impact on Purchased power expense. Pepco recovers electricity and REC procurement costs from customers with a slight mark-up.

See Note 4 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

The decrease of \$23 million 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:

	<u>Three Months Ended</u> <u>March 31, 2020</u>
	<u>Increase (Decrease)</u>
Labor, other benefits, contracting and materials	\$ 6
Pension and non-pension postretirement benefits expense	(1)
Credit loss expense	(1)
Storm-related costs	(2)
BSC and PHISCO costs	(3)
Other	(6)
Total decrease	\$ (7)

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

	Three Months Ended March 31, 2020
	Increase (Decrease)
Depreciation and amortization ^(a)	\$ 5
Regulatory required programs	(4)
Total increase	\$ 1

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Effective income tax rates were 8.8% and 3.5% for the three months ended March 31, 2020 and 2019, 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
	2020	2019	
Operating revenues	\$ 350	\$ 380	\$ (30)
Operating expenses			
Purchased power and fuel expense	141	164	23
Operating and maintenance	79	84	5
Depreciation and amortization	48	46	(2)
Taxes other than income taxes	16	14	(2)
Total operating expenses	284	308	24
Operating income	66	72	(6)
Other income and (deductions)			
Interest expense, net	(16)	(15)	(1)
Other, net	2	3	(1)
Total other income and (deductions)	(14)	(12)	(2)
Income before income taxes	52	60	(8)
Income taxes	7	7	—
Net income	\$ 45	\$ 53	\$ (8)

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019. Net income decreased by \$8 million primarily due to increase in various expenses and unfavorable weather conditions in DPL's Delaware service territory, partially offset by higher natural gas distribution rates and higher transmission rates that became effective in June 2019.

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

	Three Months Ended March 31, 2020		
	Increase (Decrease)		
	Electric	Gas	Total
Weather	\$ (6)	\$ (7)	\$ (13)
Volume	1	—	1
Distribution	1	4	5
Transmission	3	—	3
Other	(1)	—	(1)
	(2)	(3)	(5)
Regulatory required programs	(21)	(4)	(25)
Total decrease	\$ (23)	\$ (7)	\$ (30)

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, 2020 compared to the same period in 2019, Operating revenues related to weather decreased due to the impact of unfavorable weather conditions in DPL's Delaware 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 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, 2020 compared to same period in 2019 and normal weather consisted of the following:

Delaware Electric Service Territory	% Change				
	2020	2019	Normal	2020 vs. 2019	2020 vs. Normal
Three Months Ended March 31,					
Heating Degree-Days	2,003	2,522	2,513	(20.6)%	(20.3)%

Delaware Natural Gas Service Territory	% Change				
	2020	2019	Normal	2020 vs. 2019	2020 vs. Normal
Three Months Ended March 31,					
Heating Degree-Days	2,003	2,522	2,498	(20.6)%	(19.8)%

Volume, exclusive of the effects of weather, remained relatively consistent for the three months ended March 31, 2020 compared to the same period in 2019.

Electric Retail Deliveries to Delaware Customers (in GWhs)	Three Months Ended March 31,			Weather - Normal % Change ^(b)
	2020	2019	% Change	
Residential	743	851	(12.7)%	(1.0)%
Small commercial & industrial	296	321	(7.8)%	(2.2)%
Large commercial & industrial	823	810	1.6 %	3.1 %
Public authorities & electric railroads	8	8	— %	1.8 %
Total electric retail deliveries ^(a)	1,870	1,990	(6.0)%	0.5 %

Number of Total Electric Customers (Maryland and Delaware)	As of March 31,	
	2020	2019
Residential	469,082	464,638
Small commercial & industrial	61,769	61,391
Large commercial & industrial	1,414	1,400
Public authorities & electric railroads	612	620
Total	532,877	528,049

(a) Reflects delivery volumes from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 20-year average.

Natural Gas Retail Deliveries to Delaware Customers (in mmcf)	Three Months Ended March 31,			Weather - Normal % Change ^(b)
	2020	2019	% Change	
Residential	3,647	4,607	(20.8)%	(0.7)%
Small commercial & industrial	1,671	2,020	(17.3)%	2.5 %
Large commercial & industrial	452	523	(13.6)%	(13.6)%
Transportation	2,108	2,218	(5.0)%	4.1 %
Total natural gas deliveries ^(a)	7,878	9,368	(15.9)%	0.4 %

<u>Number of Delaware Natural Gas Customers</u>	<u>As of March 31,</u>	
	<u>2020</u>	<u>2019</u>
Residential	126,209	124,575
Small commercial & industrial	10,004	10,023
Large commercial & industrial	17	18
Transportation	159	157
Total	136,389	134,773

- (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, 2020 compared to the same period in 2019 primarily due to higher natural gas distribution rates due to the Gas Distribution System Improvement Charge (DSIC) fully implemented in Q1 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 years. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue increased for the three months ended March 31, 2020 compared to the same period in 2019 due to rate increases that became effective in June 2019 and an increase in the highest daily peak load.

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, but impact Operating revenues related to supplied electricity. Drivers of Operating revenues related to commodity and REC procurement costs and participation in customer choice programs are fully offset by their impact on Purchased power expense. DPL recovers electricity and REC procurement costs from customers with a slight mark-up and natural gas costs from customers without mark-up.

See Note 4 - Segment Information for the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

The decrease of \$23 million 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, 2020
	Increase (Decrease)
Labor, other benefits, contracting and materials	\$ 1
Pension and non-pension postretirement benefits expense	(1)
Credit loss expense	(1)
BSC and PHISCO costs	(2)
Other	(2)
Total decrease	<u>\$ (5)</u>

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

	Three Months Ended March 31, 2020
	Increase (Decrease)
Depreciation and amortization ^(a)	\$ 3
Regulatory required programs	(1)
Total increase	<u>\$ 2</u>

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Effective income tax rates were 13.5% and 11.7% for the three months ended March 31, 2020 and 2019, 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
	2020	2019	
Operating revenues	\$ 276	\$ 273	\$ 3
Operating expenses			
Purchased power expense	128	139	11
Operating and maintenance	78	81	3
Depreciation and amortization	43	31	(12)
Taxes other than income taxes	2	1	(1)
Total operating expenses	251	252	1
Gain on sales of assets	2	—	2
Operating income	27	21	6
Other income and (deductions)			
Interest expense, net	(15)	(14)	(1)
Other, net	2	3	(1)
Total other income and (deductions)	(13)	(11)	(2)
Income before income taxes	14	10	4
Income taxes	1	—	(1)
Net income	\$ 13	\$ 10	\$ 3

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019. Net income increased by \$3 million with the same period in 2019 due to higher electric distribution rates that became effective in April 2019, transmission rate increases that became effective in June 2019, partially offset by increased depreciation and amortization due to ongoing capital expenditures, and unfavorable weather conditions in ACE's service territory.

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

	Three Months Ended March 31, 2020
	(Decrease) Increase
Weather	\$ (4)
Volume	(3)
Distribution	15
Transmission	6
	14
Regulatory required programs	(11)
Total increase	\$ 3

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 a decrease related to weather for the three months ended March 31, 2020 compared to same period in 2019 due to the impact of unfavorable 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. There were no cooling degree days in ACE's service territory for the three months ended March 31, 2020 or during the same period in 2019. The changes in heating degree days in ACE's service territory for the three months ended March 31, 2020 compared to same period in 2019 consisted of the following:

Heating and Cooling Degree-Days Three Months Ended March 31,	2020	2019	Normal	% Change	
				2020 vs. 2019	2020 vs. Normal
Heating Degree-Days	1,948	2,506	2,492	(22.3)%	(21.8)%

Volume, exclusive of the effects of weather, decreased for the three months ended March 31, 2020 compared to the same period in 2019, primarily due to lower average residential usage.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,		% Change	Weather - Normal % Change ^(b)
	2020	2019		
Residential	810	908	(10.8)%	(3.2)%
Small commercial & industrial	294	310	(5.2)%	(0.1)%
Large commercial & industrial	735	791	(7.1)%	(5.5)%
Public authorities & electric railroads	13	13	— %	(3.9)%
Total electric retail deliveries ^(a)	1,852	2,022	(8.4)%	(3.6)%

Number of Electric Customers	As of March 31,	
	2020	2019
Residential	495,444	491,935
Small commercial & industrial	61,470	61,377
Large commercial & industrial	3,355	3,494
Public authorities & electric railroads	684	661
Total	560,953	557,467

(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 increased for the three months ended March 31, 2020 compared to the same period in 2019 primarily due to higher electric distribution rates that became effective in April 2019.

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. Transmission revenue increased for the three months ended March 31, 2020 compared to the same period in 2019 primarily due to rate increases that became effective in June 2019 and an increase in the highest daily peak load.

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 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, but impact Operating revenues related to supplied electricity. Drivers of Operating revenues related to commodity, REC and ZEC procurement costs and participation in customer

choice programs are fully offset by their impact on Purchased power expense. ACE recovers electricity, REC and ZEC procurement costs from customers without mark-up.

See Note 4 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

The decrease of \$11 million 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, 2020
	Increase (Decrease)
Labor, other benefits, contracting and materials	\$ 3
Credit loss expense ^(a)	(1)
Storm-related costs	(1)
BSC and PHISCO costs	(1)
Other	(4)
	(4)
Regulatory required programs	1
Total decrease	<u>\$ (3)</u>

(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 a rider mechanism. An equal and offsetting amount has been recognized in Operating revenues.

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

	Three Months Ended March 31, 2020
	Increase (Decrease)
Depreciation and amortization ^(a)	\$ 9
Regulatory asset amortization	1
Regulatory required programs	2
Total increase	<u>\$ 12</u>

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Gain on sale of assets for the three months ended March 31, 2020 compared to the same period in 2019 increased due to the sale of land in February 2020.

Effective income tax rates were 7.1% and 0.0% for the three months ended March 31, 2020 and 2019, 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 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. As a result of disruptions in the commercial paper markets due to COVID-19 in March of 2020, Generation borrowed \$1.5 billion on its revolving credit facility to refinance commercial paper. Generation repaid the \$1.5 billion borrowed on the revolving credit facility on April 3, 2020 using funds from short-term loans issued in March 2020, cash proceeds from the sale of certain customer accounts receivable, and borrowings from the Exelon intercompany money pool. See Note 19 - Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information on the sale of customer accounts receivable. Exelon Corporate and the Utility Registrants continued to issue commercial paper in March, albeit at higher interest rates. See Executive Overview for additional information on COVID-19. The Registrants continue to 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 other postretirement benefit 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.

Despite disruptions in the financial markets due to COVID-19, the Registrants have been able to fund their liquidity needs to date. As of December 31, 2019, Exelon had approximately \$4.0 billion of long-term debt that matures in 2020, excluding project financings and floating rate long-term debt. Of this, as of April 1, 2020, Exelon has redeemed or refinanced approximately \$2.6 billion that is maturing in 2020. Of the remaining amount of \$1.4 billion on Exelon's and Generation's Consolidated Balance Sheet, approximately \$0.2 billion matures on June 1, 2020 and the remainder primarily matures in the fourth quarter of 2020. Exelon and Generation have a number of sources of liquidity available to them, which can be used to repay the long-term debt maturing in 2020. However, COVID-19 could negatively affect the Registrants' ability to access capital markets and the Registrants cannot predict the impacts of COVID-19 on the financial markets.

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 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 7 — 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 fund investments could appreciate in value. A shortfall could require that Generation address the shortfall by, among other things, obtaining a parental guarantee 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. 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, the NRC must approve an exemption in order for the plant's owner(s) to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e., spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s) without reimbursement from or access to the NDT funds. The ultimate costs for spent fuel management may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the DOE reimbursement agreements.

As of March 31, 2020, Exelon would not be required to post a parental guarantee 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. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on nonrecourse debt. Refer to Note 16 — Debt and Credit Agreements of the Exelon 2019 Form 10-K for additional information on credit facilities.

Cash Flows from Operating Activities (All Registrants)

General

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.

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 Notes 3 — Regulatory Matters and 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2019 Form 10-K for additional information of 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, 2020 and 2019 by Registrant:

Increase (Decrease) in cash flows from operating activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income	\$ (590)	\$ (583)	\$ 11	\$ (28)	\$ 21	\$ (9)	\$ (3)	\$ (8)	\$ 3
Adjustments to reconcile net income to cash:									
Non-cash operating activities	429	530	(10)	8	(23)	(18)	(13)	(8)	10
Pension and non-pension postretirement benefit contributions	(203)	(91)	(76)	9	(24)	(21)	—	—	(2)
Income taxes	(197)	(204)	(12)	(6)	(1)	11	2	2	3
Changes in working capital and other noncurrent assets and liabilities	561	365	54	85	53	40	43	20	(18)
Option premiums received, net	(44)	(44)	—	—	—	—	—	—	—
Collateral posted, net	80	65	16	—	1	—	—	—	—
Increase (Decrease) in cash flows from operating activities	\$ 36	\$ 38	\$ (17)	\$ 68	\$ 27	\$ 3	\$ 29	\$ 6	\$ (4)

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, 2020 and 2019 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 activity**.
- 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**.
- 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 OTC 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, 2020 and 2019 by Registrant:

(Decrease) Increase in cash flows from investing activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	\$ (143)	\$ (47)	\$ (3)	\$ (37)	\$ (25)	\$ (18)	\$ (36)	\$ (17)	\$ 27
Proceeds from NDT fund sales, net	(98)	(98)	—	—	—	—	—	—	—
Proceeds from sales of assets and businesses	(8)	(8)	—	—	—	—	—	—	—
Changes in intercompany money pool	—	(254)	—	(22)	—	—	(114)	—	—
Other investing activities	(40)	(31)	(6)	(1)	(7)	—	(5)	(4)	6
(Decrease) Increase in cash flows from investing activities	\$ (289)	\$ (438)	\$ (9)	\$ (60)	\$ (32)	\$ (18)	\$ (155)	\$ (21)	\$ 33

Significant investing cash flow impacts for the Registrants for three months ended March 31, 2020 and 2019 were as follows:

- Variances in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. Refer below for additional information on projected capital expenditure spending.
- Changes in **intercompany money pool** are driven by short-term borrowing needs. Refer to more information regarding the intercompany money pool below.

Capital Expenditure Spending

As of March 31, 2020, the most recent estimates of capital expenditures for plant additions and improvements for 2020 are as follows:

(in millions)	Transmission	Distribution	Gas	Total
Exelon	N/A	N/A	N/A	\$ 8,050
Generation	N/A	N/A	N/A	1,600
ComEd	450	1,875	N/A	2,325
PECO	150	700	275	1,125
BGE	275	550	450	1,275
PHI	425	1,100	100	1,625
Pepco	150	650	N/A	800
DPL	125	225	100	450
ACE	150	225	N/A	375

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

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, 2020 and 2019 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	\$ 69	\$ 775	\$ (452)	\$ —	\$ (5)	\$ (247)	\$ (147)	\$ (7)	\$ (93)
Long-term debt, net	1,570	519	900	—	—	149	150	—	(1)
Changes in intercompany money pool	—	100	—	—	—	7	—	37	77
Dividends paid on common stock	(21)	—	2	5	(6)	—	(4)	(11)	(11)
Distributions to member	—	(243)	—	—	—	(6)	—	—	—
Contributions from parent/member	—	—	62	86	—	125	123	6	(4)
Other financing activities	(28)	(2)	(4)	—	—	(1)	(1)	—	—
Increase (Decrease) in cash flows from financing activities	\$ 1,590	\$ 1,149	\$ 508	\$ 91	\$ (11)	\$ 27	\$ 121	\$ 25	\$ (32)

Significant financing cash flow impacts for the Registrants for the three months ended March 31, 2020 and 2019 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 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 Consolidated Financial Statements for additional information on debt issuances. Refer to debt redemptions tables below for more 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 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements

of the Exelon 2019 Form 10-K for additional information on dividend restrictions. See below for quarterly dividends declared.

- For the three months ended March 31, 2020, other financing activities primarily consist 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, 2020, the following long-term debt was retired and/or redeemed:

Company ^(a)	Type	Interest Rate	Maturity	Amount
Generation	Senior Notes	2.95%	January 15, 2020	\$ 1,000
Generation	Continental Wind Nonrecourse Debt ^(b)	6.00%	February 28, 2033	18
Generation	Antelope Valley DOE Nonrecourse Debt ^{(b)(c)}	2.29% - 3.56%	January 5, 2037	5
Generation	Renewable Power Generation Nonrecourse Debt ^(b)	4.11%	March 31, 2035	3
ACE	Transition Bonds	5.55%	October 20, 2023	5

(a) On April 1, 2020, Generation repurchased \$188 million of tax-exempt bonds.

(b) See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of nonrecourse debt.

(c) Antelope Valley's nonrecourse debt of approximately \$479 million was reclassified as current in Exelon's and Generation's Consolidated Balance Sheets in the first quarter of 2019 and continues to be classified as current as of March 31, 2020 as a result of the PG&E bankruptcy filing on January 29, 2019. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Dividends

Quarterly dividends declared by the Exelon Board of Directors during the three months ended March 31, 2020 and for the second quarter of 2020 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share ^(a)
First Quarter 2020	January 28, 2020	February 20, 2020	March 10, 2020	\$ 0.3825
Second Quarter 2020	April 28, 2020	May 15, 2020	June 10, 2020	\$ 0.3825

(a) Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020.

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 \$5.7 billion was available to support additional commercial paper as of March 31, 2020, and of which no financial institution has more than 7% of the aggregate commitments for the Registrants. In March of 2020, Generation borrowed \$1.5 billion on its revolving credit facility to refinance commercial paper, which was repaid on April 3, 2020. The \$1.5 billion borrowing reduced the available amount under the credit facilities as of March 31, 2020. The Registrants had access to the commercial paper markets and had availability under their revolving credit facilities during the first quarter of 2020 to fund their short-term liquidity needs. 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. Despite disruptions in the financial markets due to COVID-19, the Registrants have been able to fund their liquidity needs to date. See PART I. ITEM

1A. RISK FACTORS of the Exelon 2019 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, 2020, it would have been required to provide incremental collateral of \$1.5 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 \$2.4 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, 2020 and available credit facility capacity prior to any incremental collateral at March 31, 2020:

	PJM Credit Policy Collateral	Other Incremental Collateral Required ^(a)	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	\$ 12	\$ —	\$ 998
PECO	—	33	600
BGE	11	34	459
Pepco	11	—	300
DPL	4	12	246
ACE	—	—	246

(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 16 — Debt and Credit Agreements of the Exelon 2019 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 Registrants' credit ratings did not change in the first quarter of 2020.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of March 31, 2020, are presented in the following table:

Exelon Intercompany Money Pool	During the Three Months Ended March 31, 2020		As of March 31, 2020
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Contributed (Borrowed)			
Exelon Corporate	\$ 452	\$ —	\$ 19
Generation	254	(298)	254
PECO	292	—	90
BSC	25	(563)	(404)
PHI Corporate	—	(22)	(19)
PCI	60	—	60

PHI Intercompany Money Pool	During the Three Months Ended March 31, 2020		As of March 31, 2020
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Contributed (Borrowed)			
Pepco	\$ 166	\$ —	\$ 114
DPL	—	(95)	(37)
ACE	—	(84)	(77)

Shelf Registration Statements

Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE 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

ComEd, PECO, BGE, Pepco, DPL and ACE are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	As of March 31, 2020					
	Short-term Financing Authority ^(a)			Remaining Long-term Financing Authority ^(a)		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd	FERC	December 31, 2021	\$ 2,500	ICC	February 1, 2023	\$ 893
PECO	FERC	December 31, 2021	1,500	PAPUC	December 31, 2021	1,575
BGE ^(b)	FERC	December 31, 2021	700	MDPSC	N/A	—
Pepco	FERC	December 31, 2021	500	MDPSC / DCPSC	December 31, 2022	1,050
DPL	FERC	December 31, 2021	500	MDPSC / DPSC	December 31, 2022	475
ACE	NJBPU	December 31, 2021	350	NJBPU	December 31, 2020	200

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

(b) On April 23, 2020, BGE received approval from the MDPSC for \$1.5 billion long-term financing authority.

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 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2019 Form 10-K.

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 2019 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 2019 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures 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 2019 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 2020 through 2022.

As of March 31, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York and ERCOT reportable segments is 89%-92% and 70%-73% for 2020 and 2021, respectively. 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, 2020 market conditions and hedged position would be a decrease in pre-tax net income of approximately \$55 million and \$239 million, respectively, for 2020 and 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 2020 through 2024 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 2019 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, 2019 to March 31, 2020. 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, 2020 and December 31, 2019.

	Exelon	Generation	ComEd
Total mark-to-market energy contract net assets (liabilities) at December 31, 2019 ^(a)	\$ 567	\$ 868	\$ (301)
Total change in fair value during 2020 of contracts recorded in results of operations	(117)	(117)	—
Reclassification to realized at settlement of contracts recorded in results of operations	242	242	—
Changes in fair value — recorded through regulatory assets ^(b)	(13)	—	(13)
Changes in allocated collateral	(40)	(40)	—
Net option premium paid	38	38	—
Option premium amortization	(6)	(6)	—
Upfront payments and amortizations ^(c)	(65)	(65)	—
Total mark-to-market energy contract net assets (liabilities) at March 31, 2020 ^(a)	<u>\$ 606</u>	<u>\$ 920</u>	<u>\$ (314)</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, 2020, ComEd recorded a regulatory asset of \$314 million related to its mark-to-market derivative liabilities with unaffiliated suppliers. For the three months ended March 31, 2020, ComEd recorded \$23 million of decreases 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.

(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
	2020	2021	2022	2023	2024	2025 and Beyond	
Normal Operations, Commodity derivative contracts ^{(a)(b)} :							
Actively quoted prices (Level 1)	\$ (106)	\$ (35)	\$ (23)	\$ 5	\$ 9	\$ —	\$ (150)
Prices provided by external sources (Level 2)	127	38	33	10	—	—	208
Prices based on model or other valuation methods (Level 3) ^(c)	315	279	93	(1)	(18)	(120)	548
Total	\$ 336	\$ 282	\$ 103	\$ 14	\$ (9)	\$ (120)	\$ 606

- (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 \$889 million at March 31, 2020.
- (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
	2020	2021	2022	2023	2024	2025 and Beyond	
Normal Operations, Commodity derivative contracts ^{(a)(b)} :							
Actively quoted prices (Level 1)	\$ (106)	\$ (35)	\$ (23)	\$ 5	\$ 9	\$ —	\$ (150)
Prices provided by external sources (Level 2)	127	38	33	10	—	—	208
Prices based on model or other valuation methods (Level 3)	342	309	123	28	11	49	862
Total	\$ 363	\$ 312	\$ 133	\$ 43	\$ 20	\$ 49	\$ 920

- (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 \$889 million at March 31, 2020.

ComEd

	Maturities Within						Total Fair Value
	2020	2021	2022	2023	2024	2025 and Beyond	
Commodity derivative contracts ^(a) :							
Prices based on model or other valuation methods (Level 3) ^(a)	\$ (27)	\$ (30)	\$ (30)	\$ (29)	\$ (29)	\$ (169)	\$ (314)

- (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, 2020. 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 figures 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, 2020	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	\$ 915	\$ 22	\$ 893	\$ —	\$ —
Non-investment grade	60	49	11		
No external ratings					
Internally rated — investment grade	228	1	227		
Internally rated — non-investment grade	157	22	135		
Total	<u>\$ 1,360</u>	<u>\$ 94</u>	<u>\$ 1,266</u>	<u>\$ —</u>	<u>\$ —</u>

Maturity of Credit Risk Exposure

Rating as of March 31, 2020	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	\$ 830	\$ 68	\$ 17	\$ 915
Non-investment grade	58	2	—	60
No external ratings				
Internally rated — investment grade	163	35	30	228
Internally rated — non-investment grade	148	4	5	157
Total	<u>\$ 1,199</u>	<u>\$ 109</u>	<u>\$ 52</u>	<u>\$ 1,360</u>

Net Credit Exposure by Type of Counterparty	As of March 31, 2020
Financial institutions	\$ 18
Investor-owned utilities, marketers, power producers	983
Energy cooperatives and municipalities	224
Other	41
Total	<u>\$ 1,266</u>

(a) As of March 31, 2020, credit collateral held from counterparties where Generation had credit exposure included \$29 million of cash and \$65 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 2019 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 16 — Debt and Credit Agreements of Exelon's 2019 Annual Report on Form 10-K for additional information.

Utility Registrants

As of March 31, 2020, 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 approximately a \$1 million decrease in Exelon pre-tax income for the three months ended March 31, 2020. 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, 2020, 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 10% increase in interest rates and decrease in equity prices would result in a \$514 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 2020, 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, 2020, 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 2020 that materially affected, or are reasonably likely to materially affect, any of the Registrants' internal control over financial reporting, including no changes resulting from COVID-19. See Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Executive Overview for additional information on COVID-19.

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 2019 Form 10-K and (b) Notes 2 — 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 Exelon

At March 31, 2020, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2019 Form 10-K in ITEM 1A. RISK FACTORS, except for the following risk factor, which was added.

Our Results Could be Negatively Affected by the Impacts of COVID-19 (All Registrants).

The Registrants are monitoring the global outbreak of COVID-19 and have taken steps to mitigate the potential risks posed by its spread. This is a rapidly evolving situation that could lead to extended disruption of economic activity in the Registrants' respective markets. COVID-19 could negatively affect the Registrants' ability to operate their respective generating and transmission and distribution assets, their ability to access capital markets, and results of operations. The Registrants cannot predict the extent of the impacts of COVID-19, which will depend on future developments and which are highly uncertain at this time. See Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Executive Overview for additional information on COVID-19.

Item 4. Mine Safety Disclosures

All Registrants

Not applicable to the Registrants.

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	Supplemental Indenture dated as of February 10, 2020 from ComEd to BNY Mellon Trust Company of Illinois, as trustee, and D. G. Donovan, as co-trustee (File No 1-1839, Form 8-K dated February 25, 2020, Exhibit 4.1).
4.2	Supplemental Indenture, dated as of February 12, 2020, with respect to the Mortgage and Deed of Trust, dated July 1, 1936 (File No 1-01072, Form 8-K dated February 25, 2020, Exhibit 4.2).
4.3	Fourth Supplemental Indenture, dated as of April 1, 2020, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee (File No. 1-16169, Form 8-K dated April 1, 2020, Exhibit 4.2).
4.4*	One Hundred and Twenty-Fourth Supplemental Indenture, dated January 1, 2020, between Delmarva Power & Light Company and the Bank of New York Mellon, as trustee.
10.1	Exelon Corporation 2020 Long-Term Incentive Plan (File No. 1-16169, Exelon Proxy Statement dated March 18, 2020, Appendix A).
10.2	Receivables Purchase Agreement, dated as of April 8, 2020, 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. 85496, Form 8-K dated April 9, 2020, 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

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, 2020 filed by the following officers for the following companies:

31-1	— Filed by Christopher M. Crane for Exelon Corporation
31-2	— Filed by Joseph Nigro for Exelon Corporation
31-3	— Filed by Kenneth W. Cornew 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

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, 2020 filed by the following officers for the following companies:

32-1	— Filed by Christopher M. Crane for Exelon Corporation
32-2	— Filed by Joseph Nigro for Exelon Corporation
32-3	— Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	— Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	— Filed by Joseph Dominguez for Commonwealth Edison Company
32-6	— Filed by Jeanne M. Jones for Commonwealth Edison Company
32-7	— Filed by Michael A. Innocenzo for PECO Energy Company
32-8	— Filed by Robert J. Stefani for PECO Energy Company
32-9	— Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
32-10	— Filed by David M. Vahos for Baltimore Gas and Electric Company
32-11	— Filed by David M. Velazquez for Pepco Holdings LLC
32-12	— Filed by Phillip S. Barnett for Pepco Holdings LLC
32-13	— Filed by David M. Velazquez for Potomac Electric Power Company
32-14	— Filed by Phillip S. Barnett for Potomac Electric Power Company
32-15	— Filed by David M. Velazquez for Delmarva Power & Light Company
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

<u> /s/ CHRISTOPHER M. CRANE </u> Christopher M. Crane President and Chief Executive Officer (Principal Executive Officer) and Director	<u> /s/ JOSEPH NIGRO </u> Joseph Nigro Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
<u> /s/ FABIAN E. SOUZA </u> Fabian E. Souza Senior Vice President and Corporate Controller (Principal Accounting Officer)	

May 8, 2020

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/ KENNETH W. CORNEW

Kenneth W. Cornew

President and Chief Executive Officer
(Principal Executive Officer)

/s/ MATTHEW N. BAUER

Matthew N. Bauer

Vice President and Controller
(Principal Accounting Officer)

/s/ BRYAN P. WRIGHT

Bryan P. Wright

Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

May 8, 2020

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/ GERALD J. KOZEL

Gerald J. Kozel

Vice President and Controller
(Principal Accounting Officer)

May 8, 2020

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 and 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/ SCOTT A. BAILEY

Scott A. Bailey

Vice President and Controller
(Principal Accounting Officer)

May 8, 2020

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 8, 2020

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 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 8, 2020

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 8, 2020

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 8, 2020

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 8, 2020

**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

May 7, 2020

Date

My Commission expires _____