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

FORM 10-K

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

For the Fiscal Year Ended December 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

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

Title of Each Class

COMMONWEALTH EDISON COMPANY:

Common Stock Purchase Warrants (1971 Warrants and Series B Warrants)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☒	No ☐
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒
Pepco Holdings LLC	Yes ☐	No ☒
Potomac Electric Power Company	Yes ☐	No ☒
Delmarva Power & Light Company	Yes ☐	No ☒
Atlantic City Electric Company	Yes ☐	No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒
Pepco Holdings LLC	Yes ☐	No ☒
Potomac Electric Power Company	Yes ☐	No ☒
Delmarva Power & Light Company	Yes ☐	No ☒
Atlantic City Electric Company	Yes ☐	No ☒

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

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

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

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

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

Indicate by check mark whether the registrant has filed a report on and attestation to its management’s assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act by the registered public accounting firm that prepared or issued its audit report. ☒

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

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2020 was as follows:

Exelon Corporation Common Stock, without par value	$35,402,501,369
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company	None
Delmarva Power & Light Company	None
Atlantic City Electric Company	None

The number of shares outstanding of each registrant’s common stock as of January 31, 2021 was as follows:

Exelon Corporation Common Stock, without par value	976,337,799
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,370
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

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2020 Annual Meeting of Shareholders and the Commonwealth Edison Company 2020 Information Statement are incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL, and ACE, collectively
Legacy PHI	PHI, Pepco, DPL, ACE, PES, and PCI, collectively
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
Antelope Valley	Antelope Valley Solar Ranch One
BondCo	RSB BondCo LLC
BSC	Exelon Business Services Company, LLC
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
EEDC	Exelon Energy Delivery Company, LLC
EGR IV	ExGen Renewables IV, LLC
EGRP	ExGen Renewables Partners, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
Exelon Transmission Company	Exelon Transmission Company, LLC
FitzPatrick	James A. FitzPatrick nuclear generating station
Ginna	R. E. Ginna nuclear generating station
NER	NewEnergy Receivables LLC
PCI	Potomac Capital Investment Corporation and its subsidiaries
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PHI Corporate	PHI in its corporate capacity as a holding company
PHISCO	PHI Service Company
RPG	Renewable Power Generation
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility
UII	Unicom Investments, Inc.

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
ABO	Accumulated Benefit Obligation
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income (Loss)
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
ASA	Asset Sale Agreement
BGS	Basic Generation Service
Brookfield Renewable	Brookfield Renewable Partners, L.P.
CAISO	California ISO
CBAs	Collective Bargaining Agreements
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
CES	Clean Energy Standard
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CODM	Chief Operating Decision Maker
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE during the Predecessor periods
DC PLUG	District of Columbia Power Line Undergrounding Initiative
DCPSC	District of Columbia Public Service Commission
DOE	United States Department of Energy
DOEE	Department of Energy & Environment
DOJ	United States Department of Justice
DPP	Deferred Purchase Price
DPSC	Delaware Public Service Commission
DSP	Default Service Provider
EDF	Electricite de France SA and its subsidiaries
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ERP	Enterprise Resource Program
FASB	Financial Accounting Standards Board
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FRR	Fixed Resource Requirement
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GSA	Generation Supply Adjustment

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

GWh	Gigawatt hour
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
IIP	Infrastructure Investment Program
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
NYISO	New York ISO
kV	Kilovolt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LLRW	Low-Level Radioactive Waste
LNG	Liquefied Natural Gas
LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Standards
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
N/A	Not applicable
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOSA	Nuclear Operating Services Agreement
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchase Normal Sale scope exception
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PCB	Polychlorinated Biphenyl
PGC	Purchased Gas Cost Clause
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
PP&E	Property, Plant, and Equipment
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RNF	Revenue Net of Purchased Power and Fuel Expense
ROE	Return on equity
ROU	Right-of-use
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SGIG	Smart Grid Investment Grant from DOE
SNF	Spent Nuclear Fuel
SOA	Society of Actuaries
SOS	Standard Offer Service
SPP	Southwest Power Pool
SSA	Social Security Administration
TCJA	Tax Cuts and Jobs Act
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses, and fees
Transition Bonds	Transition Bonds issued by ACE Funding
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
ZEC	Zero Emission Credit
ZES	Zero Emission Standard

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties including, among others, those related to the timing, manner, tax-free nature and expected benefits associated with the potential separation of Exelon’s competitive power generation and customer-facing energy business from its six regulated electric and gas utilities. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic and financial performance, are intended to identify such forward-looking statements.

The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, including those factors discussed with respect to the Registrants discussed 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, (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 19, Commitments and Contingencies, and (d) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements, and other information that the Registrants file electronically with the SEC. These documents are also available to the public from commercial document retrieval services and the Registrants’ website at www.exeloncorp.com. Information contained on the Registrants’ website shall not be deemed incorporated into, or to be a part of, this Report.

PART I

ITEM 1.

General

Corporate Structure and Business and Other Information

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	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments Pepco, DPL, and ACE	Service Territories of Pepco, DPL, and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity	District of Columbia and Major portions of Montgomery and Prince George's Counties, Maryland
	Transmission and distribution of electricity to retail customers	
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies with the resources necessary to best serve customers and sustain long-term investment and operating excellence. The separation gives each company the financial and strategic independence to focus on its specific customer needs, while executing its core business strategy. See Note 26 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information.

Business Services

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.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Constellation sells electricity and natural gas, including renewable energy, in competitive energy markets to both wholesale and retail customers. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Generation's fleet also provides geographic and supply source diversity. Generation’s customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation’s customer-facing activities foster development and delivery of other innovative energy-related products and services for its customers.

Generation is a public utility under the Federal Power Act and is subject to FERC’s exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity, and ancillary services to ensure that such sales are just and reasonable. FERC’s jurisdiction over ratemaking includes the authority to suspend the market-based rates of utilities and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. FERC has approved PJM, MISO, ISO-NE, and SPP as RTOs and CAISO and NYISO as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX, and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC.

Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional, and local agencies, including the NRC, and Federal and state environmental protection agencies. Additionally, Generation is subject to NERC mandatory reliability standards, which protect the nation’s bulk power system against potential disruptions from cyber and physical security breaches.

Generating Resources

At December 31, 2020, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets[(a)(b)]	
Nuclear	18,880
Fossil (primarily natural gas and oil)	9,340
Renewable[(c)]	3,051
Owned generation assets	31,271
Contracted generation[(d)]	3,966
Total generating resources	35,237

(a) See “Fuel” for sources of fuels used in electric generation.
(b) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES—Generation for additional information.
(c) Includes wind, hydroelectric, solar, and biomass generation.
(d) Electric supply procured under site specific agreements.

Generation has five reportable segments, as described in the table below, representing the different geographical areas in which Generation’s owned generating resources are located and Generation's customer-facing activities are conducted.

Segment	Net Generation Capacity (MW)[(a)]	% of Net Generation Capacity	Geographical Area
Mid-Atlantic	9,729	31 %	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	11,911	38 %	Western half of PJM and the United States footprint of MISO, excluding MISO’s Southern Region
New York	1,971	6 %	NYISO
ERCOT	3,623	12 %	Electric Reliability Council of Texas
Other Power Regions	4,037	13 %	New England, South, West, and Canada
Total	31,271	100 %	

(a) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES—Generation for additional information.

Nuclear Facilities

Generation has ownership interests in thirteen nuclear generating stations currently in service, consisting of 23 units with an aggregate of 18,880 MW of capacity. These stations include FitzPatrick located in Scriba, New York, which was acquired on March 31, 2017 and exclude TMI located in Middletown, Pennsylvania, which permanently ceased generation operations on September 20, 2019 and Oyster Creek located in Forked River, New Jersey, which permanently ceased generation operations on September 17, 2018 and was subsequently sold to Holtec International (Holtec) on July 1, 2019. Generation wholly owns all of its nuclear generating stations, except for undivided ownership interests in three jointly-owned nuclear stations: Quad Cities (75% ownership), Peach Bottom (50% ownership), and Salem (42.59% ownership), which are consolidated in Exelon’s and Generation's financial statements relative to its proportionate ownership interest in each unit, and a 50.01% membership interest in CENG, a joint venture with EDF, which wholly owns the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to an 82% undivided ownership interest in Nine Mile Point Unit 2. CENG is 100% consolidated in Exelon's and Generation's financial statements.

Generation and EDF entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has an option to sell its 49.99% equity interest in CENG to Generation. The put option became exercisable on January 1, 2016 and may be exercised any time until June 30, 2022. On November 20, 2019, Generation received notice of EDF's intention to exercise the put option and sell its ownership share 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 and the FERC. The FERC approval was obtained on July 30, 2020. From the date the put was exercised, the process and regulatory approvals could take one to two years to complete.

See ITEM 2. PROPERTIES for additional information on Generation's nuclear facilities, Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the disposition of Oyster Creek, and Note 23 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the CENG consolidation.

Generation's nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2020, 2019, and 2018 electric supply (in GWh) generated from the nuclear generating facilities was 62%, 64%, and 68%, respectively, of Generation's total electric supply, which also includes fossil, hydroelectric, and renewable generation and electric supply purchased for resale. Generation's wholesale and retail power marketing activities are, in part, supplied by the output from the nuclear generating stations. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information of Generation's electric supply sources.

Nuclear Operations

Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation's results of operations. Generation's operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

Generation manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's wholesale and retail power marketing activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations. During 2020, 2019, and 2018, the nuclear generating facilities operated by Generation, achieved capacity factors of 95.4%, 95.7%, and 94.6%, respectively, at ownership percentage.

In addition to the maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation also has extensive safety systems in place to protect the plant, personnel, and surrounding area in the unlikely event of an accident or other incident.

Regulation of Nuclear Power Generation

Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security, and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results and communicates its assessment on a semi-annual basis. All nuclear generating stations operated by Generation are categorized by the NRC in the Licensee Response Column, which is the highest of five performance bands. The NRC may modify, suspend, or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures and/or operating costs for nuclear generating facilities.

Licenses

Generation has original 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals from the NRC for all its nuclear units except Clinton. PSEG has received 20-year operating license renewals for Salem Units 1 and 2. Peach Bottom has received a second 20-year license renewal from the NRC for Units 2 and 3. On August 27, 2020, Generation announced that it intends to permanently cease generation operations at Byron in September 2021 and at Dresden in November 2021. See Note 7 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

The following table summarizes the current license expiration dates for Generation's operating nuclear facilities in service:

Station	**Unit**	**In-Service Date**[(a)]	**Current License Expiration**
Braidwood	1	1988	2046
	2	1988	2047
Byron	1	1985	2044
	2	1987	2046
Calvert Cliffs	1	1975	2034
	2	1977	2036
Clinton[(b)]	1	1987	2027
Dresden	2	1970	2029
	3	1971	2031
FitzPatrick	1	1974	2034
LaSalle	1	1984	2042
	2	1984	2043
Limerick	1	1986	2044
	2	1990	2049
Nine Mile Point	1	1969	2029
	2	1988	2046
Peach Bottom	2	1974	2053
	3	1974	2054
Quad Cities	1	1973	2032
	2	1973	2032
Ginna	1	1970	2029
Salem	1	1977	2036
	2	1981	2040

(a) Denotes year in which nuclear unit began commercial operations.

(b) Although timing has been delayed, Generation currently plans to seek license renewal for Clinton and has notified the NRC that any license renewal application would not be filed until the first quarter of 2024. In 2019, the NRC approved a change of the operating license expiration for Clinton from 2026 to 2027.

The operating license renewal process takes approximately four to five years from the commencement of the renewal process, which includes approximately two years for Generation to develop the application and approximately two years for the NRC to review the application. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the first renewal of the operating licenses for all of Generation's operating nuclear generating stations except for Clinton, Peach Bottom, Byron, and Dresden. Clinton depreciation provisions are based on an estimated useful life of 2027 which is the last year of the Illinois ZES. Peach Bottom depreciation provisions are based on estimated useful life of 2053 and 2054 for Unit 2 and Unit 3, respectively, which reflects the second renewal of its operating licenses. Byron and Dresden depreciation provisions are based on the announced shutdown dates of September 2021 and November 2021, respectively. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Illinois ZES and Note 7 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information on early retirements.

Nuclear Waste Storage and Disposal

There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities on-site in storage pools or in dry cask storage facilities. Since Generation’s SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2020, Generation had approximately 87,100 SNF assemblies (21,600 tons) stored on site in SNF pools or dry cask storage which includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party, and TMI, which is no longer operational. See the Decommissioning section below for additional information regarding Zion Station. All currently operating Generation-owned nuclear sites have on-site dry cask storage. TMI's on-site dry cask storage is projected to be in operation in 2021. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation’s sites through the end of the license renewal periods and through decommissioning.

For a discussion of matters associated with Generation’s contracts with the DOE for the disposal of SNF, see Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site and none is anticipated to be operational for the next ten years.

Generation ships its Class A LLRW, which represents 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina, which have enough storage capacity to store all Class A LLRW for the life of all stations in Generation's nuclear fleet. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Salem), and Connecticut.

Generation utilizes on-site storage capacity at all its stations to store and stage for shipping Class B and Class C LLRW. Generation has a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at each station as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from Generation’s nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), Generation will still be required to utilize on-site storage at its stations for Class B and Class C LLRW. Generation currently has enough storage capacity to store all Class B and Class C LLRW for the life of all stations in Generation’s nuclear fleet. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize on-site storage and cost impacts.

Nuclear Insurance

Generation is subject to liability, property damage, and other risks associated with major incidents at all of its nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See “Nuclear Insurance” within Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

For information regarding property insurance, see ITEM 2. PROPERTIES — Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon’s and Generation’s future financial statements.

Decommissioning

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. The ultimate decommissioning obligation will be funded by the NDT funds. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF

OPERATIONS — Exelon Corporation, Liquidity and Capital Resources; ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations, and Nuclear Decommissioning Trust Fund Investments; and Note 3 — Regulatory Matters, Note 2 — Mergers, Acquisitions, and Dispositions, Note 18 — Fair Value of Financial Assets and Liabilities, and Note 10 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation’s NDT funds and its decommissioning obligations.

Oyster Creek Decommissioning. On July 1, 2019, Generation completed the sale with Holtec and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC (OCEP), of Oyster Creek under which Holtec has assumed the responsibility for decommissioning. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Zion Station Decommissioning. On September 1, 2010, Generation completed an ASA with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station. See Note 10 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

Fossil and Renewable Facilities (including Hydroelectric)

Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) Wyman; (2) certain wind project entities and a biomass project entity with minority interest owners; and (3) EGRP which is owned 49% by another owner. See Note 23 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding EGRP which is a VIE. Generation’s fossil and renewable generating stations are all operated by Generation, with the exception of Wyman, which is operated by a third party. In 2020, 2019, and 2018, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 9%, 11%, and 11%, respectively, of Generation’s total electric supply. The majority of this output was dispatched to support Generation’s wholesale and retail power marketing activities. On December 8, 2020, Generation entered into an agreement to sell a significant portion of Generation's solar business. See ITEM 2. PROPERTIES for additional information regarding Generation's electric generating facilities and Note 2 - Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the sale of Generation's solar business.

Licenses

Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid, which include Generation's Conowingo Hydroelectric Project (Conowingo) and Muddy Run Pumped Storage Facility Project (Muddy Run). Muddy Run's license expires on December 1, 2055. On August 29, 2012, Generation submitted a hydroelectric license application to the FERC for a new license for Conowingo. Based on the FERC procedural schedule, the FERC licensing process for Conowingo was not completed prior to the expiration of the plant’s license on September 1, 2014. As a result, on September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. The annual license renews automatically absent any further FERC action. The stations are currently being depreciated over their estimated useful lives, which include actual and anticipated license renewal periods. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on Conowingo.

Insurance

Generation maintains business interruption insurance for its renewable projects, but not for its fossil and hydroelectric operations unless required by contract or financing agreements. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on financing agreements. Generation maintains both property damage and liability insurance. For property damage and liability claims for these operations, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon’s and Generation’s future financial conditions and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES — Generation.

Contracted Generation

In addition to energy produced by owned generation assets, Generation sources electricity from plants it does not own under long-term contracts. The following tables summarize Generation's long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2020:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	8	2021 - 2032	183
Midwest	3	2021 - 2032	351
ERCOT	5	2021 - 2035	864
Other Power Regions	17	2021 - 2032	2,568
Total	33		3,966

	2021	2022	2023	2024	2025	Thereafter	Total
Capacity Expiring (MW)	884	304	103	101	461	2,113	3,966

Fuel

The following table shows sources of electric supply in GWh for 2020 and 2019:

	Source of Electric Supply	
	2020	2019
Nuclear[a]	175,085	181,326
Purchases — non-trading portfolio	79,972	70,939
Fossil (primarily natural gas and oil)	19,501	21,554
Renewable[b]	7,052	7,777
Total supply	281,610	281,596

(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). Nuclear generation for 2020 and 2019 includes physical volumes of 35,052 GWh and 35,745 GWh, respectively, for CENG.

(b) Includes wind, hydroelectric, solar, and biomass generating assets.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride, and the fabrication of fuel assemblies. Generation has inventory in various forms and does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment, or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation’s integrated business operations include physical delivery and marketing of power. Generation largely obtains physical power supply from its owned and contracted generation in multiple geographic regions. The commodity risks associated with the output from owned and contracted generation is managed using various commodity transactions including sales to customers. The main objective is to obtain low-cost energy supply to meet physical delivery obligations to both wholesale and retail customers. Generation sells electricity, natural gas, and other energy related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. Where necessary, Generation may also purchase transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs.

Price and Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation may also enter into transactions that are outside of this ratable sales plan. Generation is exposed to commodity price risk in 2021 and beyond for portions of its electricity portfolio that are unhedged. As of December 31, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% for 2021. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generation based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to the Utility Registrants to serve their retail load. A portion of Generation’s hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices. The risk management group and Exelon’s RMC monitor the financial risks of the wholesale and retail power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation’s efforts. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

Capital Expenditures

Generation’s business is capital intensive and requires significant investments primarily in nuclear fuel and energy generation assets. Generation’s estimated capital expenditures for 2021 include Generation's share of the investment in the co-owned Salem plant and the total capital expenditures for CENG. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources, for additional information regarding projected 2021 capital expenditures.

Utility Registrants

Merger with Pepco Holdings, Inc.

On March 23, 2016, Exelon completed the merger among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub), and PHI. As a result of that merger, Merger Sub was merged into PHI (the PHI merger) with PHI surviving as a wholly owned subsidiary of Exelon and EEDC, a wholly owned subsidiary of Exelon which also owns Exelon's interests in ComEd, PECO, and BGE (through a special purpose subsidiary in the case of BGE). Following the completion of the PHI merger, Exelon, and PHI completed a series of internal corporate organization restructuring transactions resulting in the transfer of PHI’s unregulated business interests to Exelon and Generation and the transfer of PHI, Pepco, DPL, and ACE to a special purpose subsidiary of EEDC.

Utility Operations

Service Territories and Franchise Agreements

The following table presents the size of service territories, populations of each service territory and the number of customers within each service territory for the Utility Registrants as of December 31, 2020:

	ComEd	PECO	BGE	Pepco	DPL	ACE
Service Territories (in square miles)						
Electric	11,400	2,100	2,300	640	5,400	2,800
Natural Gas	N/A	1,960	3,050	N/A	270	N/A
Total	11,400	2,100	3,250	640	5,400	2,800
Service Territory Population (in millions)						
Electric	9.6	4.0	3.0	2.4	1.5	1.1
Natural Gas	N/A	2.5	2.9	N/A	0.6	N/A
Total	9.6	4.0	3.1	2.4	1.5	1.1
Main City	Chicago	Philadelphia	Baltimore	District of Columbia	Wilmington	Atlantic City
Main City Population	2.7	1.6	0.6	0.7	0.1	0.1
Number of Customers (in millions)						
Electric	4.1	1.7	1.3	0.9	0.5	0.6
Natural Gas	N/A	0.5	0.7	N/A	0.1	N/A
Total	4.1	1.7	1.3	0.9	0.5	0.6

The Utility Registrants have the necessary authorizations to perform their current business of providing regulated electric and natural gas distribution services in the various municipalities and territories in which they now supply such services. These authorizations include charters, franchises, permits, and certificates of public convenience issued by local and state governments and state utility commissions. ComEd's, BGE's (gas), Pepco DC's, and ACE's rights are generally non-exclusive while PECO's, BGE's (electric), Pepco MD's, and DPL's rights are generally exclusive. Certain authorizations are perpetual while others have varying expiration dates. The Utility Registrants anticipate working with the appropriate governmental bodies to extend or replace the authorizations prior to their expirations.

Utility Regulations

State utility commissions regulate the Utility Registrants' electric and gas distribution rates and service, issuances of certain securities, and certain other aspects of the business. The following table outlines the state commissions responsible for utility oversight.

Registrant	Commission
ComEd	ICC
PECO	PAPUC
BGE	MDPSC
Pepco	DCPSC/MDPSC
DPL	DPSC/MDPSC
ACE	NJBPU

The Utility Registrants are public utilities under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of the utilities' business. The U.S. Department of Transportation also regulates pipeline safety and other areas of gas operations for PECO, BGE, and DPL. Additionally, the Utility Registrants are subject to NERC mandatory reliability standards, which protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

Seasonality Impacts on Delivery Volumes

The Utility Registrants' electric distribution volumes are generally higher during the summer and winter months when temperature extremes create demand for either summer cooling or winter heating. For PECO, BGE, and DPL, natural gas distribution volumes are generally higher during the winter months when cold temperatures create demand for winter heating.

ComEd, BGE, Pepco, and DPL Maryland have electric distribution decoupling mechanisms and BGE has a natural gas decoupling mechanism that eliminate the favorable and unfavorable impacts of weather and customer usage patterns on electric distribution and natural gas delivery volumes. As a result, ComEd's, BGE's, Pepco's, and DPL's Maryland electric distribution revenues and BGE's natural gas distribution revenues are not materially impacted by delivery volumes. PECO's and DPL's Delaware electric distribution revenues and natural gas distribution revenues and ACE's electric distribution revenues are impacted by delivery volumes.

Electric and Natural Gas Distribution Services

The Utility Registrants are allowed to recover reasonable costs and fair and prudent capital expenditures associated with electric and natural gas distribution services and earn a return on those capital expenditures, subject to commission approval. ComEd recovers costs through a performance-based rate formula. ComEd is required to file an update to the performance-based rate formula on an annual basis. PECO's, BGE's, and DPL's electric and gas distribution costs and Pepco's and ACE's electric distribution costs have generally been recovered through traditional rate case proceedings. However, the MDPSC and the DCPSC allow utilities to file multi-year rate plans. In certain instances, the Utility Registrants use specific recovery mechanisms as approved by their respective regulatory agencies.

ComEd, Pepco, and ACE customers have the choice to purchase electricity, and PECO, BGE, and DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. The Utility Registrants remain the distribution service providers for all customers and are obligated to deliver electricity and natural gas to customers in their respective service territories while charging a regulated rate for distribution service. In addition, the Utility Registrants also retain significant default service obligations to provide electricity to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier. PECO and BGE also retain significant default service obligations to provide natural gas to certain groups of customers in their respective service areas who do not choose a competitive natural gas supplier. For natural gas, DPL does not retain default service obligations for its residential customers.

For customers that choose to purchase electric generation or natural gas from competitive suppliers, the Utility Registrants act as the billing agent and therefore do not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from a Utility Registrant, the Utility Registrants are permitted to recover the electricity and natural gas procurement costs without mark-up and therefore record equal and offsetting amounts of Operating revenues and Purchased power and fuel expense related to the electricity and/or natural gas. As a result, fluctuations in electricity or natural gas sales and procurement costs have no impact on the Utility Registrants’ Net Income.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Results of Operations and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding electric and natural gas distribution services.

Procurement of Electricity and Natural Gas

The Utility Registrants' electric supply for its customers is primarily procured through contracts as required by their respective state commissions. The Utility Registrants procure electricity supply from various approved bidders, including Generation. RTO spot market purchases and sales are utilized to balance the utility electric load and supply as required. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on the Utility Registrants' Statements of Operations and Comprehensive Income.

PECO's, BGE's, and DPL's natural gas supplies are purchased from a number of suppliers for terms of up to three years. PECO, BGE, and DPL have annual firm supply and transportation contracts of 132,000 mmcf, 264,000 mmcf and 61,000 mmcf, respectively. In addition, to supplement gas supply at times of heavy winter demands and in the event of temporary emergencies, PECO, BGE, and DPL have available storage capacity from the following sources:

	Peak Natural Gas Sources (in mmcf)		
	LNG Facility	**Propane-Air Plant**	**Underground Storage Service Agreements** [a]
PECO	1,200	150	19,400
BGE	1,056	550	22,000
DPL	250	N/A	3,900

(a) Natural gas from underground storage represents approximately 28%, 20%, and 33% of PECO's, BGE's, and DPL's 2020-2021 heating season planned supplies, respectively.

PECO, BGE, and DPL have long-term interstate pipeline contracts and also participate in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between the utilities and customers. PECO, BGE, and DPL make these sales as part of a program to balance its supply and cost of natural gas. The off-system gas sales are not material to PECO, BGE, and DPL.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK, Commodity Price Risk (All Registrants), for additional information regarding Utility Registrants' contracts to procure electric supply and natural gas.

Energy Efficiency Programs

The Utility Registrants are generally allowed to recover costs associated with the energy efficiency and demand response programs they offer. Each commission approved program seeks to meet mandated electric consumption reduction targets and implement demand response measures to reduce peak demand. The programs are designed to meet standards required by each respective regulatory agency.

ComEd is allowed to earn a return on its energy efficiency costs. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Capital Investment

The Utility Registrants' businesses are capital intensive and require significant investments, primarily in electric transmission and distribution and natural gas transportation and distribution facilities, to ensure the adequate capacity, reliability, and efficiency of their systems. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources, for additional information regarding projected 2021 capital expenditures.

Transmission Services

Under FERC's open access transmission policy, the Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates approved by FERC. The Utility Registrants and their affiliates are required to comply with FERC's Standards of Conduct regulation governing the communication of non-public transmission information between the transmission owner's employees and wholesale merchant employees.

PJM is the regional grid operator and operates pursuant to FERC-approved tariffs. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff). PJM operates the PJM energy, capacity, and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the region. The Utility Registrants are members of PJM and provide regional transmission service pursuant to the PJM Tariff. The Utility Registrants and the other transmission owners in PJM have turned over control of certain of their transmission facilities to PJM, and their transmission systems are under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM transmission owners at rates based on the costs of transmission service.

The Utility Registrants' transmission rates are established based on a formula that was initially approved by FERC as shown below:

	Approval Date
ComEd	January 2008
PECO	December 2019
BGE	April 2006
Pepco	April 2006
DPL	April 2006
ACE	April 2006

Employees

The Registrants strive to create a workplace that is diverse, innovative, and safe for their employees. In order to provide the services and products that their customers expect, the Registrants must create the best teams. These teams must reflect the diversity of the communities that the Registrants serve. Therefore, the Registrants strive to attract highly qualified and diverse talent and routinely review their hiring and promotion practices to ensure they maintain equitable and bias free processes to neutralize any unconscious bias. The Registrants provide growth opportunities, competitive compensation and benefits, and a variety of training and development programs. The Registrants are committed to helping employees grow their skills and careers largely through numerous training opportunities in technical, safety and business acumen areas, mentorship programs, and continuous feedback and development discussions and evaluations. Employees are encouraged to thrive outside the workplace as well. The Registrants provide a full suite of wellness benefits targeted at supporting work-life balance, physical, mental and financial health, and industry-leading paid leave policies.

The Registrants conduct an employee engagement survey every other year to help identify their successes and areas where they can grow. The survey results are reviewed with senior management and the Exelon Board of Directors.

Diversity Metrics

The following tables show diversity metrics for all employees and management as of December 31, 2020:

Employees	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Female[(a) (b)]	7,993	2,492	1,517	727	765	1,281	366	154	121
People of Color[(b)]	9,298	2,083	2,432	890	1,067	1,748	898	194	139
Aged <30	3,268	1,363	625	279	273	425	183	85	62
Aged 30-50	17,119	6,712	3,491	1,292	1,694	2,207	756	466	369
Aged >50	11,953	4,407	2,138	1,227	1,172	1,594	517	385	219
Total Employees[(c)]	32,340	12,482	6,254	2,798	3,139	4,226	1,456	936	650

Management[(d)]	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Female[(a) (b)]	1,175	299	209	112	112	177	46	14	19
People of Color[(b)]	1,132	220	276	104	132	232	112	27	14
Aged <30	78	51	4	5	3	11	3	4	—
Aged 30-50	2,790	1,220	441	137	238	341	102	59	47
Aged >50	2,219	841	369	213	170	277	73	63	34
Within 10 years of retirement eligibility	2,936	1,113	487	250	235	370	95	82	46
Total Employees in Management[(c)]	5,087	2,112	814	355	411	629	178	126	81

(a) The Registrants are devoted to creating an environment that allows women to stay in the workforce, grow with the company, and move up the ranks, all with parity of pay. Exelon employs an independent third-party vendor to run regression analysis on all management positions each year. The analysis consistently shows that the Registrants have no systemic pay equity issues.
(b) This is based on self-disclosed information.
(c) Total employees represents the sum of the aged categories.
(d) Management is defined as executive/senior level officials and managers as well as all employees who have direct reports and supervisory responsibilities.

Turnover Rates

As turnover is inherent, management succession planning is performed and tracked for all executives and critical key manager positions. Management frequently reviews succession planning to ensure the Registrants are prepared when positions become available.

The table below shows the average turnover rate for all employees for the last three years of 2018 to 2020:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Retirement Age	4.13 %	4.80 %	3.69 %	2.64 %	3.64 %	4.31 %	4.90 %	3.70 %	3.37 %
Voluntary	2.87 %	3.88 %	1.37 %	1.55 %	1.37 %	2.18 %	2.51 %	1.10 %	1.21 %
Non-Voluntary	0.97 %	0.86 %	0.61 %	1.15 %	0.97 %	0.94 %	1.78 %	0.25 %	0.63 %

Collective Bargaining Agreements

Approximately 37% of Exelon's employees participate in CBAs. The following table presents employee information, including information about CBAs, as of December 31, 2020:

	Total Employees Covered by CBAs	Number of CBAs	CBAs New and Renewed in 2020[(a)]	Total Employees Under CBAs New and Renewed in 2020
Exelon	11,964	32	11	1,715
Generation	3,418	22	8	1,001
ComEd	3,476	2	1	71
PECO	1,350	2	—	—
BGE	1,423	1	—	—
PHI	2,203	5	2	626
Pepco	954	1	—	—
DPL	626	2	2	626
ACE	390	2	—	—

(a) Does not include CBAs that were extended in 2020 while negotiations are ongoing for renewal.

Environmental Regulation

General

The Registrants are subject to comprehensive and complex environmental legislation and regulation at the federal, state, and local levels, including requirements relating to climate change, air and water quality, solid and hazardous waste, and impacts on species and habitats.

The Exelon Board of Directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy & Chief Innovation and Sustainability Officer; the Senior Vice President, Competitive Market Policy; and the Vice President, Corporate Environmental Strategy, as well as senior management of the Registrants. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Exelon Board of Directors has delegated to its Generation Oversight Committee and the Corporate

Governance Committee the authority to oversee Exelon's compliance with health, environmental, and safety laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including Exelon's internal climate change and sustainability policies and programs, as discussed in further detail below. The respective Boards of the Utility Registrants oversee environmental, health, and safety issues related to these companies.

Climate Change Mitigation

Exelon supports comprehensive federal climate legislation, including a cap-and-trade program for GHG emissions that addresses the urgent need to substantially reduce national GHG emissions while providing appropriate protections for consumers, businesses, and the economy. In the absence of comprehensive federal legislation, Exelon supports EPA moving forward with meaningful regulation of GHG emissions under the Clean Air Act.

The Registrants currently are subject to, and may become subject to additional, federal and/or state legislation and/or regulations addressing GHG emissions. Generation produces electricity predominantly from low- and zero-carbon generating facilities (such as nuclear, hydroelectric, natural gas, wind, and solar PV) and neither owns nor operates any coal-fueled generating assets. Generation's natural gas and biomass fired generating plants produce GHG emissions, most notably CO2. However, Generation's owned-asset emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry.

Other GHG emission sources associated with the Utility Registrants include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF6) leakage from electric transmission and distribution operations, refrigerant leakage from chilling and cooling equipment, and fossil fuel combustion in motor vehicles. In addition, PECO, BGE, and DPL distribute natural gas and Generation sells natural gas at retail; and consumers' use of such natural gas produces GHG emissions.

International Climate Change Agreements. At the international level, the United States is a party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. Under the Agreement, which became effective on November 4, 2016, the parties committed to try to limit the global average temperature increase and to develop national GHG reduction commitments. On November 4, 2020, the United States formally withdrew from the Paris Agreement, retracting its commitment to reduce domestic GHG emissions by 26%-28% by 2025 compared with 2005 levels. However, on January 20, 2021, President Biden accepted the Paris Agreement, which resulted in the United States' formal re-entry on February 19, 2021. The Biden administration has announced its intent to pursue ambitious GHG reductions in the United States and internationally.

Federal Climate Change Legislation and Regulation. It is highly uncertain whether federal legislation to significantly reduce GHG emissions will be enacted in the near-term. If such legislation were adopted, it would likely increase the value of Exelon's low-carbon fleet even though Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. Continued inaction could negatively impact the value of Exelon's low-carbon fleet.

The Clean Power Plan and Affordable Clean Energy Rule. The EPA's 2015 Clean Power Plan (CPP) established regulations addressing carbon dioxide emissions from existing fossil-fired power plants under Clean Air Act Section 111(d). The CPP's carbon pollution limits could be met through changes to the electric generation system, including shifting generation from higher-emitting units to lower- or zero-emitting units, as well as the development of new or expanded zero-emissions generation. In July 2019, the EPA published its final Affordable Clean Energy rule, which repealed the CPP and replaced it with less stringent emissions guidelines for existing fossil-fired power plants based on heat rate improvement measures that could be achieved within the fence line of individual plants. Exelon, together with a coalition of other electric utilities, filed a lawsuit in the U.S. Court of Appeals for the D.C. Circuit on September 6, 2019, challenging the Affordable Clean Energy rule as unlawful. This lawsuit was consolidated with separate challenges to the Affordable Clean Energy rule filed by various states, non-governmental organizations, and business coalitions. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit held the Affordable Clean Energy Rule to be unlawful, vacated the rule, and remanded it to the EPA. The EPA has indicated it will promulgate new GHG limits for existing power plants in accordance with the U.S. Court of Appeals for the D.C. Circuit's order.

State Climate Change Legislation and Regulation. A number of states in which the Registrants operate have state and regional programs to reduce GHG emissions and renewable and other portfolio standards, which impact the power sector. See discussion below for additional information on renewable and other portfolio standards. As the nation’s largest generator of carbon-free electricity, Generation’s fleet supports these efforts to produce safe, reliable electricity with minimal GHGs.

Eleven northeast and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia) currently participate in the RGGI, which is in the process of strengthening its requirements. The program requires most fossil fuel-fired power plants in the region to hold allowances, purchased at auction, for each ton of CO2 emissions. Non-emitting resources do not have to purchase or hold these allowances. In October 2019, the Governor of Pennsylvania issued an Executive Order directing the PA DEP to begin a rulemaking process to allow Pennsylvania to join the RGGI, with the goal of reducing carbon emissions from the electricity sector. On November 7, 2020, the PA DEP proposed its rule.

Broader state programs impact other sectors as well, such as New York’s Climate Leadership and Community Protection Act, which establishes statewide emission limits; and Massachusetts’ Clean Energy and Climate Plan, which aims to reduce GHG emissions across all sectors through increased efficiency in buildings and vehicles, the electrification of vehicles and thermal conditioning in buildings, and the replacement of carbon intensive fuels with renewable energy sources.

While the Registrants cannot predict the nature of future regulations or how such regulations might impact future financial statements, Generation has a low emission portfolio, and GHG restrictions would likely benefit zero- and low-emission generating units relative to higher-emission fossil fuel-fired generating units.

In addition, Exelon facilities and operations are subject to the global impacts of climate change. Exelon believes its operations could be significantly affected by the physical risks of climate change. See ITEM 1A. RISK FACTORS for additional information.

Renewable and Clean Energy Standards

Thirty states and the District of Columbia, incorporating the vast majority of states where Exelon operates, have adopted some form of renewable or clean energy procurement requirement. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. The Utility Registrants comply with these various requirements through purchasing qualifying renewables, implementing efficiency programs, acquiring sufficient credits (e.g., RECs), paying an alternative compliance payment, and/or a combination of these compliance alternatives. The Utility Registrants are permitted to recover from retail customers the costs of complying with their state RPS requirements, including the procurement of RECs or other alternative energy resources. Illinois, New York, and New Jersey adopted standards targeted at preserving the zero-carbon attributes of certain nuclear-powered generating facilities. Generation owns multiple facilities participating in these programs within these states. Other states in which Exelon operates are considering similar programs.

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

Air Quality

Mercury and Air Toxics Standards (MATS). In 2011, the EPA signed a final rule, known as MATS, to reduce emissions of hazardous air pollutants from power plants. MATS requires coal-fired power plants to achieve high removal rates of mercury, acid gases, and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. In 2016, in response to a Supreme Court decision requiring the EPA to consider costs in determining whether it was appropriate and necessary to regulate power plant emissions of hazardous air pollutants, the EPA issued a supplemental finding that, after considering costs, it remained appropriate and necessary. On May 22, 2020, the EPA reversed course, publishing a final rule revoking the "appropriate and necessary" finding underpinning MATS. A coal mining company filed a lawsuit in the U.S. Court of Appeals for the D.C. Circuit seeking vacatur of MATS based on the EPA’s May 22, 2020 finding; on September 11, 2020, the U.S. Court of Appeals for the D.C. Circuit granted a motion by Exelon and two other entities to intervene in that lawsuit to defend MATS, and on September 28, 2020, the U.S. Court of Appeals for the D.C. Circuit issued an Executive Order holding this portion of the MATS litigation in abeyance. On July 21, 2020, Exelon and two other entities filed a lawsuit in the U.S. Court of Appeals for the D.C. Circuit challenging the EPA's May 22, 2020 rescission of the appropriate and necessary finding underpinning MATS. This portion of the case is also being held in abeyance in response to the DOJ's motion filed February 12, 2021. On January 20, 2021, President Biden issued an Executive Order directing the EPA to reconsider its May 22, 2020 recission by August 2021; the EPA will likely re-affirm the finding that it is appropriate and necessary to regulate power plant emissions of hazardous air pollutants. As a result, this litigation is likely to be rendered moot, and MATS will likely remain in place in the interim.

Water Quality

Under the federal Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the EPA or from the state environmental agency to which the permit program has been delegated, and permits must be renewed periodically. Certain of Exelon's facilities discharge stormwater, industrial wastewater, and/or cooling water into waterways and are therefore subject to these regulations and operate under NPDES permits.

Clean Water Act Section 316(b) is implemented through the NDPES program and requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. Generation's power generation facilities with cooling water intake systems are subject to the EPA's Section 316(b) regulations finalized in 2014; the regulation's requirements have been or will be addressed through renewal of these facilities' NPDES permits. Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the EPA's 2014 rule will have on the operation of its generating facilities and its financial statements. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility's economic viability could be called into question. However, the final rule does not mandate cooling towers and allows state permitting directors to require alternative, less costly technologies and/or operational measures, based on a site-specific assessment of the feasibility, costs, and benefits of available options.

On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers and allows Salem to continue to operate utilizing the existing cooling water system with certain required system modifications. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

Under Clean Water Act Section 404 and state laws and regulations, the Registrants may be required to obtain permits for projects involving dredge or fill activities in Waters of the United States.

Where Registrants' facilities are required to secure a federal license or permit for activities that may result in a discharge to covered waters, they may be required to obtain a state water quality certification under Clean Water Act section 401.

Generation is also subject to the jurisdiction of the Delaware River Basin Commission and the Susquehanna River Basin Commission, regional agencies that primarily regulate water usage.

Solid and Hazardous Waste and Environmental Remediation

CERCLA provides for response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances and authorizes the EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of hazardous waste at sites, many of which are listed by the EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight. Most states have also enacted statutes that contain provisions substantially similar to CERCLA. Such statutes apply in many states where the Registrants currently own or operate, or previously owned or operated, facilities, including Delaware, Illinois, Maryland, New Jersey, and Pennsylvania and the District of Columbia. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with these Federal and state environmental laws. Under these laws, the Registrants may be 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. The Registrants and their subsidiaries are, or could become in the future, parties to proceedings initiated by the EPA, state agencies, and/or other responsible parties under CERCLA and RCRA or similar state laws with respect to a number of sites or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

ComEd's and PECO's environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. BGE, ACE, Pepco, and DPL do not have material contingent liabilities relating to MGP sites. The amount to be expended in 2021 for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is estimated to be approximately $35 million which consists primarily of $30 million at ComEd.

As of December 31, 2020, the Registrants have established appropriate contingent liabilities for environmental remediation requirements. In addition, the Registrants may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental matters, remediation efforts, and related impacts to the Registrants' Consolidated Financial Statements.

Information about our Executive Officers as of February 24, 2021

Exelon

Name	Age	Position	Period
Crane, Christopher M.	62	Chief Executive Officer, Exelon;	2012 - Present
		President, Exelon	2008 - Present
Cornew, Kenneth W.	55	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
Butler, Calvin G.	51	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2019 - Present
		Chief Executive Officer, BGE	2014 - 2019
Dominguez, Joseph	58	Chief Executive Officer, ComEd	2018 - Present
		Executive Vice President, Governmental & Regulatory Affairs and Public Policy, Exelon	2015 - 2018
Glockner, David	60	Executive Vice President, Compliance and Audit, Exelon	2020 - Present
		Chief Compliance Officer, Citadel LLC	2017 - 2020
		Regional Director, U.S. Securities and Exchange Commission	2013 - 2017
Hanson, Bryan C.	55	Executive Vice President and Chief Generation Officer, Generation	2020 - Present
		President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Generation	2015 - 2020
Innocenzo, Michael A.	55	President and Chief Executive Officer, PECO	2018 - Present
		Senior Vice President and Chief Operations Officer, PECO	2012 - 2018
Khouzami, Carim V.	45	Chief Executive Officer, BGE	2019 - Present
		Senior Vice President, Chief Operating Officer, Exelon Utilities	2018 - 2019
		Senior Vice President, Chief Financial Officer, Exelon Utilities	2016 - 2018
		Senior Vice President, Chief Integration Officer, Exelon	2014 - 2016
Velazquez, David M.	61	President and Chief Executive Officer, PHI	2016 - Present
		President and Chief Executive Officer, Pepco, DPL, and ACE	2009 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
Von Hoene Jr., William A.	67	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present

Name	Age	Position	Period
Nigro, Joseph	56	Senior Executive Vice President and Chief Financial Officer, Exelon	2018 - Present
		Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - 2018
Souza, Fabian E.	50	Senior Vice President and Corporate Controller, Exelon	2018 - Present
		Senior Vice President and Deputy Controller, Exelon	2017 - 2018
		Vice President, Controller and Chief Accounting Officer, The AES Corporation	2015 - 2017

Generation

Name	Age	Position	Period
Crane, Christopher M.	62	Principle Executive Officer, Generation	2020 - Present
		Chief Executive Officer, Exelon;	2012 - Present
		President, Exelon	2008 - Present
Cornew, Kenneth W.	55	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and Chief Executive Officer, Generation	2013 - Present
Swahl, William	51	Senior Vice President, Generation; Chief Operating Officer, Exelon Power	2021 - Present
		Vice President, Generation; Vice President, Mid-Atlantic Operations, Exelon Power	2014 - 2020
Hanson, Bryan C.	55	Executive Vice President and Chief Generation Officer, Generation	2020 - Present
		President and Chief Nuclear Officer, Exelon Nuclear, Senior Vice President, Generation	2015 - 2020
McHugh, James	49	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2018 - Present
		Senior Vice President, Portfolio Management & Strategy, Constellation	2016 - 2018
		Vice President, Portfolio Management, Constellation	2012 - 2016
Rhoades, David	54	Senior Vice President, Generation; President and Chief Nuclear Officer, Exelon Nuclear	2020 - Present
		Chief Operating Officer, Fleet Operations, Exelon Nuclear	2015 - 2020
Wright, Bryan P.	54	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
Bauer, Matthew N.	44	Vice President and Controller, Generation	2016 - Present
		Vice President and Controller, BGE	2014 - 2016

ComEd

Name	Age	Position	Period
Dominguez, Joseph	58	Chief Executive Officer, ComEd	2018 - Present
		Executive Vice President, Governmental & Regulatory Affairs and Public Policy, Exelon	2015 - 2018
Donnelly, Terence R.	60	President and Chief Operating Officer, ComEd	2018 - Present
		Executive Vice President and Chief Operating Officer, ComEd	2012 - 2018
Jones, Jeanne M.	41	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2018 - Present
		Vice President, Finance, Exelon Nuclear	2014 - 2018
Park, Jane	48	Senior Vice President, Customer Operations, ComEd	2018 - Present
		Vice President, Regulatory Policy & Strategy, ComEd	2016 - 2018
		Director, Business Strategy & Technology, ComEd	2014 - 2016
Gomez, Veronica	51	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2017 - Present
		Vice President and Deputy General Counsel, Litigation, Exelon	2012 - 2017
Washington, Melissa	51	Senior Vice President, Governmental and External Affairs, ComEd	2019 - Present
		Vice President, Governmental and External Affairs, ComEd	2019 -2019
		Vice President, External Affairs and Large Customer Services, ComEd	2016 - 2019
		Vice President, Corporate Affairs, Exelon Business Services Company	2014 - 2016
Perez, David	51	Senior Vice President, Distribution Operations, ComEd	2019 - Present
		Vice President, Transmission and Substation, ComEd	2016 - 2019
		Vice President, Regional Operations, ComEd	2010 - 2016

PECO

Name	Age	Position	Period
Innocenzo, Michael A.	55	President and Chief Executive Officer, PECO	2018 - Present
		Senior Vice President and Chief Operations Officer, PECO	2012 - 2018
McDonald, John	63	Senior Vice President and Chief Operations Officer, PECO	2018 - Present
		Vice President, Integration, PHI	2016 - 2018
		Vice President, Technical Services	2006 - 2016
Stefani, Robert J.	47	Senior Vice President, Chief Financial Officer and Treasurer, PECO	2018 - Present
		Vice President, Corporate Development, Exelon	2015 - 2018
Murphy, Elizabeth A.	61	Senior Vice President, Governmental and External Affairs, PECO	2016 - Present
		Vice President, Governmental and External Affairs, PECO	2012 - 2016
Webster Jr., Richard G.	59	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
Williamson, Olufunmilayo	42	Senior Vice President, Customer Operations, PECO	2020 - Present
		Senior Vice President, Chief Commercial Risk Officer, Exelon	2017 - 2020
		Vice President, Commercial Risk Management, Exelon	2015 - 2017
Gay, Anthony	55	Vice President and General Counsel, PECO	2019 - Present
		Vice President, Governmental and External Affairs, PECO	2016 - 2019
		Associate General Counsel, Exelon	2010 - 2016

BGE

Name	Age	Position	Period
Khouzami, Carim V.	45	Chief Executive Officer, BGE	2019 - Present
		Senior Vice President, Chief Operating Officer, Exelon Utilities	2018 - 2019
		Senior Vice President, Chief Financial Officer, Exelon Utilities	2016 - 2018
		Senior Vice President, Chief Integration Officer, Exelon	2014 - 2016
Woerner, Stephen J.	53	President, BGE	2014 - Present
		Chief Operating Officer, BGE	2012 - Present
Vahos, David M.	48	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2016 - Present
		Vice President, Chief Financial Officer and Treasurer, BGE	2014 - 2016
Núñez, Alexander G.	49	Senior Vice President, Regulatory Affairs and Strategy, BGE	2020 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2016 - 2020
		Vice President, Governmental and External Affairs, BGE	2013 - 2016
Case, Mark D.	59	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
Oddoye, Rodney	44	Senior Vice President, Governmental and External Affairs, BGE	2020 - Present
		Vice President, Customer Operations, BGE	2018 - 2020
		Director, Northeast Regional Electric Operations, BGE	2016 - 2018
		Director, Financial Operations, BGE	2015 - 2016
Olivier, Tamla	48	Senior Vice President, Customer Operations, BGE	2020 - Present
		Senior Vice President, Constellation NewEnergy, Inc.	2016 - 2020
		VP, Human Resources, Exelon Business Services Company	2012 - 2016
Corse, John	60	Vice President and General Counsel, BGE	2018 - Present
		Associate General Counsel, Exelon	2012 - 2018

PHI, Pepco, DPL, and ACE

Name	Age	Position	Period
Velazquez, David M.	61	President and Chief Executive Officer, PHI	2016 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
		President and Chief Executive Officer, Pepco, DPL, and ACE	2009 - Present
Anthony, J. Tyler	56	Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE	2016 - Present
		Senior Vice President, Distribution Operations, ComEd	2010 - 2016
Barnett, Phillip S.	57	Senior Vice President, Chief Financial Officer and Treasurer, PHI, Pepco, DPL, and ACE	2018 - Present
		Senior Vice President and Chief Financial Officer, PECO	2007 - 2018
		Treasurer, PECO	2012 - 2018
Lavinson, Melissa	51	Senior Vice President, Governmental & External Affairs, PHI, Pepco, DPL, and ACE	2018 - Present
		Vice President, Federal Affairs and Policy and Chief Sustainability Officer, PG&E Corporation	2015 - 2018
Stark, Wendy E.	48	Senior Vice President, Legal and Regulatory Strategy and General Counsel, PHI, Pepco, DPL, and ACE	2019 - Present
		Vice President and General Counsel, PHI, Pepco, DPL, and ACE	2016 - 2018
		Deputy General Counsel, Pepco Holdings, Inc.	2012 - 2016
McGowan, Kevin M.	59	Vice President, Regulatory Policy and Strategy, PHI, Pepco, DPL, and ACE	2016 - Present
		Vice President, Regulatory Affairs, Pepco Holdings, Inc.	2012 - 2016
Dickens, Derrick	56	Senior Vice President, Customer Operations, PHI	2020 - Present
		Vice President, Technical Services, BGE	2016 - 2020
		Director, Advanced Meter Infrastructure, PECO	2012 - 2016
Humphrey, Marissa	41	Vice President, Regulatory Policy and Strategy, PHI, DPL, and ACE	2021 - Present
		Vice President Finance, Exelon Utilities	2019 - 2020
		Vice President, Finance, PHI	2016 - 2019

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a complex market and regulatory environment that involves significant risks, many of which are beyond that Registrant’s direct control. Such risks, which could negatively affect one or more of the Registrants’ consolidated financial statements, fall primarily under the categories below:

Market and Financial Factors primarily include:

- the price of fuels, in particular the price of natural gas, which affects power prices,
- the generation resources in the markets in which the Registrants operate,
- the demand for electricity, reliability of service, and affordability in the markets where the Registrants conduct their business,

- the ability of the Registrants to operate their respective generating and transmission and distribution assets, their ability to access capital markets, and the impacts on their results of operations due to the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19),
- the impacts of on-going competition, and
- emerging technologies and business models, including those related to climate change mitigation and transition to a low carbon economy.

Regulatory, Legislative, and Legal Factors primarily include changes to, and compliance with, the laws and regulations that govern:

- the design of power markets,
- ZEC programs,
- utility regulatory business models,
- environmental and climate policy, and
- tax policy.

Operational Factors primarily include:

- changes in the global climate could produce extreme weather events, which could put the Registrant's facilities at risk, and such changes could also affect the levels and patterns of demand for energy and related services,
- the safe, secure, and effective operation of Generation's nuclear facilities and the ability to effectively manage the associated decommissioning obligations,
- the ability of the Registrants to maintain the reliability, resiliency, and safety of their energy delivery systems, which could affect the operating costs of the Registrants and the opinions of their customers and regulators, and
- physical and cyber security risks for the Registrants as the owner-operators of generation, transmission, and distribution facilities and as participants in commodities trading.

Risks Related to the Planned Separation primarily include:

- the timing and conditions associated with required regulatory approvals, which may affect the costs to achieve the separation and its timing,
- challenges to achieving the benefits of separation, including maintaining investment grade credit ratings, and
- the risk that the separation could be treated as a taxable transaction to both Exelon and its shareholders.

There may be further risks and uncertainties that are not presently known or that are not currently believed by the Registrants to be material that could negatively affect its consolidated financial statements in the future.

Market and Financial Factors

Generation is exposed to price volatility associated with both the wholesale and retail power markets and the procurement of nuclear and fossil fuel (Exelon and Generation).

Generation is exposed to commodity price risk for the unhedged portion of its electricity generation supply portfolio. Generation's earnings and cash flows are therefore exposed to variability of spot and forward market prices in the markets in which it operates.

Price of Fuels. The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit.

Demand and Supply. The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs could each depress demand. In addition, in some markets, the supply of electricity could often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants such as Generation's nuclear plants. Conversely, new demand sources such as electrification of transportation could increase demand and change demand patterns.

Retail Competition. Generation’s retail operations compete for customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail operations to hedge generation output.

The impact of sustained low market prices or depressed demand and over-supply could be emphasized given Generation’s concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Generation’s ability to fund regulated utility growth for the benefit of customers, reduce debt and provide attractive shareholder returns. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Generation's financial statements primarily through accelerated depreciation and amortization expenses and one-time charges. See Note 7 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

Cost of Fuel. Generation depends on nuclear fuel and fossil fuels to operate most of its generating facilities. The supply markets for nuclear fuel, natural gas, and oil are subject to price fluctuations, availability restrictions, and counterparty default.

Market Designs. The wholesale markets vary from region to region with distinct rules, practices, and procedures. Changes in these market rules, problems with rule implementation, or failure of any of these markets could adversely affect Generation’s business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry (All Registrants).

Some of these technologies include, but are not limited to, further development or applications of technologies related to shale gas production, renewable energy technologies, energy efficiency, distributed generation, and energy storage devices. Such developments could affect the price of energy, levels of customer-owned generation, customer expectations, and current business models and make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could affect the Registrants’ consolidated financial statements through, among other things, reduced operating revenues, increased operating and maintenance expenses, increased capital expenditures, and potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors could decrease the value of NDT funds and employee benefit plan assets and could increase the related employee benefit plan obligations, which then could require significant additional funding (All Registrants).

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy could adversely affect the value of the investments held within Generation’s NDTs and Exelon’s employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below the Registrants’ projected return rates. A decline in the market value of the NDT fund investments could increase Generation’s funding requirements to decommission its nuclear plants. A decline in the market value of the pension and OPEB plan assets would increase the funding requirements associated with Exelon's pension and OPEB plan obligations. Additionally, Exelon's pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of the obligations related to the pension and OPEB plans. See Note 10 — Asset Retirement Obligations and Note 15 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants could be negatively affected by unstable capital and credit markets and increased volatility in commodity markets (All Registrants).

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs. Disruptions in the capital and credit markets in the United States or abroad could negatively affect the Registrants' ability to access the capital markets or draw on their respective bank revolving credit facilities. The banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. The inability to access capital markets or credit facilities, and longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives, or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, Generation's ability to hedge effectively its generation portfolio, changes to Generation's hedging strategy in order to reduce collateral posting requirements, or a reduction in dividend payments or other discretionary uses of cash. In addition, the Registrants have exposure to worldwide financial markets, including Europe, Canada, and Asia. Disruptions in these markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2020, approximately 23%, 19%, and 18% of the Registrants' available credit facilities were with European, Canadian, and Asian banks, respectively. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be negatively affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that could affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs (All Registrants).

Generation's business is subject to credit quality standards that could require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which could have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time depends on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation.

Generation has project-specific financing arrangements and must meet the requirements of various agreements relating to those financings. Failure to meet those arrangements could give rise to a project-specific financing default which, if not cured or waived, could result in the specific project being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have broad remedies, including rights to foreclose against the project assets and related collateral or to force the Exelon subsidiaries in the project-specific financings to enter into bankruptcy proceedings. The impact of bankruptcy could result in the impairment of certain project assets.

The Utility Registrants' operating agreements with PJM and PECO's, BGE's, and DPL's natural gas procurement contracts contain collateral provisions that are affected by their credit rating and market prices. If certain wholesale market conditions were to exist and the Utility Registrants were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the forms of letters of credit or cash, which could have a material adverse effect upon their remaining sources of liquidity. PJM collateral posting requirements will generally increase as market prices rise and decrease as market prices fall. Collateral posting requirements for PECO, BGE, and DPL, with respect to their natural gas supply contracts, will generally increase as forward market prices fall and decrease as forward market prices rise. If the Utility Registrants were downgraded, they could experience higher borrowing costs as a result of the downgrade. In addition, changes in ratings methodologies by the agencies could also have an adverse negative impact on the ratings of the Utility Registrants.

The Utility Registrants conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that the Utility Registrants are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate the Utility Registrants from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as “ring-fencing”) could help avoid or limit a downgrade in the credit ratings of the Utility Registrants in the event of a reduction in the credit rating of Exelon. Despite these ring-fencing measures, the credit ratings of the Utility Registrants could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of some or all of the Utility Registrants. A reduction in the credit rating of a Utility Registrant could have a material adverse effect on the Utility Registrant.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources — Credit Matters — Market Conditions and Security Ratings for additional information regarding the potential impacts of credit downgrades on the Registrants’ cash flows.

Generation’s risk management policies cannot fully eliminate the risk associated with its commodity trading activities (Exelon and Generation).

Generation’s asset-based power position as well as its power marketing, fuel procurement, and other commodity trading activities expose Generation to risks of commodity price movements. Generation buys and sells energy and other products and enters into financial contracts to manage risk and hedge various positions in Generation’s power generation portfolio. Generation is exposed to volatility in financial results for unhedged positions as well as the risk of ineffective hedges. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations could be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions could have on its consolidated financial statements.

Financial performance and load requirements could be negatively affected if Generation is unable to effectively manage its power portfolio (Exelon and Generation).

A significant portion of Generation’s power portfolio is used to provide power under procurement contracts with the Utility Registrants and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation’s output is sold in the wholesale power markets. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation’s financial results could be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio or effectively address the changes in the wholesale power markets.

The impacts of significant economic downturns or increases in customer rates, could lead to decreased volumes delivered and increased expense for uncollectible customer balances (All Registrants).

The impacts of significant economic downturns on the Utility Registrants' customers, such as less demand for products and services provided by commercial and industrial customers, and the related regulatory limitations on residential service terminations, could result in an increase in the number of uncollectible customer balances. Further, increases in customer rates, including those related to increases in purchased power and natural gas prices, could result in declines in customer usage and lower revenues for the Utility Registrants that do not have decoupling mechanisms.

Generation's customer-facing energy delivery activities face similar economic downturn risks, such as lower volumes sold and increased expense for uncollectible customer balances.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information of the Registrants’ credit risk.

The Registrants' results could be negatively affected by the impacts of COVID-19 (All Registrants).

COVID-19 is an 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 their 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. See Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Executive Overview for additional information.

The Registrants could be negatively affected by the impacts of weather (All Registrants).

Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting revenues at PECO, DPL Delaware, and ACE. Due to revenue decoupling, BGE, Pepco, and DPL Maryland recognize revenues at MDPSC and DCPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period and are not affected by actual weather with the exception of major storms. ComEd’s customer rates are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution revenue.

Extreme weather conditions or damage resulting from storms could stress the Utility Registrants' transmission and distribution systems, communication systems, and technology, resulting in increased maintenance and capital costs and limiting each company's ability to meet peak customer demand. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and could make period comparisons less relevant.

Generation’s operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation could require greater resources to meet its contractual commitments. Extreme weather conditions or storms could affect the availability of generation and its transmission, limiting Generation’s ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage could impact Generation’s ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could cause Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Climate change projections suggest increases to summer temperature and humidity trends, as well as more erratic precipitation and storm patterns over the long-term in the areas where Registrants have generation, transmission, and distribution assets. The frequency in which weather conditions emerge outside the current expected climate norms could contribute to weather-related impacts discussed above.

Long-lived assets, goodwill, and other assets could become impaired (All Registrants).

Long-lived assets represent the single largest asset class on the Registrants’ statements of financial position. In addition, Exelon, ComEd, and PHI have material goodwill balances.

The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as, but not limited to, the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered.

ComEd and PHI perform an assessment for possible impairment of their goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting units below their carrying amount. Regulatory actions or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd’s, Pepco’s, DPL’s, and ACE’s business, and the fair value of debt, could potentially result in future impairments of Exelon’s, ComEd's, and PHI’s goodwill.

An impairment would require the Registrants to reduce the carrying value of the long-lived asset or goodwill to fair value through a non-cash charge to expense by the amount of the impairment. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates, Note 8 — Property, Plant, and Equipment, Note 12 — Asset Impairments and Note 13 — Intangible Assets of the Combined Notes to the Consolidated Financial Statements for additional information on long-lived asset impairments and goodwill impairments.

The Registrants could incur substantial costs in the event of non-performance by third-parties under indemnification agreements, or when the Registrants have guaranteed their performance. Generation is exposed to other credit risks in the power markets that are beyond its control (All Registrants).

The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations. Each of the Utility Registrants has transferred its former generation business to a third party and in each case the transferee has agreed to assume certain obligations and to indemnify the applicable Utility Registrant for such obligations. In connection with the restructurings under which ComEd, PECO, and BGE transferred their generating assets to Generation, Generation assumed certain of ComEd’s, PECO’s, and BGE's rights and obligations with respect to their former generation businesses. Further, ComEd, PECO, and BGE have entered into agreements with third parties under which the third-party agreed to indemnify ComEd, PECO, or BGE for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party, Generation, or the transferee of Pepco's, DPL's, or ACE’s generation facilities experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, the applicable Utility Registrant could be liable for any existing or future claims. In addition, the Utility Registrants have residual liability under certain laws in connection with their former generation facilities.

The Registrants have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of assets and they could incur substantial costs to fulfill their obligations under these indemnities.

The Registrants have issued guarantees of the performance of third parties, which obligate the Registrants to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees.

In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money or are obligated to purchase energy or fuel from Generation, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, Generation could be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent amounts, if any, were already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation's retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that could be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Regulatory, Legislative, and Legal Factors

Federal or state legislative or regulatory actions could negatively affect the scope and functioning of the wholesale markets (Exelon and Generation).

Approximately 70% of Generation's generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation's future results of operations are impacted by (1) FERC's and PJMs support for policies that favor the preservation of competitive wholesale power markets and recognize the value of zero-carbon electricity and resiliency and for states' energy objectives and policies (2) the absence of material changes to market structures that would limit or otherwise negatively affect Exelon or Generation. Generation could also be affected by state laws, regulations, or initiatives to subsidize existing or new generation.

FERC's requirements for market-based rate authority could pose a risk that Generation may no longer satisfy FERC's tests for market-based rates.

The Registrants' are highly regulated and could be negatively affected by regulatory and legislative actions (All Registrants).

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation.

Generation's consolidated financial statements are significantly affected by its sales and purchases of commodities at market-based rates, as opposed to cost-based or other similarly regulated rates and Federal and state regulatory and legislative developments related to emissions, climate change, capacity market mitigation, energy price information, resilience, fuel diversity, and RPS. Legislative and regulatory efforts in Illinois, New York, and New Jersey to preserve the environmental attributes and reliability benefits of zero-emission nuclear-powered generating facilities through ZEC programs are or could be subject to legal and regulatory challenges and, if overturned, could result in the early retirement of certain of Generation's nuclear plants. See Note 3 — Regulatory Matters and Note 7 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

The Utility Registrants' consolidated financial statements are heavily dependent on the ability of the Utility Registrants to recover their costs for the retail purchase and distribution of power and natural gas to their customers.

Fundamental changes in regulations or other adverse legislative actions affecting the Registrants' businesses would require changes in their business planning models and operations. The Registrants cannot predict when or whether legislative and regulatory proposals could become law or what their effect will be on the Registrants.

Changes in the Utility Registrants' respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy, and subject to appeal, which lead to uncertainty as to the ultimate result and which could introduce time delays in effectuating rate changes (Exelon and the Utility Registrants).

The Utility Registrants are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups, and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for a Utility Registrant to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, subject to refund or disallowed, including recovery mechanisms for costs associated with the procurement of electricity or gas, credit losses, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs. In certain instances, the Utility Registrants could agree to negotiated settlements related to various rate matters, customer initiatives, or franchise agreements. These settlements are subject to regulatory approval. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of the Utility Registrants to recover their costs or earn an adequate return. See Note 3 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information.

NRC actions could negatively affect the operations and profitability of Generation's nuclear generating fleet (Exelon and Generation).

Regulatory risk. A change in the Atomic Energy Act or the applicable regulations or licenses could require a substantial increase in capital expenditures or could result in increased operating or decommissioning costs. Events at nuclear plants owned by others, as well as those owned by Generation, could cause the NRC to initiate such actions.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF and the timing of such a facility opening, will significantly affect the costs associated with storage of SNF and the ultimate amounts received from the DOE to reimburse Generation for these costs.

Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect Generation's ability to fully decommission its nuclear units. Generation cannot predict what, if any, fee may be established in the future for SNF disposal. See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the SNF obligation.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of the Utility Registrants to the results of PJM's RTEP and NERC compliance requirements (All Registrants).

The Registrants as users, owners, and operators of the bulk power transmission system, including Generation and the Utility Registrants, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. PECO, BGE, and DPL, as operators of natural gas distribution systems, are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC, MDPSC, DCPSC, DPSC, and NJBPU impose certain distribution reliability standards on the Utility Registrants. If the Registrants were found not to be in compliance with the Federal and state mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

The Registrants could incur substantial costs to fulfill their obligations related to environmental and other matters (All Registrants).

The businesses that the Registrants operate are subject to extensive environmental regulation and legislation by local, state, and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions, hazardous and solid waste, and activities affecting surface waters, groundwater, and aquatic and other species. Violations of these requirements could subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages, or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generated or released. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and could be subject to additional proceedings in the future. See ITEM 1. BUSINESS — Environmental Regulation for additional information.

The Registrants could be negatively affected by challenges to tax positions taken, tax law changes, and the inherent difficulty in quantifying potential tax effects of business decisions. (All Registrants).

The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use, and employment-related taxes and ongoing appeal issues related to these tax matters. These judgments include reserves established for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. See Note 1 — Significant Accounting Policies and Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants could be negatively affected by federal and state RPS and/or energy conservation legislation, along with energy conservation by customers (All Registrants).

Changes to current state legislation or the development of Federal legislation that requires the use of clean, renewable, and alternate fuel sources could significantly impact Generation and the Utility Registrants, especially if timely cost recovery is not allowed for Utility Registrants. The impact could include increased costs and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, could increase capital expenditures and could significantly impact the Utility Registrants consolidated financial statements if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of the Registrants. See ITEM 1. BUSINESS — Environmental Regulation — Renewable and Clean Energy Standards for additional information.

Generation's affiliation with the Utility Registrants, together with the presence of a substantial percentage of Generation's physical asset base within the Utility Registrants' service territories, could increase Generation's cost of doing business to the extent future complaints or challenges regarding the Utility Registrants' retail rates result in settlements or legislative or regulatory requirements funded in part by Generation (Exelon and Generation).

Generation has significant generating resources within the service areas of the Utility Registrants and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators, and advocacy groups are aware of Generation's affiliation with the Utility Registrants and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups could question or challenge costs and transactions incurred by the Utility Registrants with Generation, irrespective of any previous regulatory processes or approvals underlying those transactions. These challenges could increase the time, complexity, and cost of the associated regulatory proceedings, and the occurrence of such challenges could subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators could seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes.

The Registrants could be subject to adverse publicity and reputational risks, which make them vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences (All Registrants).

The Registrants could be the subject of public criticism. Adverse publicity of this nature could render public service commissions and other regulatory and legislative authorities less likely to view energy companies such as Exelon and its subsidiaries in a favorable light, and could cause Exelon and its subsidiaries to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent legislative or regulatory requirements (e.g. disallowances of costs, lower ROEs).

Legal proceedings could result in a negative outcome, which the Registrants cannot predict (All Registrants).

The Registrants are involved in legal proceedings, claims, and litigation arising out of their business operations. The material ones are summarized in Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures, result in lost revenue, or restrict existing business activities.

Exelon and ComEd have received requests for information related to an SEC investigation into their lobbying activities. The outcome of the investigations could have a material adverse effect on their reputation and consolidated financial statements (Exelon and ComEd).

On October 22, 2019, the SEC notified Exelon and ComEd that it had opened an investigation into their lobbying activities in the state of Illinois. Exelon and ComEd have cooperated fully, including by providing all information requested by the SEC, and intend to continue to cooperate fully and expeditiously with the SEC. The outcome of the SEC's investigation cannot be predicted and could subject Exelon and ComEd to civil penalties, sanctions, or other remedial measures. Any of the foregoing, as well as the appearance of non-compliance with anti-corruption and anti-bribery laws, could have an adverse impact on Exelon's and ComEd's reputations or relationships with regulatory and legislative authorities, customers, and other stakeholders, as well as their consolidated financial statements. See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

If ComEd violates its Deferred Prosecution Agreement announced on July 17, 2020, it could have an adverse effect on the reputation and consolidated financial statements of Exelon and ComEd (Exelon and ComEd).

On July 17, 2020, ComEd entered into a Deferred Prosecution Agreement (DPA) with the U.S. Attorney's Office for the Northern District of Illinois (USAO) to resolve the USAO's investigation into Exelon's and ComEd's lobbying activities in the State of Illinois. Exelon was not made a party to the DPA and the investigation by the USAO into Exelon's activities ended with no charges being brought against Exelon. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the Speaker of the Illinois House of Representatives and the Speaker's associates, with the intent to influence the Speaker's action regarding legislation affecting ComEd's interests. The DPA provides that the USAO will defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period subject to certain obligations of ComEd, including, but not limited to, the following: (i) payment to the United States Treasury of $200 million; (ii) continued full cooperation with the government's investigation; and (iii) ComEd's adoption and maintenance of remedial measures involving compliance and reporting undertakings as specified in the DPA. If ComEd is found to have breached the terms of the DPA, the USAO may elect to prosecute, or bring a civil action against, ComEd for conduct alleged in the DPA or known to the government, which could result in fines or penalties and could have an adverse impact on Exelon's and ComEd's reputation or relationships with regulatory and legislative authorities, customers and other stakeholders, as well as their consolidated financial statements. See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

Generation's financial performance could be negatively affected by risks arising from its ownership and operation of hydroelectric facilities (Exelon and Generation).

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not issue new operating licenses for Generation's hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation could also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions could be imposed as part of the license renewal process that could adversely affect operations, could require a substantial increase in capital expenditures, could result in increased operating costs or could render the project uneconomic. Similar effects could result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

Operational Factors

The Registrants are subject to risks associated with climate change (All Registrants).

The Registrants periodically perform analyses to better understand how climate change could affect their facilities and operations. The Registrants primarily operate in the Midwest and East Coast of the United States, areas that historically have been prone to various types of severe weather events, such that the Registrants have well-developed response and recovery programs based on these historical events. However, the Registrants' physical facilities could be placed at greater risk of damage should changes in the global climate impact temperature and weather patterns, resulting in more intense, frequent and extreme weather events, unprecedented levels of precipitation, sea level rise, increased surface water temperatures, and/or other effects. In addition, changes to the climate may impact levels and patterns of demand for energy and related services, which could affect Registrants' operations. Over time, the Registrants may need to make additional investments to protect facilities from physical climate-related risks and/or adapt to changes in operational requirements as a result of climate change.

The Registrants also periodically perform analyses of potential pathways to reduce power sector and economy-wide GHG emissions to mitigate climate change. To the extent additional GHG reduction regulation or legislation becomes effective at the Federal and/or state levels, the Registrants could incur costs to further limit the GHG emissions from their operations or otherwise comply with applicable requirements. To the extent such additional regulation or legislation does not become effective, the potential competitive advantage offered by Registrant's low-carbon emission profile may be reduced. See ITEM 1. BUSINESS — Climate Change Mitigation.

Generation's financial performance could be negatively affected by matters arising from its ownership and operation of nuclear facilities (Exelon and Generation).

Nuclear capacity factors. Capacity factors for nuclear generating units, significantly affect Generation's results of operations. Lower capacity factors could decrease Generation's revenues and increase operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation's obligations to committed third-party sales, including the Utility Registrants. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, could have a significant impact on Generation's results of operations. When refueling outages last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease, and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales and higher operating and maintenance costs.

Nuclear fuel quality. The quality of nuclear fuel utilized by Generation could affect the efficiency and costs of Generation's operations. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs, and/or increased costs due to decreased generation capabilities.

Operational risk. Operations at any of Generation's nuclear generation plants could degrade to the point where Generation must shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes could require significant time and expense. Generation could choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation could lose revenue and incur increased fuel and purchased power expense to meet supply commitments.

For plants operated but not wholly owned by Generation, Generation could also incur liability to the co-owners. For nuclear plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants' output, Generation's results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy. In addition, closure of generating plants owned by others, or extended interruptions of generating plants, or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk and insurance. The consequences of a major incident could be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, could exceed Generation's resources, including insurance coverage. Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation's nuclear operations. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by Generation. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, whether owned by Generation or others, could result in increased regulation and reduced public support for nuclear-fueled energy.

As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance, $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.8 billion limit for a single incident.

See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information of nuclear insurance.

Decommissioning obligation and funding. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility.

Generation recognizes as a liability the present value of the estimated future costs to decommission its nuclear facilities. The estimated liability is based on assumptions in the approach and timing of decommissioning the nuclear facilities, estimation of decommissioning costs, and Federal and state regulatory requirements. The costs of such decommissioning may substantially exceed such liability, as facts, circumstances or our estimates may change, including changes in the approach and timing of decommissioning activities, changes in decommissioning costs, changes in Federal or state regulatory requirements on the decommissioning of such facilities, other changes in our estimates or Generation's ability to effectively execute on its planned decommissioning activities.

Generation makes contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation, through PECO, has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from utility customers for any of its other nuclear units if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units could be negatively affected.

Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income, and the adverse impact to Exelon's and Generation's financial statements could be material. Any changes to the existing PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's financial statements could be material.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. If the investments held by Generation's NDT funds are not sufficient to fund the decommissioning of Generation's nuclear units, Generation could be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met.

See Note 10 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

The Utility Registrants' operating costs are affected by their ability to maintain the availability and reliability of their delivery and operational systems (Exelon and the Utility Registrants).

Failures of the equipment or facilities used in the Utility Registrants' delivery systems could interrupt the electric transmission and electric and natural gas delivery, which could result in a loss of revenues and an increase in maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including natural causes such as weather or information systems failure. Specifically, if the implementation of AMI, smart grid, or other technologies in the Utility Registrants' service territory fail to perform as intended or are not successfully integrated with billing and other information systems, or if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, the Utility Registrants' financial results could be negatively impacted. In addition, dependence upon automated systems could further increase the risk that operational system flaws or internal and/or external tampering or manipulation of those systems will result in losses that are difficult to detect.

Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd could be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, which could be material.

The Registrants are subject to physical security and cybersecurity risks (All Registrants).

The Registrants face physical security and cybersecurity risks. Threat sources continue to seek to exploit potential vulnerabilities in the electric and natural gas utility industry associated with protection of sensitive and confidential information, grid infrastructure, and other energy infrastructures, and such attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increases the potentially unfavorable impacts of such attacks. A security breach of the physical assets or information systems of the Registrants, their competitors, vendors, business partners and interconnected entities in RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or result in the theft or inappropriate release of certain types of information, including critical infrastructure information, sensitive customer, vendor, and employee data, trading or other confidential data. The risk of these system-related events and security breaches occurring continues to intensify, and while the Registrants have been, and will likely continue to be, subjected to physical and cyber-attacks, to date none has directly experienced a material breach or disruption to its network or information systems or our service operations. However, as such attacks continue to increase in sophistication and frequency, the Registrants may be unable to prevent all such attacks in the future. If a significant breach were to occur, the reputation of the Registrants could be negatively affected, customer confidence in the Registrants or others in the industry could be diminished, or the Registrants could be subject to legal claims, loss of revenues, increased costs, or operations shutdown. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result.

The Utility Registrants' deployment of smart meters throughout their service territories could increase the risk of damage from an intentional disruption of the system by third parties.

In addition, new or updated security regulations or unforeseen threat sources could require changes in current measures taken by the Registrants or their business operations and could adversely affect their consolidated financial statements.

The Registrants’ employees, contractors, customers, and the general public could be exposed to a risk of injury due to the nature of the energy industry (All Registrants).

Employees and contractors throughout the organization work in, and customers and the general public could be exposed to, potentially dangerous environments near the Registrants’ operations. As a result, employees, contractors, customers, and the general public are at some risk for serious injury, including loss of life. These risks include nuclear accidents, dam failure, gas explosions, pole strikes, and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic, and other significant events could negatively impact the Registrants' results of operations, their ability to raise capital and their future growth (All Registrants).

Generation’s fleet of power plants and the Utility Registrants' distribution and transmission infrastructures could be affected by natural disasters and extreme weather events, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants’ service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Natural disasters and other significant events increase the risk to Generation that the NRC or other regulatory or legislative bodies could change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security, and environmental and radiological matters. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation’s continued operation, particularly the cooling of generating units.

The impact that potential terrorist attacks could have on the industry and on Exelon is uncertain. The Registrants face a risk that their operations would be direct targets or indirect casualties of an act of terror. Any retaliatory military strikes or sustained military campaign could affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cybersecurity of Exelon’s facilities, which could adversely affect Exelon’s ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession, or other factors also could result in a decline in energy consumption or interruption of fuel or the supply chain. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants could be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate Exelon's generating and transmission and distribution assets could be affected.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property, casualty and cybersecurity losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

The Registrants’ businesses are capital intensive, and their assets could require significant expenditures to maintain and are subject to operational failure, which could result in potential liability (All Registrants).

The Registrants’ businesses are capital intensive and require significant investments by Generation in electric generating facilities and by the Utility Registrants in transmission and distribution infrastructure projects. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants’ control, and could require significant expenditures to operate efficiently. The Registrants consolidated financial statements could be negatively affected if they were unable to effectively manage their capital projects or raise the necessary capital. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources for additional information regarding the Registrants’ potential future capital expenditures.

The Utility Registrants' respective ability to deliver electricity, their operating costs, and their capital expenditures could be negatively impacted by transmission congestion and failures of neighboring transmission systems (Exelon and the Utility Registrants).

Demand for electricity within the Utility Registrants' service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage. Also, insufficient availability of electric supply to meet customer demand could jeopardize the Utility Registrants' ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring the Utility Registrants to upgrade or expand their respective transmission systems through additional capital expenditures.

PJMs systems and operations are designed to ensure the reliable operation of the transmission grid and prevent the operations of one utility from having an adverse impact on the operations of the other utilities. However, service interruptions at other utilities may cause interruptions in the Utility Registrants' service areas.

The Registrants consolidated financial statements could be negatively affected if they fail to attract and retain an appropriately qualified workforce (All Registrants).

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs, and safety costs, could arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission, and distribution operations.

The Registrants could make acquisitions or investments in new business initiatives and new markets, which may not be successful or achieve the intended financial results (All Registrants).

Generation could continue to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. This could include investment opportunities in renewables, development of natural gas generation, nuclear advisory or operating services for third parties, distributed generation, potential expansion of the existing wholesale gas businesses, and entry into LNG. Such initiatives could involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered during diligence performed prior to launching an initiative or entering a market. Additionally, it is possible that FERC, state public utility commissions or others could impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment.

The Utility Registrants face risks associated with their regulatory-mandated initiatives, such as smart grids and utility of the future. These risks include, but are not limited to, cost recovery, regulatory concerns, cybersecurity, and obsolescence of technology. Such initiatives may not be successful.

The Registrants may not realize or achieve the anticipated cost savings through the cost management efforts (All Registrants).

The Registrants' future financial performance and level of profitability is dependent, in part, on various cost reduction initiatives. The Registrants may encounter challenges in executing these cost reduction initiatives and not achieve the intended cost savings.

Risks Related to the Planned Separation (Exelon and Generation)

The planned separation is contingent upon regulatory approvals and satisfaction of other conditions and may not be completed in accordance with the expected plans or anticipated timeline, or at all, which could negatively affect Exelon's and Generation's consolidated financial statements.

Exelon is targeting to complete the separation in the first quarter of 2022, subject to final approval by Exelon's Board of Directors, a Form 10 registration statement being declared effective by the SEC, regulatory approvals, and satisfaction of other conditions. The planned separation is subject to approval by the FERC, NRC and NYPSC. There can be no assurance that any separation transaction will ultimately occur or, if one does occur, of its terms or timing. If the planned separation is not completed or is delayed, Exelon's and Generation's consolidated financial statements may be materially adversely affected, and the market price of Exelon's common stock may be affected.

The plan to separate into two publicly traded companies will involve significant time and expense, which could disrupt or adversely affect our business.

The planned separation is complex in nature, and unanticipated developments or changes, including challenges in executing the separation, could delay or prevent the completion of the proposed separation, or cause the separation to occur on terms or conditions that are different or less favorable than expected. Additionally, Exelon's Board of Directors, in its sole and absolute discretion, may decide not to proceed with the separation at any time prior to the distribution date. The process of completing the proposed separation has been and is expected to continue to be time-consuming and involves significant costs and expenses.

The planned separation may not achieve some or all of the anticipated benefits and each separate company following the separation may underperform relative to Exelon's expectations.

By separating the Utility Registrants and Generation, Exelon is creating two publicly traded companies with the resources necessary to best serve customers and sustain long-term investment and operating excellence. The separate companies are expected to create value by having the strategic flexibility to focus on their unique customer, market and community priorities. However, the planned separation may not provide such results on the scope or scale that Exelon anticipates, and Exelon and Generation may not realize the anticipated benefits of the planned separation. Failure to do so could have a material adverse effect on the financial statements of each separate company and their respective common stock price.

Following the planned separation, the companies anticipate to maintain investment grade credit ratings. Ratings are based upon assessments of multiple factors, including a company's credit metrics as well as industry and macroeconomic changes and trends. If a rating agency were to downgrade the rating below investment grade, the separate companies' borrowing costs would increase and their funding sources could decrease, which could have a material adverse effect on the financial statements of the affected company.

The common stock of the separately publicly traded companies following the separation may collectively trade at a value less than the price at which Exelon's common stock might have traded had the separation not occurred.

There could be significant liability if the planned spin-off is determined to be a taxable transaction.

Under the separation plan, Exelon shareholders will retain their current shares of Exelon stock and receive a pro-rata distribution of shares of the new company's stock in a transaction that is expected to be tax-free to Exelon and its shareholders under Sections 355 and 368 of the IRC. Exelon will seek a private letter ruling from the IRS regarding the tax-free nature of the transaction. Exelon will also seek from its tax advisors an opinion with respect to certain U.S. federal income tax consequences of the spin-off. If the planned spin-off ultimately is determined to be taxable, the spin-off could be treated as a taxable dividend to Exelon's shareholders for U.S. federal income tax purposes, and Exelon's shareholders could incur significant U.S. federal income tax liabilities. In addition, Exelon would recognize a taxable gain to the extent that the fair market value of the new company's stock exceeds its tax basis in such stock on the date of the planned separation. Exelon will enter into a Tax Matters Agreement with the new company to address how post-separation issues will be managed between the companies, as well as which company is responsible for taxes imposed as a result of the planned separation, if any.

See Note 26 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information on the planned separation.

ITEM 1B. UNRESOLVED STAFF COMMENTS

All Registrants

None.

ITEM 2. PROPERTIES

Generation

The following table presents Generation’s interests in net electric generating capacity by station at December 31, 2020:

Station(a)	Location	No. of Units	Percent Owned(b)	Primary Fuel Type	Primary Dispatch Type(c)	Net Generation Capacity (MW)(d)
Midwest						
Braidwood	Braidwood, IL	2		Uranium	Base-load	2,386
Byron	Byron, IL	2		Uranium	Base-load	2,347 (e)
LaSalle	Seneca, IL	2		Uranium	Base-load	2,320
Dresden	Morris, IL	2		Uranium	Base-load	1,845 (e)
Quad Cities	Cordova, IL	2	75	Uranium	Base-load	1,403 (f)
Clinton	Clinton, IL	1		Uranium	Base-load	1,080
Michigan Wind 2	Sanilac Co., MI	50	51 (g)	Wind	Intermittent	46 (f)
Beebe	Gratiot Co., MI	34	51 (g)	Wind	Intermittent	42 (f)
Michigan Wind 1	Huron Co., MI	46	51 (g)	Wind	Intermittent	35 (f)
Harvest 2	Huron Co., MI	33	51 (g)	Wind	Intermittent	30 (f)
Harvest	Huron Co., MI	32	51 (g)	Wind	Intermittent	27 (f)
Beebe 1B	Gratiot Co., MI	21	51 (g)	Wind	Intermittent	26 (f)
City Solar	Chicago, IL	1		Solar	Intermittent	9
Solar Ohio	Toledo, OH	2		Solar	Intermittent	4 (h)
Blue Breezes	Faribault Co., MN	2		Wind	Intermittent	3
CP Windfarm	Faribault Co., MN	2	51 (g)	Wind	Intermittent	2 (f)
Southeast Chicago	Chicago, IL	8		Gas	Peaking	296 (i)
Clinton Battery Storage	Blanchester, OH	1		Energy Storage	Peaking	10
Total Midwest						11,911
Mid-Atlantic						
Limerick	Sanatoga, PA	2		Uranium	Base-load	2,317
Peach Bottom	Delta, PA	2	50	Uranium	Base-load	1,324 (f)
Salem	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	995 (f)
Calvert Cliffs	Lusby, MD	2	50.01 (j)	Uranium	Base-load	895 (f)
Conowingo	Darlington, MD	11		Hydroelectric	Base-load	572
Criterion	Oakland, MD	28	51 (g)	Wind	Intermittent	36 (f)
Fair Wind	Garrett County, MD	12		Wind	Intermittent	30
Solar MC	Various, MD	44		Solar	Intermittent	44 (h)
Fourmile Ridge	Garrett County, MD	16	51 (g)	Wind	Intermittent	20 (f)
Solar New Jersey 1	Various, NJ	5		Solar	Intermittent	18 (h)
Solar New Jersey 2	Various, NJ	2		Solar	Intermittent	11 (h)
Solar Horizons	Emmitsburg, MD	1	51 (g)	Solar	Intermittent	16 (f)
Solar Maryland	Various, MD	11		Solar	Intermittent	8 (h)
Solar Maryland 2	Various, MD	3		Solar	Intermittent	8 (h)

Station[a]	Location	No. of Units	Percent Owned[b]	Primary Fuel Type	Primary Dispatch Type[c]	Net Generation Capacity (MW)[d]
JBAB Solar	District of Columbia	4		Solar	Intermittent	7 (h)
Gateway Solar	Berlin, MD	1		Solar	Intermittent	7 (h)
Constellation New Energy	Gaithersburg, MD	2		Solar	Intermittent	6 (h)
Solar Federal	Trenton, NJ	1		Solar	Intermittent	5 (h)
Solar New Jersey 3	Middle Township, NJ	5	51 (g)	Solar	Intermittent	2 (f)
Solar DC	District of Columbia	1		Solar	Intermittent	1 (h)
Muddy Run	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Eddystone, PA	2		Oil/Gas	Peaking	760
Perryman	Aberdeen, MD	5		Oil/Gas	Peaking	404
Croydon	West Bristol, PA	8		Oil	Peaking	391
Handsome Lake	Kennerdell, PA	5		Gas	Peaking	268
Richmond	Philadelphia, PA	2		Oil	Peaking	98
Philadelphia Road	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Eddystone, PA	4		Oil	Peaking	60
Delaware	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Philadelphia, PA	4		Oil	Peaking	52
Falls	Morrisville, PA	3		Oil	Peaking	51
Moser	Lower Pottsgrove Twp., PA	3		Oil	Peaking	51
Chester	Chester, PA	3		Oil	Peaking	39
Schuylkill	Philadelphia, PA	2		Oil	Peaking	30
Salem	Lower Alloways Creek Township, NJ	1	42.59	Oil	Peaking	16 (f)
Total Mid-Atlantic						9,729
ERCOT						
Whitetail	Webb County, TX	57	51 (g)	Wind	Intermittent	47 (f)
Sendero	Jim Hogg and Zapata County, TX	39	51 (g)	Wind	Intermittent	40 (f)
Constellation Solar Texas	Various, TX	11		Solar	Intermittent	13 (h)
Colorado Bend II	Wharton, TX	3		Gas	Intermediate	1,143
Wolf Hollow II	Granbury, TX	3		Gas	Intermediate	1,115
Handley 3	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	Fort Worth, TX	2		Gas	Peaking	870
Total ERCOT						3,623

Station(a)	Location	No. of Units	Percent Owned(b)	Primary Fuel Type	Primary Dispatch Type(c)	Net Generation Capacity (MW)(d)
New York						
Nine Mile Point	Scriba, NY	2	50.01 (j)	Uranium	Base-load	838 (f)
FitzPatrick	Scriba, NY	1		Uranium	Base-load	842
Ginna	Ontario, NY	1	50.01 (j)	Uranium	Base-load	288 (f)
Solar New York	Bethlehem, NY	1		Solar	Intermittent	3 (h)
Total New York						1,971
Other						
Antelope Valley	Lancaster, CA	1		Solar	Intermittent	242
Bluestem	Beaver County, OK	60	51 (g)(k)	Wind	Intermittent	101 (f)
Shooting Star	Kiowa County, KS	65	51 (g)	Wind	Intermittent	53 (f)
Albany Green Energy	Albany, GA	1	99 (l)	Biomass	Base-load	50 (f)
Solar Arizona	Various, AZ	127		Solar	Intermittent	46 (h)
Bluegrass Ridge	King City, MO	27	51 (g)	Wind	Intermittent	29 (f)
California PV Energy 2	Various, CA	89		Solar	Intermittent	27 (h)
Conception	Barnard, MO	24	51 (g)	Wind	Intermittent	26 (f)
Cow Branch	Rock Port, MO	24	51 (g)	Wind	Intermittent	26 (f)
Solar Arizona 2	Various, AZ	56		Solar	Intermittent	34 (h)
California PV Energy	Various, CA	53		Solar	Intermittent	21 (h)
Mountain Home	Glenns Ferry, ID	20	51 (g)	Wind	Intermittent	21 (f)
High Mesa	Elmore Co., ID	19	51 (g)	Wind	Intermittent	20 (f)
Echo 1	Echo, OR	21	50.49 (g)	Wind	Intermittent	17 (f)
Sacramento PV Energy	Sacramento, CA	4	51 (g)	Solar	Intermittent	30 (f)
Cassia	Buhl, ID	14	51 (g)	Wind	Intermittent	15 (f)
Wildcat	Lovington, NM	13	51 (g)	Wind	Intermittent	14 (f)
Echo 2	Echo, OR	10	51 (g)	Wind	Intermittent	10 (f)
Solar Georgia 2	Various, GA	8		Solar	Intermittent	10 (h)
Tuana Springs	Hagerman, ID	8	51 (g)	Wind	Intermittent	9 (f)
Solar Georgia	Various, GA	10		Solar	Intermittent	8 (h)
Greensburg	Greensburg, KS	10	51 (g)	Wind	Intermittent	6 (f)
Solar Massachusetts	Various, MA	10		Solar	Intermittent	7 (h)
Outback Solar	Christmas Valley, OR	1		Solar	Intermittent	6 (h)
Echo 3	Echo, OR	6	50.49 (g)	Wind	Intermittent	5 (f)
Holyoke Solar	Various, MA	2		Solar	Intermittent	5 (h)
Three Mile Canyon	Boardman, OR	6	51 (g)	Wind	Intermittent	5 (f)
Loess Hills	Rock Port, MO	4		Wind	Intermittent	5
California PV Energy 3	Various, CA	31		Solar	Intermittent	8 (h)
Denver Airport Solar	Denver, CO	1	51 (g)	Solar	Intermittent	4 (f)
Solar Net Metering	Uxbridge, MA	1		Solar	Intermittent	2 (h)
Solar Connecticut	Various, CT	1		Solar	Intermittent	1 (h)
Mystic 8, 9	Charlestown, MA	6		Gas	Intermediate	1,413 (e)

Station[a]	Location	No. of Units	Percent Owned[b]	Primary Fuel Type	Primary Dispatch Type[c]	Net Generation Capacity (MW)[d]
Hillabee	Alexander City, AL	3		Gas	Intermediate	753
Mystic 7	Charlestown, MA	1		Oil/Gas	Intermediate	512 (m)
Wyman 4	Yarmouth, ME	1	5.9	Oil	Intermediate	35 (f)
Grand Prairie	Alberta, Canada	1		Gas	Peaking	105
West Medway	West Medway, MA	3		Oil	Peaking	124
West Medway II	West Medway, MA	2		Oil/Gas	Peaking	192
Framingham	Framingham, MA	3		Oil	Peaking	31
Mystic Jet	Charlestown, MA	1		Oil	Peaking	9 (m)
Total Other						4,037
Total						31,271

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, and Salem, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermittent units are plants with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations and wind and solar facilities reflect a summer rating.
(e) Generation has announced it will permanently cease generation operations at Byron and Dresden nuclear facilities in 2021 and Mystic Unit 8 and 9 in 2024. See Note 7 — Early Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Reflects the prior sale of 49% of EGRP to a third party. See Note 23 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information.
(h) On December 8, 2020, Generation entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of Generation's solar business. The transaction is expected to be completed in the first half of 2021. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information.
(i) Generation has deactivated the site and is evaluating for potential return of service or retirement beyond 2021.
(j) Reflects Generation’s interest in CENG, a joint venture with EDF. See ITEM 1. — BUSINESS — Exelon Generation Company, LLC — Nuclear Facilities for additional information.
(k) EGRP owns 100% of the Class A membership interests and a tax equity investor owns 100% of the Class B membership interests of the entity that owns the Bluestem generating assets.
(l) Generation directly owns a 50% interest in the Albany Green Energy station and an additional 49% through the consolidation of a Variable Interest Entity.
(m) Generation has plans to retire and cease plant operations in 2021.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies, or generating units being temporarily out of service for inspection, maintenance, refueling, repairs, or modifications required by regulatory authorities.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. BUSINESS — Exelon Generation Company, LLC. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect in Generation’s consolidated financial condition or results of operations.

The Utility Registrants

The Utility Registrants' electric substations and a portion of their transmission rights are located on property that they own. A significant portion of their electric transmission and distribution facilities are located above or underneath highways, streets, other public places, or property that others own. The Utility Registrants believe that they have satisfactory rights to use those places or property in the form of permits, grants, easements, licenses, and franchise rights; however, they have not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

The Utility Registrants’ high voltage electric transmission lines owned and in service at December 31, 2020 were as follows:

Voltage	Circuit Miles					
(Volts)	ComEd	PECO	BGE	Pepco	DPL	ACE
765,000	90	—	—	—	—	—
500,000(a)	—	188 (a)	216	109	16 (a)	— (a)
345,000	2,676	—	—	—	—	—
230,000	—	549	358	770	472	274
138,000	2,245	135	55	61	586	214
115,000	—	—	712	25	—	—
69,000	—	177	—	—	567	667

(a) In addition, PECO, DPL, and ACE have an ownership interest located in Delaware and New Jersey. See Note 9 - Jointly Owned Electric Utility Plant - for additional information.

The Utility Registrants' electric distribution system includes the following number of circuit miles of overhead and underground lines:

Circuit Miles	ComEd	PECO	BGE	Pepco	DPL	ACE
Overhead	35,379	12,967	9,179	4,082	6,007	7,393
Underground	32,349	9,463	17,650	6,949	6,360	2,984

Gas

The following table presents PECO’s, BGE’s, and DPL’s natural gas pipeline miles at December 31, 2020:

	PECO	BGE	DPL
Transmission	9	152	8 (a)
Distribution	6,946	7,443	2,142
Service piping	6,449	6,383	1,461
Total	13,404	13,978	3,611

(a) DPL has a 10% undivided interest in approximately 8 miles of natural gas transmission mains located in Delaware which are used by DPL for its natural gas operations and by 90% owner for distribution of natural gas to its electric generating facilities.

The following table presents PECO's, BGE's, and DPL's natural gas facilities:

Registrant	Facility	Location	Storage Capacity (mmcf)	Send-out or Peaking Capacity (mmcf/day)
PECO	LNG Facility	West Conshohocken, PA	1,200	160
PECO	Propane Air Plant	Chester, PA	105	25
BGE	LNG Facility	Baltimore, MD	1,056	332
BGE	Propane Air Plant	Baltimore, MD	550	85
DPL	LNG Facility	Wilmington, DE	250	25

PECO, BGE, and DPL also own 30, 30, and 10 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout their gas service territory, respectively.

First Mortgage and Insurance

The principal properties of ComEd, PECO, PEPCO, DPL, and ACE are subject to the lien of their respective Mortgages under which their respective First Mortgage Bonds are issued. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

The Utility Registrants maintain property insurance against loss or damage to their properties by fire or other perils, subject to certain exceptions. For their insured losses, the Utility Registrants are self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect in the consolidated financial condition or results of operations of the Utility Registrants.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes, and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

All Registrants

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 Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

All Registrants

Not Applicable to the Registrants.

PART II

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

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon's common stock is listed on the Nasdaq (trading symbol: EXC). As of January 31, 2021, there were 976,337,799 shares of common stock outstanding and approximately 91,240 record holders of common stock.

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index, for the period 2016 through 2020.

This performance chart assumes:

- $100 invested on December 31, 2015 in Exelon common stock, the S&P 500 Stock Index, and the S&P Utility Index; and
- All dividends are reinvested.

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Value of Investment at December 31,						
	2015	2016	2017	2018	2019	2020
Exelon Corporation	$100	$132.81	$152.79	$180.80	$188.53	$181.20
S&P 500	$100	$111.96	$136.40	$130.42	$171.49	$203.04
S&P Utilities	$100	$116.29	$130.36	$135.72	$171.48	$172.31

Generation

As of January 31, 2021, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2021, there were 127,021,370 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2021, in addition to Exelon, there were 286 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2021, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2021, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

PHI

As of January 31, 2021, Exelon indirectly held the entire membership interest in PHI.

Pepco

As of January 31, 2021, there were 100 outstanding shares of common stock, $0.01 par value, of Pepco, all of which were indirectly held by Exelon.

DPL

As of January 31, 2021, there were 1,000 outstanding shares of common stock, $2.25 par value, of DPL, all of which were indirectly held by Exelon.

ACE

As of January 31, 2021, there were 8,546,017 outstanding shares of common stock, $3.00 par value, of ACE, all of which were indirectly held by Exelon.

All Registrants

Dividends

Under applicable Federal law, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, or ACE may limit the dividends that these companies can distribute to Exelon.

ComEd has agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to restrictions established by the MDPSC that prohibit BGE from paying a dividend on its common shares if (a) after the dividend payment, BGE’s equity ratio would be below 48% as calculated pursuant to the MDPSC’s ratemaking precedents or (b) BGE’s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. No such event has occurred.

Pepco is subject to certain dividend restrictions established by settlements approved in Maryland and the District of Columbia. Pepco is prohibited from paying a dividend on its common shares if (a) after the dividend payment, Pepco's equity ratio would be below 48% as equity levels are calculated under the ratemaking precedents of the MDPSC and DCPSC or (b) Pepco’s senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. No such event has occurred.

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 below 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.

ACE is subject to certain dividend restrictions established by settlements approved in New Jersey. ACE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, ACE's equity ratio would be below 48% as equity levels are calculated under the ratemaking precedents of the NJBPU or (b) ACE's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. ACE is also subject to a dividend restriction which requires ACE to obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%. No such events have occurred.

Exelon’s Board of Directors approved an updated dividend policy for 2021. The 2021 quarterly dividend will remain the same as the 2020 dividend of $0.3825 per share.

At December 31, 2020, Exelon had retained earnings of $16,735 million, including Generation’s undistributed earnings of $2,805 million, ComEd’s retained earnings of $1,456 million consisting of retained earnings appropriated for future dividends of $3,095 million, partially offset by $1,639 million of unappropriated accumulated deficits, PECO’s retained earnings of $1,519 million, BGE’s retained earnings of $1,879 million, and PHI's undistributed losses of $68 million.

The following table sets forth Exelon’s quarterly cash dividends per share paid during 2020 and 2019:

	2020				2019			
(per share)	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Exelon	$ 0.3825	$ 0.3825	$ 0.3825	$ 0.3825	$ 0.3625	$ 0.3625	$ 0.3625	$ 0.3625

The following table sets forth Generation's and PHI's quarterly distributions and ComEd's, PECO's, BGE's, Pepco's, DPL's, and ACE's quarterly common dividend payments:

	2020				2019			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 328	$ 469	$ 469	$ 468	$ 225	$ 225	$ 224	$ 225
ComEd	126	124	124	125	128	126	127	127
PECO	85	85	85	85	90	88	90	90
BGE	60	62	62	62	55	57	56	56
PHI	102	183	134	134	97	213	88	128
Pepco	58	73	73	28	40	101	48	24
DPL	42	33	14	52	34	35	29	41
ACE	3	76	12	23	24	76	12	12

First Quarter 2021 Dividend

On February 21, 2021, Exelon's Board of Directors declared a regular quarterly dividend of $0.3825 per share on Exelon's common stock for the first quarter of 2021. The dividend is payable on Monday, March 15, 2021, to shareholders of record of Exelon as of 5 p.m. Eastern time on Monday, March 8, 2021.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

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

Exelon has eleven reportable segments consisting of Generation's five reportable segments (Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions), ComEd, PECO, BGE, Pepco, DPL, and ACE. See Note 1 — Significant Accounting Policies and Note 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's principal subsidiaries and reportable segments.

Exelon's consolidated financial information includes the results of its eight separate operating subsidiary registrants, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations summarizes results for the year ended December 31, 2020 compared to the year ended December 31, 2019, and 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. For discussion of the year ended December 31, 2019 compared to the year ended December 31, 2018, refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS in the 2019 Form 10-K, which was filed with the SEC on February 11, 2020.

COVID-19. The Registrants have taken steps to mitigate the potential risks posed by the global outbreak (pandemic) of COVID-19. The Registrants provide a critical service to our customers which means that it is paramount that we keep our employees who operate our businesses 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. The Registrants have implemented work from home policies where appropriate, and imposed travel limitations on their employees. In addition, the Registrants have updated existing business continuity plans 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 in 2020 as a 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 9A. CONTROLS AND PROCEDURES for additional information.

Unfavorable economic conditions due to COVID-19 have impacted the demand for electricity and natural gas at Generation and the Utility Registrants, which has resulted in a decrease in operating revenues.

As a result of COVID-19, Generation temporarily suspended interruption of service for all retail residential customers for non-payment and temporarily ceased new late payment fees for all retail customers from March to May of 2020. Starting in March of 2020, the Utility Registrants also temporarily suspended customer disconnections for non-payment and temporarily ceased new late payment fees for all customers and restored service to customers upon request who were disconnected in the last twelve months. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on such measures at the Utility Registrants. At Generation, such measures resulted in an increase in credit loss expense. ComEd and ACE recorded regulatory assets for the incremental credit loss expense based on existing mechanisms. BGE, PECO, Pepco, and DPL also recorded regulatory assets for substantially all the incremental credit loss expense incurred in 2020. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Generation and the Utility Registrants have also incurred direct costs related to COVID-19 consisting primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of their employees. At Generation and PECO, such costs are recorded as Operating and maintenance expense and are excluded from Adjusted (non-GAAP) Operating Earnings. At ComEd, BGE, Pepco, DPL, and ACE, such costs are primarily recorded as regulatory assets. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The estimated impact to Generation's and the Utility Registrants' Net income is approximately $170 million and $75 million for the year ended December 31, 2020, respectively.

To offset the unfavorable impacts from COVID-19, the Registrants identified approximately $250 million in cost savings across Generation and the Utility Registrants in 2020. The cost savings achieved in 2020 were higher than originally anticipated.

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, which Generation repaid 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 24, 2020, Exelon Corporate entered into a credit agreement establishing a $550 million 364-day revolving credit facility to be used as an additional source of short-term liquidity. In addition, the Registrants issued long-term debt of $5.3 billion and were able to successfully complete their planned long-term debt issuances in 2020. See Liquidity and Capital Resources, Note 17 — Debt and Credit Agreements, and Note 6 — Accounts Receivable 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 2020 as a result of COVID-19. See Note 12 — Asset Impairments for additional information related to other impairment assessments in the third 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 an evolving situation that could lead to extended disruption of economic activity in our markets. The Registrants will continue to monitor developments affecting their workforce, customers, and suppliers and will take additional precautions that they determine to be 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 the spread and proliferation of COVID-19 around the world and future developments, which are highly uncertain and cannot be predicted at this time.

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 year ended December 31, 2020 compared to the same period in 2019. For additional information regarding the financial results for the years ended December 31, 2020 and 2019 see the discussions of Results of Operations by Registrant.

	2020	2019	(Unfavorable) Favorable Variance
Exelon	$ 1,963	$ 2,936	$ (973)
Generation	589	1,125	(536)
ComEd	438	688	(250)
PECO	447	528	(81)
BGE	349	360	(11)
PHI	495	477	18
Pepco	266	243	23
DPL	125	147	(22)
ACE	112	99	13
Other[a]	(355)	(242)	(113)

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[a] Primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities, and other financing and investing activities.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. **Net income attributable to common shareholders** decreased by $973 million and diluted earnings per average common share decreased to $2.01 in 2020 from $3.01 in 2019 primarily due to:

- One-time charges and accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024, partially offset by the absence of accelerated depreciation and amortization due to the early retirement of TMI in September 2019;
- Impairment of the New England asset group;
- Payments that ComEd made under the Deferred Prosecution Agreement. See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information;
- Lower capacity revenue;
- Reduction in load due to COVID-19 at Generation;
- Lower realized energy prices;
- Higher nuclear outage days;
- Impact of Generation's annual update to the nuclear ARO for Non-Regulatory Agreement Units;
- Lower net unrealized and realized gains on NDT funds;
- COVID-19 direct costs;
- Lower electric distribution earnings from lower allowed ROE due to a decrease in treasury rates, partially offset by higher rate base at ComEd;

- Higher storm costs related to the June 2020 and August 2020 storms at PECO, net of tax repairs, and related to the August 2020 storm at DPL;
- Unfavorable weather conditions at PECO, DPL Delaware, and ACE; and
- A net increase in depreciation and amortization expense due to ongoing capital expenditures at PECO, BGE, Pepco, DPL, and ACE, partially offset at Generation due to the impact of extending the operating license at Peach Bottom.

The decreases were partially offset by;

- Higher mark-to-market gains;
- Unrealized gains resulting from equity investments without readily determinable fair values that became publicly traded entities in the fourth quarter and were fair valued based on quoted market prices of the stocks as of December 31, 2020;
- Lower operating and maintenance expense at Generation primarily due to previous cost management programs, lower contracting costs, and lower travel costs, partially offset by lower NEIL insurance distributions;
- Lower nuclear fuel costs;
- A tax benefit related to a settlement in the first quarter of 2020, partially offset by the absence of a tax benefit related to certain research and development activities recorded in the fourth quarter of 2019 at Generation; and
- Regulatory rate increases at BGE, DPL, and ACE.

Adjusted (non-GAAP) Operating Earnings. In addition to net income, Exelon evaluates its operating performance using the measure of Adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses, and other specified items. This information is intended to enhance an investor’s overall understanding of year-to-year operating results and provide an indication of Exelon’s baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets, and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies’ presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between Net income attributable to common shareholders as determined in accordance with GAAP and Adjusted (non-GAAP) operating earnings for the year ended December 31, 2020 as compared to 2019:

	For the Years Ended December 31,			
	2020		2019	
(All amounts in millions after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	**$ 1,963**	**$ 2.01**	**$ 2,936**	**$ 3.01**
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $73 and $66, respectively)	(213)	(0.22)	197	0.20
Unrealized (Gains) Losses Related to NDT Fund Investments (net of taxes of $278 and $269, respectively)(a)	(256)	(0.26)	(299)	(0.31)
Asset Impairments (net of taxes of $135 and $56, respectively)(b)	396	0.41	123	0.13
Plant Retirements and Divestitures (net of taxes of $244 and $9, respectively)(c)	718	0.74	118	0.12
Cost Management Program (net of taxes of $14 and $17, respectively)(d)	45	0.05	51	0.05
Litigation Settlement Gain (net of taxes of $7)	—	—	(19)	(0.02)
Asset Retirement Obligation (net of taxes of $16 and $9, respectively)(e)	48	0.05	(84)	(0.09)
Change in Environmental Liabilities (net of taxes of $6 and $8, respectively)	18	0.02	20	0.02
COVID-19 Direct Costs (net of taxes of $19)(f)	50	0.05	—	—
Deferred Prosecution Agreement Payments (net of taxes of $0)(g)	200	0.20	—	—
Acquisition Related Costs (net of taxes of $1)(h)	4	—	—	—
ERP System Implementation Costs (net of taxes of $1)(i)	3	—	—	—
Income Tax-Related Adjustments (entire amount represents tax expense)(j)	71	0.07	5	0.01
Noncontrolling Interests (net of taxes of $19 and $26, respectively)(k)	103	0.11	90	0.09
Adjusted (non-GAAP) Operating Earnings	**$ 3,149**	**$ 3.22**	**$ 3,139**	**$ 3.22**

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 funds, 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 funds were 52.1% and 47.3% for the years ended December 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 2020, reflects an impairment at ComEd in the second quarter of 2020 related to the acquisition of transmission assets and an impairment of the New England asset group in the third quarter of 2020. In 2019, primarily reflects the impairment of equity method investments in certain distributed energy companies. The impact of such impairment net of noncontrolling interest is $0.02.

(c) In 2020, primarily reflects one-time charges and accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024. In 2019, primarily reflects accelerated depreciation and amortization expenses associated with the early retirement of the TMI nuclear facility and certain fossil sites and the loss on the sale of Oyster Creek to Holtec, partially offset by net realized gains related to Oyster Creek's NDT fund investments, a net benefit associated with remeasurements of the TMI ARO, and a gain on the sale of certain wind assets.

(d) Primarily represents reorganization and severance costs related to cost management programs.

(e) Reflects an adjustment to Generation's nuclear ARO for Non-Regulatory Agreement Units resulting from the annual update.
(f) Represents direct costs related to COVID-19 consisting primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of employees.
(g) Reflects the payments made by ComEd under the Deferred Prosecution Agreement, which ComEd entered into on July 17, 2020 with the U.S. Attorney's Office for the Northern District of Illinois.
(h) Reflects costs related to the acquisition of EDF's interest in CENG.
(i) Reflects costs related to a multi-year ERP system implementation.
(j) Primarily reflects the adjustment to deferred income taxes due to changes in forecasted apportionment.
(k) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items. In 2020, primarily related to unrealized gains and losses on NDT fund investments for CENG units. In 2019, primarily related to the impact of unrealized gains on NDT fund investments and the impact of the Generation's annual nuclear ARO update for CENG units, partially offset by the impairment of certain equity investments in distributed energy companies.

Significant 2020 Transactions and Developments

Planned Separation

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies with the resources necessary to best serve customers and sustain long-term investment and operating excellence. The separation gives each company the financial and strategic independence to focus on its specific customer needs, while executing its core business strategy. See Note 26 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information.

Impacts of February 2021 Weather Events and Texas-based Generating Assets Outages

Beginning on February 15, 2021, Generation's Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced periodic outages as a result of historically severe cold weather conditions. In addition, those weather conditions drove increased demand for service, limited the availability of natural gas to fuel power plants, and dramatically increased wholesale power and gas prices.

Exelon and Generation estimate the impact to their Net income for the first quarter of 2021 arising from these market and weather conditions to be approximately $560 million to $710 million. The estimated impact includes favorable results in certain regions within Generation's wholesale gas business. The ultimate impact to Exelon's and Generation's consolidated financial statements may be affected by a number of factors, including final settlement data, the impacts of customer and counterparty credit losses, any state sponsored solutions to address the financial challenges caused by the event, and litigation and contract disputes which may result. Exelon expects to offset between $410 million and $490 million of this impact primarily at Generation through a combination of enhanced revenue opportunities, deferral of selected non-essential maintenance, and primarily one-time cost savings.

See Note 26 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information.

Agreement for Sale of Generation's Solar Business

On December 8, 2020, Generation entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of Generation's solar business, including 360 megawatts of generation in operation or under construction across more than 600 sites across the United States, for a purchase price of $810 million. Completion of the transaction is expected to occur in the first half of 2021. Generation will retain certain solar assets not included in this agreement, primarily Antelope Valley. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Early Retirement of Generation Facilities

In August 2020, Generation announced that it intends to retire the Byron Generating Station in September 2021, Dresden Generating Station in November 2021, and Mystic Units 8 and 9 at the expiration of the cost of service commitment in May 2024. As a result, in the third quarter of 2020, Exelon and Generation recognized a $500 million impairment of its New England asset group and one-time non-cash charges for Byron, Dresden, and Mystic related to materials and supplies inventory reserve adjustments, employee-related costs, and construction work-in-progress impairments, among other items. In addition, there will be ongoing annual financial impacts stemming from shortening the expected economic useful lives of these facilities, primarily related to accelerated depreciation of plant assets (including any ARC) and accelerated amortization of nuclear fuel. Such ongoing charges are excluded from Adjusted (non-GAAP) Operating Earnings.

The following table summarizes the incremental expense recorded for the year ended December 31, 2020 and the estimated amounts of incremental expense expected to be incurred through the retirement dates.

	Actual	Projected[a]			
Income statement expense (pre-tax)	**2020**	**2021**	**2022**	**2023**	**2024**
Depreciation and amortization					
Accelerated depreciation[b]	$ 921	$ 2,070	$ 110	$ 120	$ 50
Accelerated nuclear fuel amortization	60	170	—	—	—
Operating and maintenance					
One-time charges	277	30	10	—	20
Other charges[c]	35	10	10	10	5
Contractual offset[d]	(364)	(475)	—	—	—
Total	$ 929	$ 1,805	$ 130	$ 130	$ 75

(a) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.

(b) Reflects incremental accelerated depreciation of plant assets, including any ARC.

(c) Reflects primarily the net impacts associated with the remeasurement of the ARO for Dresden. See Note 10 – Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

(d) Reflects contractual offset for ARO accretion, ARC depreciation, and net impacts associated with the remeasurement of the ARO for Byron and Dresden. Based on the regulatory agreement with the ICC, decommissioning-related activities are offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income as long as the net cumulative decommissioning-related activities result in a regulatory liability at ComEd. Recognition of a regulatory asset for nuclear decommissioning-related activities at ComEd is not permissible. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. See Note 10 – Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

Deferred Prosecution Agreement

On July 17, 2020, ComEd entered into a Deferred Prosecution Agreement (DPA) with the U.S. Attorney's Office for the Northern District of Illinois (USAO) to resolve the USAO's investigation into ComEd's lobbying activities in the State of Illinois. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the Speaker of the Illinois House of Representatives and the Speaker's associates, with the intent to influence the Speaker's action regarding legislation affecting ComEd's interests. The DPA provides that the USAO will defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period subject to certain obligations of ComEd, including payment to the United States Treasury of $200 million, with $100 million payable within thirty days of the filing of the DPA with the United States District Court for the Northern District of Illinois and an additional $100 million within ninety days of such filing date. The payments will not be recovered in rates or charged to customers, and ComEd will not seek or accept reimbursement or indemnification from any source other than Exelon. See Note 19 — Commitments and Contingencies for additional information.

Utility Distribution Base Rate Case Proceedings

The Utility Registrants file base rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants' current and future financial statements.

The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2020. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these and other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois	April 8, 2019	Electric	$ (6)	$ (17)	8.91 %	December 4, 2019	January 1, 2020
ComEd - Illinois	April 16, 2020	Electric	(11)	(14)	8.38 %	December 9, 2020	January 1, 2021
BGE - Maryland	May 15, 2020 (amended September 11, 2020)	Electric	137	81	9.50 %	December 16, 2020	January 1, 2021
		Natural Gas	91	21	9.65 %		
DPL - Maryland	December 5, 2019 (amended April 23, 2020)	Electric	17	12	9.60 %	July 14, 2020	July 16, 2020
DPL - Delaware	February 21, 2020 (amended October 9, 2020)	Natural Gas	7	2	9.60 %	January 6, 2021	September 21, 2020

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
PECO - Pennsylvania	September 30, 2020	Natural Gas	$ 69	10.95 %	Second quarter of 2021
Pepco - District of Columbia	May 30, 2019 (amended June 1, 2020)	Electric	136	9.7 %	Second quarter of 2021
Pepco - Maryland	October 26, 2020	Electric	110	10.2 %	Second quarter of 2021
DPL - Delaware	March 6, 2020 (amended February 2, 2021)	Electric	23	10.3 %	Third quarter of 2021
ACE - New Jersey	December 9, 2020	Electric	67	10.3 %	Fourth quarter of 2021

Transmission Formula Rates

The following total increases/(decreases) were included in the Utility Registrants' 2020 annual electric transmission formula rate updates. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Registrant	Initial Revenue Requirement Increase/(Decrease)	Annual Reconciliation Decrease	Total Revenue Requirement Increase/(Decrease)	Allowed Return on Rate Base	Allowed ROE
ComEd	$ 18	$ (4)	$ 14	8.17 %	11.50 %
PECO	5	(28)	(23)	7.47 %	10.35 %
BGE	16	(3)	4	7.26 %	10.50 %
Pepco	2	(46)	(44)	7.81 %	10.50 %
DPL	(4)	(40)	(44)	7.20 %	10.50 %
ACE	5	(25)	(20)	7.40 %	10.50 %

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 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's Strategy and Outlook

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies with the resources necessary to best serve customers and sustain long-term investment and operating excellence. The separation gives each company the financial and strategic independence to focus on its specific customer needs, while executing its core business strategy. See Note 26 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information.

In 2021, the businesses remain focused on maintaining industry leading operational excellence, meeting or exceeding their financial commitments, ensuring timely recovery on investments to enable customer benefits, supporting enactment of clean energy policies, and continued commitment to corporate responsibility.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Utility Registrants only invest in rate base where it provides a benefit to customers and the community by improving reliability and the service experience or otherwise meeting customer needs. The Utility Registrants make these investments at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of resources and best practices to achieve improved operational and financial results. Additionally, the Utility Registrants anticipate making significant future investments in smart grid technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation's competitive businesses create value for customers by providing innovative energy solutions and reliable, clean, and affordable energy. Generation's electricity generation strategy is to pursue opportunities that provide stable revenues and match supply to customers. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. Generation's customer-facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Various market, financial, regulatory, legislative and operational factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. One key issue is ensuring the ability to properly value nuclear generation assets in the market, solutions to which Exelon is actively pursuing in a variety of jurisdictions and venues. See ITEM 1A. RISK FACTORS for additional information regarding market and financial factors.

Growth Opportunities

Management continually evaluates growth opportunities aligned with Exelon's businesses, assets and markets, leveraging Exelon's expertise in those areas and offering sustainable returns.

Regulated Energy Businesses. The Utility Registrants anticipate investing approximately $27 billion over the next four years in electric and natural gas infrastructure improvements and modernization projects, including smart grid technology, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $15 billion by the end of 2024. The Utility Registrants invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made at the lowest reasonable cost to customers.

Competitive Energy Businesses. Generation continually assesses the optimal structure and composition of its generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's strategy is to ensure appropriate valuation of its generation assets, in part through public policy efforts, identify and capitalize on opportunities that match supply to customers as a means to provide stable earnings, and identify emerging technologies where strategic investments provide the option for significant future growth or influence in market development.

Other Key Business Drivers and Management Strategies

Utility Rates and Rate Proceedings

The Utility Registrants file 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 results of operations, cash flows, and financial positions. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these regulatory proceedings.

Power Markets

Price of Fuels

The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Section 232 Uranium Petition

On January 16, 2018, two Canadian-owned uranium mining companies with operations in the U.S. jointly submitted a petition to the U.S. Department of Commerce ("DOC") seeking relief under Section 232 of the Trade Expansion Act of 1962 from imports of uranium products, alleging that these imports threaten national security.

The United States Nuclear Fuel Working Group ("Working Group") report was made public on April 23, 2020. The Working Group report states that nuclear power is intrinsically tied to national security, and promises that the U.S. government will take bold actions to strengthen all parts of the nuclear fuel industry in the U.S. It recommends the Agreement Suspending the Antidumping Investigation on Uranium from the Russian Federation (the “Russian Suspension Agreement” or "RSA") be extended and to consider reducing the amount of Russian imports of nuclear fuel. The Russian Suspension Agreement is the historical resolution of a 1991 DOC investigation that found that the Russians had been selling or “dumping” cheap uranium products into the U.S. The RSA has been amended several times in the intervening years to allow Russia to supply limited amounts of uranium products into the U.S. It was set to expire at the end of 2020, but was amended on October 5, 2020 to extend for another 20 years.

The Working Group report should be viewed as policy recommendations that may be implemented by executive agencies, congress, and or regulatory bodies. Exelon and Generation cannot currently predict the outcome of all of the policy changes recommended by the Working Group.

Complaint at FERC Seeking to Alter Capacity Market Default Offer Caps

On February 21, 2019, PJMs Independent Market Monitor (IMM) filed a complaint alleging that the number of performance assessment intervals used to calculate the default offer cap for bids to supply capacity in PJM is too high, resulting in an overstated default offer cap that obviates the need for most sellers to seek unit-specific approval of their offers. The IMM claims that this allows for the exercise of market power. The IMM asks FERC to require PJM to reduce the number of performance assessment intervals used to calculate the opportunity costs of a capacity supplier assuming a capacity obligation. This would, in turn, lower the default offer cap and allow the IMM to review more offers on a unit-specific basis. It is too early to predict the final outcome of this proceeding or its potential financial impact, if any, on Exelon or Generation.

Energy Demand

Load growth at the Utility Registrants is driven by recovery from COVID-19 impacts. ComEd and PECO are projecting modest growth in load of 2.5% and 1.8%, respectively, in 2021 as compared to reduced load in 2020. BGE, Pepco, DPL, and ACE are projecting slower growth as prolonged COVID-19 impacts decrease load by (2.0)%, (0.8)%, (0.9)%, and (2.4)%, respectively, in 2021 compared to 2020.

Retail Competition

Generation’s retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

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 December 31, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% for 2021. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk.

Generation procures natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Approximately 60% of Generation's uranium concentrate requirements from 2021 through 2025 are supplied by three suppliers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's consolidated financial statements.

See Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements and ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Other Legislative and Regulatory Developments

Illinois Clean Energy Progress Act

On March 14, 2019, the Clean Energy Progress Act was introduced in the Illinois General Assembly to preserve Illinois' clean energy choices arising from FEJA and empower the IPA to conduct capacity procurements outside of PJMs base residual auction process, while utilizing the FRR provisions in PJMs tariffs which are still subject to penalties and other obligations under the PJM tariffs. The most significant provisions of the proposed legislation are as follows: (1) it allows the IPA to procure capacity directly from clean energy resources that have previously sold ZECs or RECs, including certain of Generation's nuclear plants in Illinois, or from new clean energy resources, (2) it establishes a goal of achieving 100% carbon-free power in the ComEd service territory by 2032, and (3) it implements reforms to enhance consumer protections in the state's competitive retail electricity and natural gas markets, including Generation's retail customers. Energy legislation has also been proposed by other stakeholders in 2019 and 2020, including renewable resource developers, environmental advocates, and coal-fueled generators. Lawmakers focused their efforts on understanding all of the various legislative proposals with the goal of developing a single comprehensive energy package for ultimate consideration by the General Assembly and Governor Pritzker. Due to the COVID-19 pandemic, the legislative calendar during 2020 was severely curtailed stalling progress on comprehensive energy legislation. The fall 2020 veto session was cancelled. The next opportunity for the General Assembly to consider development of comprehensive energy legislation appears to come during the 2021 spring legislative session. Exelon and Generation will work with legislators and stakeholders and cannot predict the outcome or the potential financial impact, if any, on Exelon or Generation.

Nuclear Powers Act of 2019

On April 12, 2019, the Nuclear Powers America Act of 2019 was introduced to the United States Congress, which expands the current investment tax credit to existing nuclear power plants. The proposed legislation would provide a credit equal to 30% of continued capital investment in certain nuclear energy-related expenditures, including capital expenses and nuclear fuel, starting from tax years 2019 through 2023. Thereafter, the credit rate would be reduced to 26% in 2024, 22% in 2025, and 10% in 2026 and beyond. To qualify for the credit, the plant must be currently operational and must have applied for an operating license renewal before 2026. Exelon and Generation are working with legislators and stakeholders and cannot predict the outcome or the potential financial impact, if any, on Exelon or Generation.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management believes that the accounting policies described below require significant judgment in their application, or incorporate estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional information of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation's ARO associated with decommissioning its nuclear units was $11.9 billion at December 31, 2020. The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple decommissioning outcome scenarios.

As a result of recent nuclear plant retirements in the industry, nuclear operators and third-party service providers are obtaining more information about costs associated with decommissioning activities. At the same time, regulators are gaining more information about decommissioning activities which could result in changes to existing decommissioning requirements. In addition, as more nuclear plants are retired, it is possible that technological advances will be identified that could create efficiencies and lead to a reduction in decommissioning costs. The availability of NDT funds could impact the timing of the decommissioning activities. Additionally, certain factors such as changes in regulatory requirements during plant operations or the profitability of a nuclear plant could impact the timing of plant retirements. These factors could result in material changes to Generation's current estimates as more information becomes available and could change the timing of plant retirements and the probability assigned to the decommissioning outcome scenarios.

The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing and/or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the following methodologies and significant estimates and assumptions:

Decommissioning Cost Studies. Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the expected costs (in current year dollars) and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years, unless circumstances warrant more frequent updates. As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle.

Cost Escalation Factors. Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal, and other costs. All of the nuclear AROs are adjusted each year for the updated cost escalation factors.

Probabilistic Cash Flow Models. Generation's probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning cost levels, decommissioning approaches, and timing of plant shutdown on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. The assumed decommissioning scenarios include the following three alternatives: (1) DECON which assumes decommissioning activities begin shortly after the cessation of operation, (2) Shortened SAFSTOR generally has a 30-year delay prior to onset of decommissioning activities, and (3) SAFSTOR which assumes the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated generally within 60 years after cessation of operations. In each decommissioning scenario, spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

The actual decommissioning approach selected once a nuclear facility is shutdown will be determined by Generation at the time of shutdown and may be influenced by multiple factors including the funding status of the NDT fund at the time of shutdown.

The assumed plant shutdown timing scenarios include the following four alternatives: (1) the probability of operating through the original 40-year nuclear license term, (2) the probability of operating through an extended

60-year nuclear license term (regardless of whether such 20-year license extension has been received for each unit), (3) the probability of a second, 20-year license renewal for some nuclear units, and (4) the probability of early plant retirement for certain sites due to changing market conditions and regulatory environments. As power market and regulatory environment developments occur, Generation evaluates and incorporates, as necessary, the impacts of such developments into its nuclear ARO assumptions and estimates.

Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal. Generation currently assumes DOE will begin accepting SNF in 2035. The SNF acceptance date assumption is based on management's estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage. For additional information regarding the estimated date when DOE will begin accepting SNF, see Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

Discount Rates. The probability-weighted estimated future cash flows for the various assumed scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. Generation initially recognizes an ARO at fair value and subsequently adjusts it for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions. The ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. Increases in the ARO as a result of upward revisions in estimated undiscounted cash flows are considered new obligations and are measured using a current CARFR as the increase creates a new cost layer within the ARO. Any decrease in the estimated undiscounted future cash flows relating to the ARO are treated as a modification of an existing ARO cost layer and, therefore, is measured using the average historical CARFR rates used in creating the initial ARO cost layers. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFR, the obligation would increase from approximately $11.9 billion to approximately $15.0 billion.

The following table illustrates the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO (dollars in millions):

Change in the CARFR applied to the annual ARO update		(Decrease) Increase to ARO at December 31, 2020
2019 CARFR rather than the 2020 CARFR	$	(370)
2020 CARFR increased by 50 basis points		(390)
2020 CARFR decreased by 50 basis points		490

ARO Sensitivities. Changes in the assumptions underlying the ARO could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions may correspondingly change.

The following table illustrates the effects of changing certain ARO assumptions while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption		Increase to ARO at December 31, 2020
Cost escalation studies		
Uniform increase in escalation rates of 50 basis points	$	2,560
Probabilistic cash flow models		
Increase the estimated costs to decommission the nuclear plants by 10 percent		1,050
Increase the likelihood of the DECON scenario by 10 percent and decrease the likelihood of the SAFSTOR scenario by 10 percent(a)		610
Shorten each unit's probability weighted operating life assumption by 10 percent(b)		1,690
Extend the estimated date for DOE acceptance of SNF to 2040		280

(a) Excludes any sites in which management has committed to a specific decommissioning approach.
(b) Excludes any retired sites.

See Note 1 — Significant Accounting Policies, Note 7 — Early Plant Retirements and Note 10 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for nuclear AROs.

Goodwill (Exelon, ComEd, and PHI)

As of December 31, 2020, Exelon’s $6.7 billion carrying amount of goodwill consists primarily of $2.6 billion at ComEd and $4 billion at PHI. These entities are required to perform an assessment for possible impairment of their goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting units below their carrying amount. A reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is assessed for impairment. ComEd has a single operating segment and reporting unit. PHI’s operating segments and reporting units are Pepco, DPL, and ACE. See Note 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information. Exelon's and ComEd’s goodwill has been assigned entirely to the ComEd reporting unit. Exelon's and PHI’s goodwill has been assigned to the Pepco, DPL, and ACE reporting units in the amounts of $2.1 billion, $1.4 billion, and $0.5 billion, respectively. See Note 13 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. As part of the qualitative assessments, Exelon, ComEd, and PHI evaluate, among other things, management's best estimate of projected operating and capital cash flows for their businesses, outcomes of recent regulatory proceedings, changes in certain market conditions, including the discount rate and regulated utility peer EBITDA multiples, and the passing margin from their last quantitative assessments performed.

Application of the goodwill impairment assessment requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, and projected operating and capital cash flows for ComEd’s, Pepco's, DPL's, and ACE's businesses and the fair value of debt.

While the 2020 annual assessments indicated no impairments, certain assumptions used in the assessment are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon’s, ComEd's, or PHI’s goodwill, which could be material.

See Note 1 — Significant Accounting Policies and Note 13 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Contract Assets and Liabilities (Exelon, Generation, and PHI)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired and the electricity contracts Exelon acquired as part of the PHI merger. The initial amount recorded represents the fair value of the contracts at the time of acquisition. At Exelon and PHI, offsetting regulatory assets or liabilities were also recorded for those energy contract costs that are probable of recovery or refund through customer rates. The unamortized energy contract assets and liabilities and any corresponding regulatory assets or liabilities, respectively, are amortized over the life of the contract in relation to the expected realization of the underlying cash flows. Amortization of the unamortized energy contract assets and liabilities is recorded through purchased power and fuel expense or operating revenues, depending on the nature of the underlying contract. See Note 3 — Regulatory Matters and Note 13 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Impairment of Long-Lived Assets (All Registrants)

All Registrants 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 potential impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, an asset remaining idle for more than a short period of time, specific regulatory disallowance, advances in technology, plans to dispose of a long-lived asset significantly before the end of its useful life, and financial distress of a third party for assets contracted with them on a long-term basis, among others.

The review of long-lived assets and asset groups for impairment utilizes significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power and purchases of fuel and the expected operations of assets. 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. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by the evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units as well as the associated intangible assets or liabilities recorded on the balance sheet. The cash flows from the generating units are generally evaluated at a regional portfolio level with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generating assets (typically contracted renewables). For such assets the financial viability of the third party, including the impact of bankruptcy on the contract, may be a significant assumption in the assessment.

On a quarterly basis, Generation assesses its long-lived assets or asset groups for indicators of impairment. If indicators are present for a long-lived asset or asset group, a comparison of the undiscounted expected future cash flows to the carrying value is performed. When the undiscounted cash flow analysis indicates the carrying value of 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 of the long-lived asset or asset group is dependent upon a market participant's view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances often do not occur as expected resulting in differences between prospective financial information and actual results, which may be material. The determination of fair value is driven by both internal assumptions that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources.

See Note 12 — Asset Impairments of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment assessments.

Depreciable Lives of Property, Plant, and Equipment (All Registrants)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. These assets are generally depreciated 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 heterogeneous assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The estimation of asset useful lives requires management judgment, supported by formal depreciation studies of historical asset retirement experience. Depreciation studies are generally completed every five years, or more frequently if required by a rate regulator or if an event, regulatory action, or change in retirement patterns indicate an update is necessary.

For the Utility Registrants, depreciation studies generally serve as the basis for amounts allowed in customer rates for recovery of depreciation costs. Generally, the Utility Registrants adjust their depreciation rates for financial reporting purposes concurrent with adjustments to depreciation rates reflected in customer rates, unless the depreciation rates reflected in customer rates do not align with management's judgment as to an appropriate estimated useful life or have not been updated on a timely basis. Depreciation expense and customer rates for ComEd, BGE, Pepco, DPL, and ACE include an estimate of the future costs of dismantling and removing plant from service upon retirement. See Note 3 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for information regarding regulatory liabilities and assets recorded by ComEd, BGE, Pepco, DPL, and ACE related to removal costs.

PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method. Estimates for such removal costs are also evaluated in the periodic depreciation studies.

At Generation, along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of its generating facilities and reassesses the reasonableness of estimated useful lives whenever events or changes in circumstances warrant. When a determination has been made that an asset will be retired before the end of its current estimated useful life, depreciation provisions will be accelerated to reflect the shortened estimated useful life, which could have a material unfavorable impact on Exelon's and Generation's future results of operations. See Note 7 — Early Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information.

Changes in estimated useful lives of electric generation assets and of electric and natural gas transmission and distribution assets could have a significant impact on the Registrants' future results of operations. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant, and equipment of the Registrants.

Defined Benefit Pension and Other Postretirement Employee Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and OPEB plans for substantially all current employees. The measurement of the plan obligations and costs of providing benefits involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is affected by several assumptions including the discount rate, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon's contributions, the rate of compensation increases, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations.

Pension and OPEB plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity, and hedge funds.

Expected Rate of Return on Plan Assets. In determining the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectation regarding future long-term capital market performance, weighted by Exelon's target asset class allocations. Exelon calculates the amount of expected return on pension and OPEB plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For OPEB plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV.

Discount Rate. The discount rates are determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and OPEB obligations. The spot rates are used to discount the estimated future benefit distribution amounts under the pension and OPEB plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

Mortality. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. Exelon's mortality assumption utilizes the SOA 2019 base table (Pri-2012) and MP-2020 improvement scale adjusted to use Proxy SSA ultimate improvement rates.

Sensitivity to Changes in Key Assumptions. The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

	Actual Assumption					
Actuarial Assumption	**Pension**	**OPEB**	**Change in Assumption**	**Pension**	**OPEB**	**Total**
Change in 2020 cost:						
Discount rate[(a)]	3.34%	3.31%	0.5%	$ (52)	$ (14)	$ (66)
	3.34%	3.31%	(0.5)%	70	15	85
EROA	7.00%	6.69%	0.5%	(91)	(12)	(103)
	7.00%	6.69%	(0.5)%	91	12	103
Change in benefit obligation at December 31, 2020:						
Discount rate[(a)]	2.58%	2.51%	0.5%	(1,410)	(268)	(1,678)
	2.58%	2.51%	(0.5)%	1,631	309	1,940

(a) In general, the discount rate will have a larger impact on the pension and OPEB cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon utilizes a liability-driven investment strategy for its pension asset portfolio. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

See Note 1 — Significant Accounting Policies and Note 15 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and OPEB plans.

Regulatory Accounting (Exelon and Utility Registrants)

For their regulated electric and gas operations, Exelon and the Utility Registrants reflect the effects of cost-based rate regulation in their financial statements, which is required for entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) revenue or gains that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. If it is concluded in a future period that a separable portion of operations no longer meets the criteria discussed above, Exelon and the Utility Registrants would be required to eliminate any associated regulatory assets and liabilities and the impact, which could be material, would be recognized in the Consolidated Statements of Operations and Comprehensive Income.

The following table illustrates the gains (losses) that could result from the elimination of regulatory assets and liabilities and charges against OCI (dollars in millions before taxes) related to deferred costs associated with Exelon's pension and OPEB plans that are recorded as regulatory assets in Exelon's Consolidated Balance Sheets:

December 31, 2020	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Gain (loss)	$ 79	$ 4,664	$ (177)	$ 490	$ (798)	$ (94)	$ 260	$ (152)
Charge against OCI[(a)]	$ 3,984	$ —	$ —	$ —	$ —	$ —	$ —	$ —

(a) Exelon's charge against OCI (before taxes) consists of up to $2.7 billion, $481 million, $193 million, $387 million, $188 million, and $91 million related to ComEd's, BGE's, PHI's, Pepco's, DPL's, and ACE's respective portions of the deferred costs associated with Exelon's pension and OPEB plans. Exelon also has a net regulatory liability of $(36) million (before taxes) related to PECO's portion of the deferred costs associated with Exelon's OPEB plans that would result in an increase in OCI if reversed.

See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon and the Utility Registrants.

For each regulatory jurisdiction in which they conduct business, Exelon and the Utility Registrants assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or refund at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in each Registrant's jurisdictions, and factors such as changes in applicable regulatory and political environments. If the assessments and estimates made by Exelon and the Utility Registrants for regulatory assets and regulatory liabilities are ultimately different than actual regulatory outcomes, the impact in their consolidated financial statements could be material.

Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ICC-approved electric distribution and energy efficiency formula rates for ComEd, and FERC transmission formula rate tariffs for the Utility Registrants.

Accounting for Derivative Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, foreign currency exchange risk, and interest rate risk related to ongoing business operations. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing market liquidity as well as determining whether a contract has one or more underlyings and one or more notional quantities. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance, could result in previously excluded contracts becoming in scope of new authoritative guidance.

All derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, NPNS. Derivatives entered into for economic hedging and for proprietary trading purposes are recorded at fair value through earnings. For economic hedges that are not designated for hedge accounting for the Utility Registrants, changes in the fair value each period are generally recorded with a corresponding offsetting regulatory asset or liability given likelihood of recovering the associated costs through customer rates.

NPNS. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated by Generation as NPNS transactions, which are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for the NPNS requires judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as NPNS are recognized when the underlying physical transaction is completed. Contracts that qualify for the NPNS are those for which 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 the contract is not financially settled on a net basis. The contracts that ComEd has entered into with suppliers as part of ComEd's energy procurement process, PECO's full requirement contracts under the PAPUC-approved DSP program, most of PECO's natural gas supply agreements, all of BGE's full requirement contracts and natural gas supply agreements that are derivatives, and certain Pepco, DPL, and ACE full requirement contracts qualify for and are accounted for under the NPNS.

Commodity Contracts. Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of the authoritative guidance, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. Under the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value.

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 generally 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. The price quotations reflect the average of the bid-ask mid-point from markets that the Registrants believe 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. The Registrant's derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using models that consider inputs such as contract terms, including maturity, and market parameters, and 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, the model inputs are generally observable. Such instruments are categorized in Level 2.

For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs and are categorized in Level 3.

The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of nonperformance and credit risk to date have generally not been material to the financial statements.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 18 — Fair Value of Financial Assets and Liabilities and Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (All Registrants)

Significant management judgment is required in determining the Registrants' provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. The Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of tax benefits to be recorded in the Registrants' consolidated financial statements.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. The Registrants also assess negative evidence, such as the expiration of historical operating loss or tax credit carryforwards, that could indicate the Registrant's inability to realize its deferred tax assets. Based on the combined assessment, the Registrants record valuation allowances for deferred tax assets when it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including future changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Accounting for Loss Contingencies (All Registrants)

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amount recorded may differ from the actual expense incurred when the uncertainty is resolved. Such difference could have a significant impact in the Registrants' consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work and changes in technology, regulations, and the requirements of local governmental authorities. Annual studies and/or reviews are conducted at ComEd, PECO, BGE, and DPL to determine future remediation requirements for MGP sites and estimates are adjusted accordingly. In addition, periodic reviews are performed at each of the Registrants to assess the adequacy of other environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant impact in the Registrants' consolidated financial statements. See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Including Personal Injury Claims. The Registrants are self-insured for general liability, automotive liability, workers' compensation, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material impact in the Registrants' consolidated financial statements.

Revenue Recognition (All Registrants)

Sources of Revenue and Determination of Accounting Treatment. The Registrants earn revenues from various business activities including: the sale of power and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail); the sale and delivery of power and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable authoritative guidance. The Registrants primarily apply the Revenue from Contracts with Customers, Derivative and ARP guidance to recognize revenue as discussed in more detail below.

Revenue from Contracts with Customers. The Registrants recognize revenues in the period in which the performance obligations within contracts with customers are satisfied, which generally occurs when power, natural gas, and other energy-related commodities are physically delivered to the customer. Transactions of the Registrants within the scope of Revenue from Contracts with Customers generally include non-derivative agreements, contracts that are designated as NPNS, sales to utility customers under regulated service tariffs, and spot-market energy commodity sales, including settlements with ISOs.

The determination of Generation’s and the Utility Registrants' retail power and natural gas sales to individual customers is based on systematic readings of customer meters, generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities’ customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, revenues may fluctuate monthly as a result of customers electing to use an alternate supplier, since unbilled commodity revenues are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date also impact the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information.

Derivative Revenues. The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that are accounted for as derivatives. These derivative transactions primarily relate to commodity price risk management activities. Mark-to-market revenues and expenses include: inception gains or losses on new transactions where the fair value is observable, unrealized gains and losses from changes in the fair value of open contracts, and realized gains and losses.

Alternative Revenue Program Accounting. Certain of the Utility Registrants’ ratemaking mechanisms qualify as ARPs if they (i) are established by a regulatory order and allow for automatic adjustment to future rates, (ii) provide for additional revenues (above those amounts currently reflected in the price of utility service) that are objectively determinable and probable of recovery, and (iii) allow for the collection of those additional revenues within 24 months following the end of the period in which they were recognized. For mechanisms that meet these criteria, which include the Utility Registrants’ formula rate mechanisms and revenue decoupling mechanisms, the Utility Registrants adjust revenue and record an offsetting regulatory asset or liability once the condition or event allowing additional billing or refund has occurred. The ARP revenues presented in the Utility Registrants’ Consolidated Statements of Operations and Comprehensive Income include both: (i) the recognition of “originating” ARP revenues (when the regulator-specified condition or event allowing for additional billing or refund has occurred) and (ii) an equal and offsetting reversal of the “originating” ARP revenues as those amounts are reflected in the price of utility service and recognized as Revenue from Contracts with Customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, distributed generation rebates, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco, and DPL record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC and/or DCPSC in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL, and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in accordance with their formula rate mechanisms. Estimates of the current year revenue requirement are based on actual and/or forecasted costs and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred, investments made, allowed ROE, and actions by regulators or courts.

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

Allowance for Credit Losses on Customer Accounts Receivable (Utility Registrants)

Utility Registrants estimate the allowance for credit losses on customer receivables by applying loss rates developed specifically for each company based on historical loss experience, current conditions, and forward-looking risk factors to the outstanding receivable balance by customer risk segment. Risk segments represent a group of customers with similar forward-looking credit quality indicators and risk factors that are comprised based on various attributes, including delinquency of their balances and payment history and represent expected, future customer behavior. Loss rates applied to the accounts receivable balances are based on a historical average of charge-offs as a percentage of accounts receivable in each risk segment. The Utility Registrants' customer accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. Utility Registrants' customer accounts are written off consistent with approved regulatory requirements. Utility Registrants' allowances for credit losses will continue to be affected by changes in volume, prices, and economic conditions as well as changes in ICC, PAPUC, MDPSC, DCPSC, DPSC, and NJBPU regulations.

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.

	2020	2019	(Unfavorable) Favorable Variance
Operating revenues	$ 17,603	$ 18,924	$ (1,321)
Purchased power and fuel expense	9,585	10,856	1,271
Revenues net of purchased power and fuel expense	8,018	8,068	(50)
Other operating expenses			
Operating and maintenance	5,168	4,718	(450)
Depreciation and amortization	2,123	1,535	(588)
Taxes other than income taxes	482	519	37
Total other operating expenses	7,773	6,772	(1,001)
Gain on sales of assets and businesses	11	27	(16)
Operating income	256	1,323	(1,067)
Other income and (deductions)			
Interest expense	(357)	(429)	72
Other, net	937	1,023	(86)
Total other income and (deductions)	580	594	(14)
Income before income taxes	836	1,917	(1,081)
Income taxes	249	516	267
Equity in losses of unconsolidated affiliates	(8)	(184)	176
Net income	579	1,217	(638)
Net (loss) income attributable to noncontrolling interests	(10)	92	(102)
Net income attributable to membership interest	$ 589	$ 1,125	$ (536)

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. **Net income attributable to membership interest** decreased by $536 million primarily due to:

- One-time charges and accelerated depreciation and amortization associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024, partially offset by the absence of accelerated depreciation and amortization due to the early retirement of TMI in September 2019;

- Impairment of the New England asset group;
- Lower capacity revenue;
- Reduction in load due to COVID-19;

- Lower realized energy prices;
- Higher nuclear outage days;
- Impact of Generation's annual update to the nuclear ARO for Non-regulatory Agreement Units;
- Lower net unrealized and realized gains on NDT funds;
- COVID-19 direct costs; and

The decreases were partially offset by:

- Higher mark-to-market gains;
- Unrealized gains resulting from equity investments without readily determinable fair values that became publicly traded entities in the fourth quarter of 2020 and were fair valued based on quoted market prices of the stocks as of December 31, 2020;
- Lower operating and maintenance expense primarily due to previous cost management programs, lower contracting costs, and lower travel costs partially offset by lower NEIL insurance distributions;
- Lower nuclear fuel costs;
- Lower depreciation and amortization expense due to the impact of extending the operating license at Peach Bottom;
- A tax benefit related to a settlement in the first quarter of 2020, partially offset by the absence of a tax benefit related to certain research and development activities recorded in the fourth quarter of 2019.

Revenues Net of Purchased Power and Fuel Expense. The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Generation's five reportable segments are Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions. See Note 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on these reportable segments.

The following business activities are not allocated to a region and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to overall operating revenues or results of operations. Further, the following activities are not allocated to a region and are reported in Other: accelerated nuclear fuel amortization associated with nuclear decommissioning; and other miscellaneous revenues.

Generation evaluates the operating performance of electric business activities using the measure of RNF. Operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy, and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.

For the years ended December 31, 2020 compared to 2019, RNF by region were as follows. See Note 5 - Segment Information of the Combined Notes to the Consolidated Financial Statements for additional information on Purchase power and fuel expense for Generation's reportable segments.

			2020 vs. 2019	
	2020	**2019**	**Variance**	**% Change**
Mid-Atlantic[a]	$ 2,204	$ 2,655	$ (451)	(17.0)%
Midwest[b]	2,902	2,962	(60)	(2.0)%
New York	997	1,094	(97)	(8.9)%
ERCOT	426	308	118	38.3 %
Other Power Regions	665	620	45	7.3 %
Total electric revenues net of purchased power and fuel expense	7,194	7,639	(445)	(5.8)%
Mark-to-market gains (losses)	295	(215)	510	237.2 %
Other	529	644	(115)	(17.9)%
Total revenue net of purchased power and fuel expense	$ 8,018	$ 8,068	$ (50)	(0.6)%

(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)	2020	2019	2020 vs. 2019 Variance	2020 vs. 2019 % Change
Nuclear Generation[a]				
Mid-Atlantic	52,202	58,347	(6,145)	(10.5)%
Midwest	96,322	94,890	1,432	1.5 %
New York	26,561	28,088	(1,527)	(5.4)%
Total Nuclear Generation	175,085	181,325	(6,240)	(3.4)%
Fossil and Renewables				
Mid-Atlantic	2,206	2,884	(678)	(23.5)%
Midwest	1,240	1,374	(134)	(9.8)%
New York	4	5	(1)	(20.0)%
ERCOT	11,982	13,572	(1,590)	(11.7)%
Other Power Regions	11,121	11,476	(355)	(3.1)%
Total Fossil and Renewables	26,553	29,311	(2,758)	(9.4)%
Purchased Power				
Mid-Atlantic	22,487	14,790	7,697	52.0 %
Midwest	770	1,424	(654)	(45.9)%
ERCOT	5,636	4,821	815	16.9 %
Other Power Regions	51,079	48,673	2,406	4.9 %
Total Purchased Power	79,972	69,708	10,264	14.7 %
Total Supply/Sales by Region[c]				
Mid-Atlantic[b]	76,895	76,021	874	1.1 %
Midwest[b]	98,332	97,688	644	0.7 %
New York	26,565	28,093	(1,528)	(5.4)%
ERCOT	17,618	18,393	(775)	(4.2)%
Other Power Regions	62,200	60,149	2,051	3.4 %
Total Supply/Sales by Region	281,610	280,344	1,266	0.5 %

(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.
(c) Reflects a decrease in load due to COVID-19.

For the years ended December 31, 2020 compared to 2019 changes in RNF by region were as follows:

	2020 vs. 2019	
	(Decrease)/Increase	Description
Mid-Atlantic	$ (451)	• decreased revenue due to the permanent cease of generation operations at TMI in the third quarter of 2019 • decreased capacity revenues • lower realized energy prices, partially offset by • increase in newly contracted load offset by impacts of COVID-19 • increased ZEC revenues due to the approval of the NJ ZEC program in the second quarter of 2019
Midwest	(60)	• decreased capacity revenues • lower realized energy prices • decreased load due to COVID-19 offset by an increase in total ISO sales, partially offset by • decreased nuclear outage days
New York	(97)	• increased nuclear outage days • decreased ZEC revenues due to increased outage days • lower realized energy prices • decreased load due to COVID-19 offset by newly contracted load, partially offset by • increased capacity revenues
ERCOT	118	• lower procurement costs for owned and contracted assets • higher portfolio optimization, partially offset by • lower realized energy prices
Other Power Regions	45	• higher portfolio optimization • increase in newly contracted load offset by impacts of COVID-19, partially offset by • decreased capacity revenues • lower realized energy prices
Mark-to-market[(a)]	510	• gains on economic hedging activities of $295 million in 2020 compared to losses of $215 million in 2019
Other	(115)	• increase in accelerated nuclear fuel amortization associated with announced early plant retirements • decreased revenue related to the energy efficiency business
Total	$ (50)	

(a) See Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on mark-to-market gains and 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.

	2020	2019
Nuclear fleet capacity factor	95.4 %	95.7 %
Refueling outage days	260	209
Non-refueling outage days	19	51

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

	2020 vs. 2019 Increase (Decrease)
Asset Impairments	$ 499
ARO update	125
Nuclear refueling outage costs, including the co-owned Salem plants	60
Insurance	52
COVID-19 direct costs	46
Litigation settlements	26
Change in environmental liabilities	18
Credit loss expense[(a)]	16
Accretion expense	14
Plant retirements and divestitures	(8)
Pension and non-pension postretirement benefits expense	(19)
Corporate allocations	(35)
Travel costs	(38)
Other	(71)
Labor, other benefits, contracting, and materials[(b)]	(235)
Total increase	$ 450

(a) Increased credit loss expense including impacts from COVID-19.
(b) Primarily reflects decreased costs related to the permanent cease of generation operations at TMI, lower labor costs resulting from previous cost management programs, and decreased contracting costs.

Depreciation and amortization expense for the year ended December 31, 2020 compared to the same period in 2019 increased primarily due to the accelerated depreciation and amortization associated with Generation's decision to early retire the Byron and Dresden nuclear facilities, partially offset by the permanent cease of generation operations at TMI.

Taxes other than income taxes for the year ended December 31, 2020 compared to the same period in 2019 decreased primarily due to decreased sales and power usage.

Gain on sales of assets and businesses for the year ended December 31, 2020 compared to the same period in 2019 decreased primarily due to Generation's gain on sale of certain wind assets in 2019 partially offset by the loss on sale of Oyster Creek.

Other, net for the year ended December 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 gains on NDT funds[a]	$ 391	$ 411
Net realized gains on sale of NDT funds[a]	70	253
Interest and dividend income on NDT funds[a]	90	110
Contractual elimination of income tax expense[b]	180	216
Unrealized gains from equity investments[c]	186	—
Other	20	33
Total other, net	$ 937	$ 1,023

(a) Unrealized gains, realized gains, and interest and dividend income on the NDT funds are associated with the Non-Regulatory Agreement Units.
(b) Contractual elimination of income tax expense is associated with the income taxes on the NDT funds of the Regulatory Agreement Units.
(c) Unrealized gains resulting from equity investments without readily determinable fair values that became publicly traded entities in the fourth quarter of 2020 and were fair valued based on quoted market prices of the stocks as of December 31, 2020.

Interest Expense for the year ended December 31, 2020 compared to the same period in 2019 decreased primarily due to the redemption of long-term debt in 2020.

Effective income tax rates were 29.8% and 26.9% for the years ended December 31, 2020 and 2019, respectively. The change in 2020 is primarily related to one-time income tax settlements partially offset by the absence of research and development refund claims. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Equity in losses of unconsolidated affiliates for the year ended December 31, 2020 compared to the same period in 2019 increased primarily due to the impairment of equity method investments in certain distributed energy companies in the third quarter of 2019.

Net income attributable to noncontrolling interests for the year ended December 31, 2020 compared to the same period in 2019 decreased primarily due to lower unrealized losses on NDT fund investments for CENG.

Results of Operations—ComEd

	2020	2019	Favorable (Unfavorable) Variance
Operating revenues	$ 5,904	$ 5,747	$ 157
Operating expenses			
Purchased power expense	1,998	1,941	(57)
Operating and maintenance	1,520	1,305	(215)
Depreciation and amortization	1,133	1,033	(100)
Taxes other than income taxes	299	301	2
Total operating expenses	4,950	4,580	(370)
Gain on sales of assets	—	4	(4)
Operating income	954	1,171	(217)
Other income and (deductions)			
Interest expense, net	(382)	(359)	(23)
Other, net	43	39	4
Total other income and (deductions)	(339)	(320)	(19)
Income before income taxes	615	851	(236)
Income taxes	177	163	(14)
Net income	$ 438	$ 688	$ (250)

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. **Net income** decreased by $250 million primarily due to payments that ComEd made under the Deferred Prosecution Agreement, an impairment charge resulting from acquisition of transmission assets, and lower allowed electric distribution ROE due to a decrease in treasury rates, partially offset by higher electric distribution formula rate earnings (reflecting the impacts of higher rate base). See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information related to the Deferred Prosecution Agreement.

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

	2020 vs. 2019
	Increase
Energy efficiency	$ 37
Electric distribution	36
Transmission	2
Other	29
	104
Regulatory required programs	53
Total increase	$ 157

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. Operating revenues are not impacted by abnormal weather, usage per customer, or number of customers as a result of revenue decoupling mechanisms implemented pursuant to FEJA.

Energy Efficiency Revenue. FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under FEJA, energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. Energy efficiency revenue increased for the year ended December 31, 2020, as compared to the same period in 2019, primarily due to increased regulatory asset amortization which is fully recoverable. See Depreciation and amortization expense discussions below and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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. During the year ended December 31, 2020, as compared to the same period in 2019, electric distribution revenue increased due to the impact of higher rate base and higher fully recoverable costs, offset by lower allowed ROE due to a decrease in treasury rates. See Note 3 — 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. During the year ended December 31, 2020, as compared to the same period in 2019, transmission revenues remained relatively consistent. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other Revenue primarily includes assistance provided to other utilities through mutual assistance programs. The increase in Other revenue for the year ended December 31, 2020, as compared to the same period in 2019, primarily reflects mutual assistance revenues associated with storm restoration efforts.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as recoveries under the credit loss expense tariff, environmental costs associated with MGP sites, and costs related to electricity, ZEC, and REC procurement. The riders are designed to provide full and current cost recovery. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries as ComEd remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, ComEd acts as the billing agent and therefore does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from ComEd, ComEd is permitted to recover the electricity, ZEC, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power expense related to the electricity, ZECs, and RECs.

See Note 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The increase of $57 million for the year ended December 31, 2020, as compared to the same period in 2019, in **Purchased power expense** is offset in Operating revenues as part of regulatory required programs.

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

	2020 vs. 2019 Increase (Decrease)
Deferred Prosecution Agreement payments[a]	$ 200
BSC costs	20
Labor, other benefits, contracting, and materials	7
Pension and non-pension postretirement benefits expense	5
Storm-related costs[b]	(12)
Other[c]	(4)
	216
Regulatory required programs[d]	(1)
Total increase	$ 215

(a) See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.
(b) For the year ended December 31, 2020, the decrease primarily reflects lower storm costs as a result of the August 2020 storm costs being reclassified to a regulatory asset.
(c) For the year ended December 31, 2020, the decrease primarily reflects lower travel costs offset by an impairment charge related to acquisition of transmission assets.
(d) ComEd is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through a rider mechanism.

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

	2020 vs. 2019 Increase
Regulatory asset amortization[a]	$ 64
Depreciation and amortization expense[b]	36
Total increase	$ 100

(a) Includes amortization of ComEd's energy efficiency formula rate regulatory asset and amortization related to the August 2020 storm regulatory asset.
(b) Reflects ongoing capital expenditures.

Interest Expense, net increased $23 million for the year ended December 31, 2020, as compared to the same period in 2019, primarily due to the issuance of debt in February 2020.

Effective income tax rates for the years ended December 31, 2020 and 2019, were 28.8% and 19.2%, respectively. See Note 14 — 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

	2020	2019	(Unfavorable) Favorable Variance
Operating revenues	$ 3,058	$ 3,100	$ (42)
Operating expenses			
Purchased power and fuel expense	1,018	1,029	11
Operating and maintenance	975	861	(114)
Depreciation and amortization	347	333	(14)
Taxes other than income taxes	172	165	(7)
Total operating expenses	2,512	2,388	(124)
Gain on sales of assets	—	1	(1)
Operating income	546	713	(167)
Other income and (deductions)			
Interest expense, net	(147)	(136)	(11)
Other, net	18	16	2
Total other income and (deductions)	(129)	(120)	(9)
Income before income taxes	417	593	(176)
Income taxes	(30)	65	95
Net income	$ 447	$ 528	$ (81)

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. **Net income** decreased by $81 million primarily due to unfavorable weather conditions, higher storm costs due to the June and August 2020 storms net of tax repairs, increased depreciation and amortization expense, and increased interest expense, partially offset by favorable volume and an increase in the tax repairs deduction.

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

	2020 vs. 2019		
	(Decrease) Increase		
	Electric	Gas	Total
Weather	$ (29)	$ (21)	$ (50)
Volume	12	(3)	9
Pricing	2	6	8
Transmission	11	—	11
Other	(7)	(1)	(8)
	(11)	(19)	(30)
Regulatory required programs	65	(77)	(12)
Total increase (decrease)	$ 54	$ (96)	$ (42)

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. For the year ended December 31, 2020 compared to the same period in 2019, Operating revenues related to weather decreased due to 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 years ended December 31, 2020 compared to the same period in 2019 and normal weather consisted of the following:

Heating and Cooling Degree-Days	For the Years Ended December 31, 2020	2019	Normal	% Change 2020 vs. 2019	2019 vs. Normal
Heating Degree-Days	3,959	4,307	4,437	(8.1)%	(10.8)%
Cooling Degree-Days	1,521	1,610	1,423	(5.5)%	6.9 %

Volume. Electric volume, exclusive of the effects of weather, for the year ended December 31, 2020 compared to the same period in 2019, increased due to an increase in usage for residential customers during COVID-19 further increased by customer growth. Natural gas volume for the year ended December 31, 2020 compared to the same period in 2019, decreased on a net basis due to a decrease in usage for the commercial and industrial natural gas classes during COVID-19.

Electric Retail Deliveries to Customers (in GWhs)	2020	2019	% Change 2020 vs. 2019	Weather - Normal % Change[(b)]
Retail Deliveries[(a)]				
Residential	14,041	13,650	2.9 %	5.6 %
Small commercial & industrial	7,210	7,983	(9.7)%	(8.2)%
Large commercial & industrial	13,669	14,958	(8.6)%	(8.5)%
Public authorities & electric railroads	575	725	(20.7)%	(20.7)%
Total electric retail deliveries	35,495	37,316	(4.9)%	(3.5)%

(a) Reflects delivery volumes and revenue 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.

Number of Electric Customers	As of December 31, 2020	2019
Residential	1,508,622	1,494,462
Small commercial & industrial	154,421	154,000
Large commercial & industrial	3,101	3,104
Public authorities & electric railroads	10,206	10,039
Total	1,676,350	1,661,605

Natural Gas Deliveries to customers (in mmcf)	2020	2019	% Change 2020 vs. 2019	Weather - Normal % Change[(b)]
Retail Deliveries[(a)]				
Residential	38,272	40,196	(4.8)%	1.6 %
Small commercial & industrial	19,341	23,828	(18.8)%	(6.6)%
Large commercial & industrial	36	50	(28.0)%	(11.9)%
Transportation	24,533	25,822	(5.0)%	(2.9)%
Total natural gas deliveries	82,182	89,896	(8.6)%	(1.8)%

(a) Reflects delivery volumes and revenue 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.

	As of December 31,	
Number of Gas Customers	2020	2019
Residential	492,298	487,337
Small commercial & industrial	44,472	44,374
Large commercial & industrial	5	2
Transportation	713	730
Total	537,488	532,443

Pricing for the year ended December 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. PECO's transmission formula rate filing was approved in the fourth quarter of 2019.

Other Revenue primarily includes revenue related to late payment charges. Other revenues for the year ended December 31, 2020 compared to the same period in 2019, decreased as PECO ceased new late fees for all customers and restored service to customers upon request who were disconnected in the last twelve months beginning March of 2020.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency, PGC, and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries as PECO remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, PECO acts as the billing agent and therefore does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from PECO, PECO is permitted to recover the electricity, natural gas, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power and fuel expense related to the electricity, natural gas, and RECs.

See Note 5—Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The decrease of $11 million for the year ended December 31, 2020 compared to the same period in 2019, respectively, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2020 vs. 2019 Increase (Decrease)
Storm-related costs[(a)]	$ 82
Labor, other benefits, contracting, and materials	23
Credit loss expense[(b)]	12
BSC costs	1
Pension and non-pension postretirement benefits expense	(4)
Other	7
	121
Regulatory Required Programs	(7)
Total increase	$ 114

(a) Reflects increased storm costs due to June and August 2020 storms.
(b) Increased credit loss expense primarily as a result of suspending customer disconnections, partially offset by the regulatory asset recorded in 2020 related to incremental credit loss expense due to COVID-19. See Note 3 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

	2020 vs. 2019 Increase (Decrease)
Depreciation and amortization[(a)]	$ 16
Regulatory asset amortization	(2)
Total increase	$ 14

(a) Depreciation and amortization expense increased primarily due to ongoing capital expenditures.

Interest expense, net increased $11 million for the year ended December 31, 2020 compared to the same period in 2019, respectively, primarily due to the issuance of debt in June 2020.

Effective income tax rates were (7.2)% and 11.0% for the years ended December 31, 2020 and 2019, respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information of the change in effective income tax rates.

Results of Operations—BGE

	2020	2019	(Unfavorable) Favorable Variance
Operating revenues	$ 3,098	$ 3,106	$ (8)
Operating expenses			
Purchased power and fuel expense	991	1,052	61
Operating and maintenance	789	760	(29)
Depreciation and amortization	550	502	(48)
Taxes other than income taxes	268	260	(8)
Total operating expenses	2,598	2,574	(24)
Operating income	500	532	(32)
Other income and (deductions)			
Interest expense, net	(133)	(121)	(12)
Other, net	23	28	(5)
Total other income and (deductions)	(110)	(93)	(17)
Income before income taxes	390	439	(49)
Income taxes	41	79	38
Net income	$ 349	$ 360	$ (11)

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. **Net income** remained relatively consistent primarily due to higher natural gas and electric distribution rates, partially offset by increased depreciation and amortization expense, increased interest expense, increased expense due to a commitment to a multi-year small business grants program, and a decrease in other revenues.

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

	2020 vs. 2019		
	Increase (Decrease)		
	Electric	Gas	Total
Distribution	$ 30	$ 54	$ 84
Transmission	(3)	—	(3)
Other	(14)	(9)	(23)
	13	45	58
Regulatory required programs	(55)	(11)	(66)
Total (decrease) increase	$ (42)	$ 34	$ (8)

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and customer usage. However, Operating revenues are not impacted by abnormal weather or usage per customer as a result of a bill stabilization adjustment (BSA) that provides for a fixed distribution charge per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

	As of December 31,	
Number of Electric Customers	**2020**	**2019**
Residential	1,190,678	1,177,333
Small commercial & industrial	114,173	114,504
Large commercial & industrial	12,478	12,322
Public authorities & electric railroads	267	268
Total	1,317,596	1,304,427

	As of December 31,	
Number of Gas Customers	**2020**	**2019**
Residential	647,188	639,426
Small commercial & industrial	38,267	38,345
Large commercial & industrial	6,101	6,037
Total	691,556	683,808

Distribution Revenue increased for the year ended December 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.

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 year ended December 31, 2020 compared to the same period in 2019, primarily due to the settlement agreement of transmission-related income tax regulatory liabilities, partially offset by higher fully recoverable costs. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other Revenue includes revenue related to late payment charges, mutual assistance, off-system sales, and service application fees. Other revenue decreased for the year ended December 31, 2020 compared to the same period in 2019, as BGE temporarily suspended customer disconnections for non-payment beginning March of 2020 and temporarily ceased new late fees for all customers and restored service to customers upon request who were disconnected in the last twelve months.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as conservation, demand response, STRIDE, and the POLR mechanism. The riders are designed to provide full and current cost recovery, as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries as BGE remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, BGE acts as the billing agent and therefore does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from BGE, BGE is permitted to recover the electricity and natural gas procurement costs from customers and therefore records the amounts related to the electricity and/or natural gas in Operating revenues and Purchased power and fuel expense. BGE recovers electricity and natural gas procurement costs from customers with a slight mark-up.

See Note 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

The decrease of $61 million for the year ended December 31, 2020 compared to the same period in 2019, respectively, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2020 vs. 2019
	Increase (Decrease)
Small business grants commitment[a]	$ 15
BSC costs	13
Credit loss expense[b]	7
Labor, other benefits, contracting, and materials	(1)
Pension and non-pension postretirement benefits expense	(2)
	32
Regulatory required programs	(3)
Total increase	$ 29

(a) Reflects increased charitable contributions as a result of a commitment in 2020 to a multi-year small business grants program.
(b) Increased credit loss expense primarily as a result of suspending customer disconnections, partially offset by the regulatory asset recorded in 2020 related to incremental credit loss expense due to COVID-19. See Note 3 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

	2020 vs. 2019
	Increase
Depreciation and amortization[a]	$ 35
Regulatory required programs	10
Regulatory asset amortization	3
Total increase	$ 48

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Taxes other than income increased for the year ended December 31, 2020 compared to the same period in 2019, primarily due to higher property taxes.

Interest expense, net increased for the year ended December 31, 2020 compared to the same period in 2019, primarily due to the issuance of debt in September 2019 and June 2020.

Effective income tax rates were 10.5% and 18.0% for the years ended December 31, 2020 and 2019, respectively. The change is primarily related to the settlement agreement of transmission-related income tax regulatory liabilities. See Note 3 — Regulatory Matters and Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—PHI

PHI's Results of Operations include the results of its three reportable segments, Pepco, DPL, and ACE. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services and the costs are directly charged or allocated to the applicable subsidiaries. Additionally, the results of PHI's corporate operations include interest costs from various financing activities. All material intercompany accounts and transactions have been eliminated in consolidation. The following table sets forth PHI's GAAP consolidated Net Income by Registrant for the year ended December 31, 2020 compared to the same period in 2019. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	2020	2019	Favorable (Unfavorable) Variance
PHI	$ 495	$ 477	$ 18
Pepco	266	243	23
DPL	125	147	(22)
ACE	112	99	13
Other[a]	(8)	(12)	4

(a) Primarily includes eliminating and consolidating adjustments, PHI's corporate operations, shared service entities, and other financing and investing activities.

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. **Net income** increased by $18 million primarily due to higher electric distribution rates, higher transmission rates (net of the impact of the settlement agreement of ongoing transmission-related income tax regulatory liabilities), and decreased expense resulting from an absence of an increase in environmental liabilities, and a gain on sale of land at Pepco in the fourth quarter of 2020, partially offset by an increase in depreciation and amortization expense, an increase in DPL storm costs related to the August 2020 storms in Delaware, an increase in credit loss expense primarily as a result of suspending customer disconnections partially offset by the regulatory asset recorded in 2020 related to incremental credit loss expense due to COVID-19, and unfavorable weather conditions in ACE and DPL Delaware's service territories.

Results of Operations—Pepco

	2020	2019	(Unfavorable) Favorable Variance
Operating revenues	$ 2,149	$ 2,260	$ (111)
Operating expenses			
Purchased power expense	602	665	63
Operating and maintenance	453	482	29
Depreciation and amortization	377	374	(3)
Taxes other than income taxes	367	378	11
Total operating expenses	1,799	1,899	100
Gain on sales of assets	9	—	9
Operating income	359	361	(2)
Other income and (deductions)			
Interest expense, net	(138)	(133)	(5)
Other, net	38	31	7
Total other income and (deductions)	(100)	(102)	2
Income before income taxes	259	259	—
Income taxes	(7)	16	23
Net income	$ 266	$ 243	$ 23

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. **Net income** increased by $23 million primarily due to decreased expense resulting from an absence of an increase in environmental liabilities, increased electric distribution revenues, and a gain on sale of land in the fourth quarter of 2020, partially offset by an increase in depreciation and amortization expense and an increase in credit loss expense primarily as a result of suspending customer disconnections partially offset by the regulatory asset recorded in 2020 related to incremental credit loss expense due to COVID-19.

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

	2020 vs. 2019
	Increase (Decrease)
Distribution	19
Transmission	(36)
Other	(3)
	(20)
Regulatory required programs	(91)
Total decrease	$ (111)

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.

	As of December 31,	
Number of Electric Customers	2020	2019
Residential	832,190	817,770
Small commercial & industrial	53,800	54,265
Large commercial & industrial	22,459	22,271
Public authorities & electric railroads	168	160
Total	908,617	894,466

Distribution Revenue increased for the year ended December 31, 2020 compared to the same period in 2019, primarily due to higher electric distribution rates in Maryland that became effective in August 2019 and customer growth in the District of Columbia.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, 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 year ended December 31, 2020 compared to the same period in 2019 primary due to the settlement agreement of transmission-related income tax regulatory liabilities. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other Revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes. Other revenue decreased for the year ended December 31, 2020 compared to the same period in 2019, as Pepco temporarily suspended customer disconnections for non-payment beginning March of 2020 and temporarily ceased new late fees for all customers and restored services to customers upon request who were disconnected in the last twelve months.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DC PLUG, and SOS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, as Pepco remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, Pepco acts as the billing agent and therefore does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from Pepco, Pepco is permitted to recover the electricity and REC procurement costs from customers and therefore records the amounts related to the electricity and RECs in Operating revenues and Purchased power expense. Pepco recovers electricity and REC procurement costs from customers with a slight mark-up.

See Note 5 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

The decrease of $63 million for the year ended December 31, 2020 compared to the same period in 2019, 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:

	2020 vs. 2019 (Decrease) Increase
Change in environmental liabilities	$ (22)
Expiration of lease arrangement	(15)
Pension and non-pension postretirement benefits expense	(6)
BSC and PHISCO costs	(4)
Storm related costs	(2)
Credit loss expense[(a)]	8
Labor, other benefits, contracting, and materials	15
Other	(1)
	(27)
Regulatory required programs	(2)
Total decrease	$ (29)

(a) Increased credit loss expense primarily as a result of suspending customer disconnections, partially offset by the regulatory asset recorded in 2020 related to incremental credit loss expense due to COVID-19. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

	2020 vs. 2019 Increase (Decrease)
Depreciation expense[(a)]	$ 18
Regulatory asset amortization	(2)
Regulatory required programs	(13)
Total increase	$ 3

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Taxes other than income decreased for the year ended December 31, 2020 compared to the same period in 2019, primarily due to lower taxes as part of regulatory required programs that are fully offset within Operating revenues.

Interest expense, net increased for the year ended December 31, 2020 compared to the same period in 2019, primarily due to issuance of debt in June 2019, February 2020, and June 2020.

Gain on sales of assets for the year ended December 31, 2020 compared to the year ended December 31, 2019 increased due the sale of land in the fourth quarter of 2020.

Effective income tax rates were (2.7)% and 6.2% for the years ended December 31, 2020 and 2019, respectively. The change is primarily related to the settlement agreement of ongoing transmission-related income tax regulatory liabilities. See Note 3 — Regulatory Matters and Note 14 — 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

	2020	2019	(Unfavorable) Favorable Variance
Operating revenues	$ 1,271	$ 1,306	$ (35)
Operating expenses			
Purchased power and fuel expense	503	526	23
Operating and maintenance	361	323	(38)
Depreciation and amortization	191	184	(7)
Taxes other than income taxes	65	56	(9)
Total operating expenses	1,120	1,089	(31)
Operating income	151	217	(66)
Other income and (deductions)			
Interest expense, net	(61)	(61)	—
Other, net	10	13	(3)
Total other income and (deductions)	(51)	(48)	(3)
Income before income taxes	100	169	(69)
Income taxes	(25)	22	47
Net income	$ 125	$ 147	$ (22)

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. **Net income** decreased by $22 million primarily due to an increase in storm costs related to the August 2020 storms in Delaware, an increase in credit loss expense primarily as a result of suspending customer disconnections partially offset by the regulatory asset recorded in 2020 related to incremental credit loss expense due to COVID-19, unfavorable weather conditions in DPL's Delaware electric service territory, and an increase in depreciation and amortization expense, partially offset by higher electric distribution rates and an increase in transmission rates (net of the impact of the settlement agreement of transmission-related income tax regulatory liabilities).

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

	2020 vs. 2019		
	(Decrease) Increase		
	Electric	Gas	Total
Weather	$ (9)	$ —	$ (9)
Volume	2	(5)	(3)
Distribution	12	4	16
Transmission	(18)	—	(18)
Other	2	(1)	1
	(11)	(2)	(13)
Regulatory required programs	(17)	(5)	(22)
Total decrease	$ (28)	$ (7)	$ (35)

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 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 year ended December 31, 2020 compared to the same period in 2019, Operating revenues related to weather decreased primarily due to 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 year ended December 31, 2020 compared to same period in 2019 and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Delaware Electric Service Territory	2020	2019	Normal	2020 vs. 2019	2020 vs. Normal
Heating Degree-Days	4,146	4,475	4,652	(7.4)%	(10.9)%
Cooling Degree-Days	1,264	1,476	1,239	(14.4)%	2.0 %

	For the Years Ended December 31,			% Change	
Delaware Natural Gas Service Territory	2020	2019	Normal	2020 vs. 2019	2020 vs. Normal
Heating Degree-Days	4,146	4,475	4,675	(7.4)%	(11.3)%

Volume, exclusive of the effects of weather, remained relatively consistent for the year ended December 31, 2020 compared to the same period in 2019.

Electric Retail Deliveries to Delaware Customers (in GWhs)	2020	2019	% Change 2020 vs. 2019	Weather - Normal % Change [(b)]
Residential	3,149	3,149	—%	4.8 %
Small commercial & industrial	1,255	1,320	(4.9)%	(2.6)%
Large commercial & industrial	3,225	3,424	(5.8)%	(4.8)%
Public authorities & electric railroads	32	34	(5.9)%	(5.9)%
Total electric retail deliveries[(a)]	7,661	7,927	(3.4)%	(0.7)%

	As of December 31,	
Number of Total Electric Customers (Maryland and Delaware)	2020	2019
Residential	472,621	468,162
Small commercial & industrial	62,461	61,721
Large commercial & industrial	1,223	1,411
Public authorities & electric railroads	609	613
Total	536,914	531,907

(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)	2020	2019	% Change 2020 vs. 2019	Weather - Normal % Change[(b)]
Residential	7,832	8,613	(9.1)%	(2.5) %
Small commercial & industrial	3,718	4,287	(13.3)%	(7.5) %
Large commercial & industrial	1,703	1,811	(6.0)%	(6.0) %
Transportation	6,631	6,733	(1.5)%	0.2 %
Total natural gas deliveries[(a)]	19,884	21,444	(7.3)%	(3.0) %

Number of Delaware Natural Gas Customers	As of December 31, 2020	2019
Residential	127,128	125,873
Small commercial & industrial	10,017	9,999
Large commercial & industrial	16	17
Transportation	161	159
Total	137,322	136,048

(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 year ended December 31, 2020 compared to the same period in 2019 primarily due to higher electric distribution rates in Maryland that became effective in July 2020, higher electric and natural gas distribution rates in Delaware that became effective in the second half of 2020, and the Distribution System Improvement Charge (DSIC) rate increases during 2020.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, and the highest daily peak load, which is updated annually in January based on the prior calendar years. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue decreased for the year ended December 31, 2020 compared to the same period in 2019 primarily due to the settlement agreement of transmission-related income tax regulatory liabilities, partially offset by higher fully recoverable costs. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other Revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DE Renewable Portfolio Standards, SOS procurement and administrative costs, and GCR costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries as DPL remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, DPL acts as the billing agent and therefore does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from DPL, DPL is permitted to recover the electricity, natural gas, and REC procurement costs from customers and therefore records the amounts related to the electricity, natural gas, and RECs in Operating revenues and Purchased power and fuel expense. DPL recovers electricity and REC procurement costs from customers with a slight mark-up and natural gas costs without mark-up.

See Note 5 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

The decrease of $23 million for the year ended December 31, 2020 compared to the same period in 2019, 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:

	2020 vs. 2019 Increase (Decrease)
Storm-related costs	$ 19
Labor, other benefits, contracting, and materials	14
Credit loss expense[(a)]	8
Pension and non-pension postretirement benefits expense	(4)
BSC and PHISCO costs	(1)
Other	(1)
	35
Regulatory required programs	3
Total increase	$ 38

(a) Increased credit loss expense primarily as a result of suspending customer disconnections, partially offset by the regulatory asset recorded in 2020 related to incremental credit loss expense due to COVID-19. See Note 3 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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

	2020 vs. 2019 Increase (Decrease)
Depreciation and amortization[(a)]	$ 10
Regulatory asset amortization	(1)
Regulatory required programs	(2)
Total increase	$ 7

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Taxes other than income taxes increased for the year ended December 31, 2020 compared to the same period in 2019 primarily due to higher property taxes for Maryland and Delaware.

Effective income tax rates were (25.0)% and 13.0% for the years ended December 31, 2020 and 2019, respectively. The decrease for the year ended December 31, 2020 is primarily related to the settlement agreement of transmission-related income tax regulatory liabilities. See Note 3 — Regulatory Matters and Note 14 — 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

	2020	2019	Favorable (Unfavorable) Variance
Operating revenues	$ 1,245	$ 1,240	$ 5
Operating expenses			
Purchased power expense	609	608	(1)
Operating and maintenance	326	320	(6)
Depreciation and amortization	180	157	(23)
Taxes other than income taxes	8	4	(4)
Total operating expenses	1,123	1,089	(34)
Gain on sale of assets	2	—	2
Operating income	124	151	(27)
Other income and (deductions)			
Interest expense, net	(59)	(58)	(1)
Other, net	6	6	—
Total other income and (deductions)	(53)	(52)	(1)
Income before income taxes	71	99	(28)
Income taxes	(41)	—	41
Net income	$ 112	$ 99	$ 13

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019. **Net income** increased $13 million primarily due to higher electric distribution rates and an increase in transmission rates (net of the impact of the settlement agreement of transmission-related income tax regulatory liabilities), partially offset by an increase in depreciation and amortization expense and unfavorable weather conditions in ACE's service territory.

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

	2020 vs. 2019 (Decrease) Increase
Weather	$ (8)
Volume	(1)
Distribution	24
Transmission	(19)
Other	3
	(1)
Regulatory required programs	6
Total increase	$ 5

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 year ended December 31, 2020 compared to the 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. The changes in heating and cooling degree days in ACE's service territory for the year ended December 31, 2020 compared to same period in 2019, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2020**	**2019**	**Normal**	**2020 vs. 2019**	**2020 vs. Normal**
Heating Degree-Days	4,029	4,467	4,667	(9.8)%	(13.7)%
Cooling Degree-Days	1,314	1,374	1,174	(4.4)%	11.9 %

Volume, exclusive of the effects of weather, remained relatively consistent for the year ended December 31, 2020 compared to the same period in 2019.

Electric Retail Deliveries to Customers (in GWhs)	**2020**	**2019**	**% Change 2020 vs. 2019**	**Weather - Normal % Change[b]**
Residential	4,029	3,966	1.6 %	4.7 %
Small commercial & industrial	1,277	1,346	(5.1)%	(4.0)%
Large commercial & industrial	3,067	3,429	(10.6)%	(10.0)%
Public authorities & electric railroads	47	47	—%	(0.2)%
Total retail deliveries[a]	8,420	8,788	(4.2)%	(2.5)%

	As of December 31,	
Number of Electric Customers	**2020**	**2019**
Residential	497,672	494,596
Small commercial & industrial	61,622	61,497
Large commercial & industrial	3,282	3,392
Public authorities & electric railroads	701	679
Total	563,277	560,164

(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 year ended December 31, 2020 compared to the same period in 2019 primarily due to higher electric distribution rates that became effective in April 2019 and April 2020.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue decreased for the year ended December 31, 2020 compared to the same period in 2019 primarily due to the settlement agreement for transmission-related income tax regulatory liabilities, partially offset by higher fully recoverable costs. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other Revenue includes rental revenue, service connection fees, and mutual assistance revenues.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, Societal Benefits Charge, Transition Bonds, and BGS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers.

Customer choice programs do not impact the volume of deliveries, as ACE remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, ACE acts as the billing agent and therefore does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from ACE, ACE is permitted to recover the electricity, ZEC, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power expense related to the electricity, ZECs, and RECs.

See Note 5 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

The increase of $1 million for the year ended December 31, 2020 compared to same period in 2019, 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:

	2020 vs. 2019 Increase (Decrease)
Labor, other benefits, contracting and materials	$ 6
Storm-related costs	3
Pension and non-pension postretirement benefits expense	(1)
Other	(2)
	6
Regulatory required programs[(a)]	—
Total increase	$ 6

(a) ACE is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through the Societal Benefits Charge.

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

	2020 vs. 2019 Increase (Decrease)
Depreciation and amortization[(a)]	$ 17
Regulatory asset amortization	(2)
Regulatory required programs	8
Total increase	$ 23

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.

Gain on sale of assets for year ended December 31, 2020 compared to same period in 2019 increased due to the sale of land in the first quarter of 2020.

Effective income tax rates were (57.7)% and 0.0% for the years ended December 31, 2020 and 2019, respectively. The change is primarily related to the settlement agreement of transmission-related income tax regulatory liabilities. See Note 3 — Regulatory Matters and Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

Liquidity and Capital Resources

All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations, the sale of certain receivables, as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each of the Registrants annually evaluates its financing plan, dividend practices, and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to credit facilities with aggregate bank commitments of $10.6 billion. 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 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on the sale of customer accounts receivable. 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 OPEB obligations, and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, the Utility Registrants operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' debt and credit agreements.

Despite disruptions in the financial markets due to COVID-19, the Registrants issued long-term debt of $5.3 billion and were able to successfully complete their planned long-term debt issuances in 2020.

NRC Minimum Funding Requirements (Exelon and Generation)

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are typically based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant's owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 10 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT funds could appreciate in value. A shortfall could require that Generation address the shortfall by, 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. Within two years after shutting down a plant, Generation must submit a PSDAR to the NRC that includes the planned option for decommissioning the site. Upon retirement, Dresden will have adequate funding assurance, however, due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value, Byron may no longer meet the NRC minimum funding requirements and, as a result, the NRC may require additional financial assurance including possibly a parental guarantee from Exelon. Considering the different approaches to decommissioning available to Generation, the most likely estimates currently anticipated could require financial assurance for radiological decommissioning at Byron of up to $90 million.

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, under the regulations, the NRC must approve an exemption in order for Generation to utilize the NDT funds to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs, if applicable). If a unit does not receive this exemption, those costs would be borne by Generation without reimbursement from or access to the NDT funds. Accordingly, based on current projections of the most likely decommissioning approach, it is expected that Dresden would not require supplemental cash from Generation, but some portion of the Byron spent fuel management costs would need to be funded through supplemental cash from Generation. While the ultimate amounts may vary and could be offset by reimbursement of certain spent fuel management costs under the DOE settlement agreement, decommissioning for Byron may require supplemental cash from Generation of up to $185 million, net of taxes, over a period of 10 years after permanent shutdown.

As of December 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 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on nonrecourse debt and credit facilities.

Cash Flows from Operating Activities (All Registrants)

Generation’s cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation’s future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

The Utility Registrants' cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE, and DPL, gas distribution services. The Utility Registrants' distribution services are provided to an established and diverse base of retail customers. The Utility Registrants' future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, and their ability to achieve operating cost reductions.

See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements 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 years ended December 31, 2020 and 2019 by Registrant:

(Decrease) increase in cash flows from operating activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income	$ (1,074)	$ (638)	$ (250)	$ (81)	$ (11)	$ 18	$ 23	$ (22)	$ 13
Adjustments to reconcile net income to cash:									
Non-cash operating activities	273	328	156	(42)	(33)	(120)	(123)	25	(3)
Pension and non-pension postretirement benefit contributions	(193)	(80)	(71)	10	(30)	(14)	3	1	(1)
Income taxes	204	(116)	(87)	65	127	(41)	(10)	(37)	(3)
Changes in working capital and other noncurrent assets and liabilities	(2,456)	(2,633)	(93)	74	79	42	96	11	(68)
Option premiums paid, net	(110)	(110)	—	—	—	—	—	—	—
Collateral received (posted), net	932	960	(34)	—	4	—	—	—	—
(Decrease) increase in cash flows from operating activities	$ (2,424)	$ (2,289)	$ (379)	$ 26	$ 136	$ (115)	$ (11)	$ (22)	$ (62)

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 2020 and 2019 were as follows:

- See Note 24 —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 14 —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.
- During 2020, Exelon and Generation derecognized approximately $1.2 billion of accounts receivable. See Note 6 — Accounts Receivable for additional information on the sales of customer **accounts receivable**.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation, and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy to make levelized annual contributions with the objective of achieving 100% funded status on an ABO basis over time. This level funding strategy helps minimize volatility of future period required pension contributions. Based on this funding strategy and current market conditions, which are subject to change, Exelon's estimated annual qualified pension contributions will be approximately $500 million in 2021. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

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

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

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Exelon	$ 505	$ 51	$ 75
Generation	196	27	24
ComEd	170	2	23
PECO	14	1	—
BGE	57	1	16
PHI	29	9	7
Pepco	1	2	6
DPL	—	1	—
ACE	3	—	—

To the extent interest rates decline significantly or the pension and OPEB plans earn less than the expected asset returns, annual pension contribution requirements in future years could increase. Conversely, to the extent interest rates increase significantly or the pension and OPEB plans earn greater than the expected asset returns, annual pension and OPEB contribution requirements in future years could decrease. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

Cash Flows from Investing Activities (All Registrants)

The following table provides a summary of the change in cash flows from investing activities for the years ended December 31, 2020 and 2019 by Registrant:

Increase (decrease) in cash flows from investing activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	$ (800)	$ 98	$ (302)	$ (208)	$ (102)	$ (249)	$ (147)	$ (76)	$ (26)
Proceeds from NDT fund sales, net	(87)	(87)	—	—	—	—	—	—	—
Acquisitions of assets and businesses, net	41	41	—	—	—	—	—	—	—
Proceeds from sales of assets and businesses	(7)	(6)	—	—	—	—	—	—	—
Changes in intercompany money pool	—	—	—	136	—	—	—	—	—
Collection of DPP	3,771	3,771	—	—	—	—	—	—	—
Other investing activities	6	8	(27)	8	(6)	10	(3)	(4)	7
Increase (decrease) in cash flows from investing activities	$ 2,924	$ 3,825	$ (329)	$ (64)	$ (108)	$ (239)	$ (150)	$ (80)	$ (19)

Significant investing cash flow impacts for the Registrants for 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

The Registrants most recent estimates of capital expenditures for plant additions and improvements for 2021 are approximately as follows:

(in millions)	Transmission	Distribution	Gas	Total
Exelon	N/A	N/A	N/A	$ 7,775
Generation	N/A	N/A	N/A	1,150
ComEd	475	1,925	N/A	2,400
PECO	175	750	350	1,275
BGE	325	450	425	1,200
PHI	525	1,100	75	1,700
Pepco	250	675	N/A	925
DPL	125	225	75	425
ACE	150	200	N/A	350

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 48% of projected 2021 capital expenditures at Generation are for the acquisition of nuclear fuel, with the remaining amounts primarily reflecting additions and upgrades to existing generation facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that it will fund capital expenditures with internally generated funds and borrowings.

Utility Registrants

Projected 2021 capital expenditures at the Utility Registrants are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as the Utility Registrants' construction commitments under PJM's RTEP.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In 2010, NERC provided guidance to transmission owners that recommended the Utility Registrants perform assessments of their transmission lines. ComEd, PECO, and BGE submitted their final bi-annual reports to NERC in January 2014. PECO will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. PECO's forecasted 2021 capital expenditures above reflect capital spending for remediation to be completed through 2021. ComEd, BGE, Pepco, DPL, and ACE are complete with their assessments and do not expect capital expenditures related to this guidance in 2021.

The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent.

Cash Flows from Financing Activities (All Registrants)

The following tables provides a summary of the change in cash flows from financing activities for the years ended December 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	$ 5	$ 200	$ 63	$ —	$ (116)	$ 131	$ (89)	$ 34	$ 186
Long-term debt, net	403	(958)	100	25	—	146	162	35	(53)
Changes in intercompany money pool	—	385	—	40	—	(3)	—	—	—
Dividends paid on common stock	(84)	—	9	18	(22)	—	(19)	(2)	10
Distributions to member	—	(835)	—	—	—	(27)	—	—	—
Contributions from parent/member	—	23	462	60	218	96	102	49	(58)
Other financing activities	(121)	(19)	3	2	—	(5)	(3)	(1)	—
Increase (decrease) in cash flows from financing activities	$ 203	$ (1,204)	$ 637	$ 145	$ 80	$ 338	$ 153	$ 115	$ 85

Significant financing cash flow impacts for the Registrants for 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 Note 17 - Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on short-term borrowings.
- **Long-term debt, net,** varies due to debt issuances and redemptions each year. Refer to debt issuances and redemptions tables below for additional information.
- **Changes in intercompany money pool** are driven by short-term borrowing needs. Refer to more information regarding the intercompany money pool below.
- Exelon's ability to pay **dividends** on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. See Note 19 - Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on dividend restrictions. See below for quarterly dividends declared.
- For the years ended December 31, 2020 and 2019, other financing activities primarily consists of debt issuance costs. See debt issuances table below for additional information on the Registrants' debt issuances.

Debt Issuances and Redemptions

See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' long-term debt. Debt activity for 2020 and 2019 by Registrant was as follows:

During 2020, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Notes	4.05 %	April 15, 2030	$ 1,250	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes	4.70 %	April 15, 2050	750	Repay existing indebtedness and for general corporate purposes.
Generation	Senior Notes	3.25 %	June 1, 2025	900	Repay existing indebtedness and for general corporate purposes.
Generation	EGR IV Nonrecourse Debt(a)	LIBOR + 2.75%	December 15, 2027	750	Repay existing indebtedness and for general corporate purposes.
Generation	Energy Efficiency Project Financing(b)	3.95 %	February 28, 2021	3	Funding to install energy conservation measures for the Fort Meade project.
Generation	Energy Efficiency Project Financing(b)	2.53 %	March 31, 2021	3	Funding to install energy conservation measures for the Fort AP Hill project.
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.
ComEd	First Mortgage Bonds, Series 129	3.00 %	March 1, 2050	650	Repay a portion of outstanding commercial paper obligations and fund other general corporate purposes.
PECO	First and Refunding Mortgage Bonds	2.80 %	June 15, 2050	350	Funding for general corporate purposes.
BGE	Senior Notes	2.90 %	June 15, 2050	400	Repay commercial paper obligations and for general corporate purposes.
Pepco	First Mortgage Bonds	2.53 %	February 25, 2030	150	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	3.28 %	September 23, 2050	150	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	2.53 %	June 9, 2030	100	Repay existing indebtedness and for general corporate purposes.
DPL	Tax-Exempt Bonds(c)	1.05 %	January 1, 2031	78	Refinance existing indebtedness.
ACE	Tax-Exempt First Mortgage Bonds	2.25 %	June 1, 2029	23	Refinance existing indebtedness.
ACE	First Mortgage Bonds	3.24 %	June 9, 2050	100	Repay existing indebtedness and for general corporate purposes.

(a) See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of nonrecourse debt.
(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.
(c) The bonds have a 1.05% interest rate through July 2025.

During 2019, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing[(a)]	3.95 %	February 28, 2021	$ 4	Funding to install energy conservation measures for the Fort Meade project.
Generation	Energy Efficiency Project Financing[(a)]	3.46 %	February 28, 2021	39	Funding to install energy conservation measures for the Marine Corps. Logistics Project.
Generation	Energy Efficiency Project Financing[(a)]	2.53 %	March 31, 2021	2	Funding to install energy conservation measures for the Fort AP Hill project.
ComEd	First Mortgage Bonds, Series 126	4.00 %	March 1, 2049	400	Repay a portion of ComEd's outstanding commercial paper obligations and fund other general corporate purposes.
ComEd	First Mortgage Bonds, Series 127	3.20 %	November 15, 2049	300	Repay a portion of ComEd's outstanding commercial paper obligations and fund other general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.00 %	September 15, 2049	325	Repay short-term borrowings and for general corporate purposes.
BGE	Senior Notes	3.20 %	September 15, 2049	400	Repay commercial paper obligations and for general corporate purposes.
Pepco	First Mortgage Bonds	3.45 %	June 13, 2029	150	Repay existing indebtedness and for general corporate purposes.
Pepco	Unsecured Tax-Exempt Bonds	1.70 %	September 1, 2022	110	Refinance existing indebtedness.
DPL	First Mortgage Bonds	4.14 %	December 12, 2049	75	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	3.50 %	May 21, 2029	100	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	4.14 %	May 21, 2049	50	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.

During 2020, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon	Notes	2.85%	June 15, 2020	$ 900
Exelon	Long-Term Software License Agreement	3.95%	May 1, 2024	24
Generation	Senior Notes	2.95%	January 15, 2020	1,000
Generation	Senior Notes	4.00%	October 1, 2020	550
Generation	Senior Notes(a)	5.15%	December 1, 2020	550
Generation	Tax-Exempt Bonds	2.50% - 2.70%	December 1, 2025 - June 1, 2036	412
Generation	EGR IV Nonrecourse Debt(b)	3 month LIBOR + 3.00%	November 30, 2024	796
Generation	Continental Wind Nonrecourse Debt(b)	6.00%	February 28, 2033	33
Generation	Antelope Valley DOE Nonrecourse Debt(b)	2.29% - 3.56%	January 5, 2037	23
Generation	RPG Nonrecourse Debt(b)	4.11%	March 31, 2035	9
Generation	Energy Efficiency Project Financing	3.71%	December 31, 2020	4
Generation	NUKEM	3.15%	September 30, 2020	3
Generation	SolGen Nonrecourse Debt	3.93%	September 30, 2036	3
Generation	Energy Efficiency Project Financing	4.12%	November 30, 2020	1
ComEd	First Mortgage Bonds	4.00%	August 1, 2020	500
DPL	Tax-Exempt Bonds	5.40%	February 1, 2031	78
ACE	Tax-Exempt First Mortgage Bonds	4.88%	June 1, 2029	23
ACE	Transition Bonds	5.55%	October 20, 2023	20

(a) The senior notes are legacy Constellation mirror debt that were previously held at Exelon and Generation. As part of the 2012 Constellation merger, Exelon and Generation assumed intercompany loan agreements that mirrored the terms and amounts of external obligations held by Exelon, resulting in intercompany notes payable at Generation.

(b) See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of nonrecourse debt.

During 2019, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon	Long-Term Software License Agreement	3.95%	May 1, 2024	$ 18
Generation	Antelope Valley DOE Nonrecourse Debt(a)	2.33% - 3.56%	January 5, 2037	23
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	5
Generation	Continental Wind Nonrecourse Debt(a)	6.00%	February 28, 2033	32
Generation	Pollution control notes	2.50%	March 1, 2019	23
Generation	RPG Nonrecourse Debt(a)	4.11%	March 31, 2035	10
Generation	Energy Efficiency Project Financing	3.46%	April 30, 2019	39
Generation	EGR IV Nonrecourse Debt(a)	3 month LIBOR + 3.00%	November 30, 2024	38
Generation	Hannie Mae, LLC Defense Financing	4.12%	November 30, 2019	1
Generation	Energy Efficiency Project Financing	3.72%	July 31, 2019	25
Generation	NUKEM	3.15%	September 30, 2020	36
Generation	SolGen Nonrecourse Debt(a)	3.93%	September 30, 2036	6
Generation	Energy Efficiency Project Financing	4.17%	October 31, 2019	1
Generation	Energy Efficiency Project Financing	3.53%	March 31, 2020	1
Generation	Energy Efficiency Project Financing	4.26%	September 30, 2019	1
Generation	Senior Notes	5.20%	October 1, 2019	600
Generation	Dominion Federal Corp	3.17%	October 31, 2019	18
Generation	Fort Detrick Project Financing	3.55%	October 31, 2019	1
ComEd	First Mortgage Bonds	2.15%	January 15, 2019	300
Pepco	Secured Tax-Exempt Bonds	6.20% - 7.49%	2021 - 2022	110
DPL	Medium Term Notes, Unsecured	7.61%	December 2, 2019	12
ACE	Transition Bonds	5.55%	October 20, 2023	18

(a) See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of nonrecourse debt.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends

Quarterly dividends declared by the Exelon Board of Directors during the year ended December 31, 2020 and for the first quarter of 2021 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
Third Quarter 2020	July 28, 2020	August 14, 2020	September 10, 2020	$ 0.3825
Fourth Quarter 2020	November 2, 2020	November 16, 2020	December 10, 2020	$ 0.3825
First Quarter 2021	February 21, 2021	March 8, 2021	March 15, 2021	$ 0.3825

(a) Exelon's Board of Directors approved an updated dividend policy for 2021. The 2021 quarterly dividend will remain the same as the 2020 dividend of $0.3825 per share.

Credit Matters (All Registrants)

The Registrants fund liquidity needs for capital investment, working capital, energy hedging, and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets, and large, diversified credit facilities. The credit facilities include $10.6 billion in aggregate total commitments of which $7.7 billion was available to support additional commercial paper as of December 31, 2020, and of which no financial institution has more than 7% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper markets and had availability under their revolving credit facilities during 2020 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising, and merger activity. See PART I. ITEM 1A. RISK FACTORS 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 December 31, 2020, it would have been required to provide incremental collateral of approximately $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 $4.7 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 December 31, 2020 and available credit facility capacity prior to any incremental collateral at December 31, 2020:

	PJM Credit Policy Collateral	Other Incremental Collateral Required[(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 13	$ —	$ 675
PECO	2	34	600
BGE	10	54	600
Pepco	8	—	264
DPL	4	9	154
ACE	—	—	113

(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 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants’ credit facilities and short term borrowing activity.

Capital Structure

At December 31, 2020, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Long-term debt	50 %	27 %	43 %	44 %	47 %	40 %	49 %	48 %	47 %
Long-term debt to affiliates[(a)]	1 %	1 %	1 %	2 %	— %	— %	— %	— %	— %
Common equity	46 %	— %	54 %	54 %	53 %	— %	50 %	48 %	47 %
Member's equity	— %	68 %	— %	— %	— %	58 %	— %	— %	— %
Commercial paper and notes payable	3 %	4 %	2 %	— %	— %	2 %	1 %	4 %	6 %

(a) Includes approximately $390 million, $205 million, and $184 million owed to unconsolidated affiliates of Exelon, ComEd, and PECO respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd and PECO. See Note 23 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

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 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

The credit ratings for Exelon Corporate, PECO, BGE, PHI, Pepco, DPL, and ACE did not change for the twelve months ended December 31, 2020. On November 4, 2020, S&P revised its assessment of the strategic relationship between Exelon and Generation and subsequently lowered Generation's senior unsecured debt rating to 'BBB' from 'BBB+'. On July 21, 2020, S&P lowered ComEd's long-term issuer credit rating from 'A-' to a 'BBB+'. S&P also affirmed the current 'A' rating on ComEd's senior secured debt and 'A-2' short-term rating, which influences long and short-term borrowing cost.

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 December 31, 2020, are presented in the following tables:

	For the Year Ended December 31, 2020		As of December 31, 2020
Exelon Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Exelon Corporate	$ 1,364	$ —	$ 598
Generation	254	(980)	(285)
PECO	292	(40)	(40)
BSC	25	(563)	(312)
PHI Corporate	—	(22)	(21)
PCI	60	—	60

	For the Year Ended December 31, 2020		As of December 31, 2020
PHI Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Pepco	$ 166	$ (57)	$ —
DPL	62	(95)	—
ACE	—	(133)	—

Shelf Registration Statements

Exelon, Generation, and the Utility Registrants have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2022. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations

The Utility Registrants are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	As of December 31, 2020					
	Short-term Financing Authority(a)			Long-term Financing Authority(a)		
	Commission	**Expiration Date**	**Amount**	**Commission**	**Expiration Date**	**Amount**
ComEd(b)	FERC	December 31, 2021	$ 2,500	ICC	February 1, 2023	$ 893
PECO	FERC	December 31, 2021	1,500	PAPUC	December 31, 2021	1,225
BGE	FERC	December 31, 2021	700	MDPSC	N/A	1,100
Pepco	FERC	December 31, 2021	500	MDPSC / DCPSC	December 31, 2022	900
DPL	FERC	December 31, 2021	500	MDPSC / DPSC	December 31, 2022	297
ACE(c)	NJBPU	December 31, 2021	350	NJBPU	December 31, 2022	600

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

(b) As of December 31, 2020, ComEd had $893 million in new money long-term debt financing authority from the ICC with an expiration date of February 1, 2023. On January 20, 2021, ComEd received $350 million of long-term debt refinancing authority from the ICC approved with an effective date of February 1, 2021 and an expiration date of February 1, 2024.

(c) On December 2, 2020, ACE received approval from the NJBPU for $600 million in new long-term debt financing authority with an effective date of January 1, 2021.

Contractual Obligations and Off-Balance Sheet Arrangements

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2020 under existing contractual obligations, including payments due by period.

Exelon

		Payment due within			
	Total	2021	2022 - 2023	2024 - 2025	2026 and beyond
Long-term debt[a]	$ 36,839	$ 1,809	$ 3,933	$ 3,012	$ 28,085
Interest payments on long-term debt[b]	24,486	1,468	2,766	2,592	17,660
Operating leases[c]	1,213	141	224	193	655
Purchase power obligations[d]	1,613	512	823	264	14
Fuel purchase agreements[e]	5,667	1,183	1,584	1,237	1,663
Electric supply procurement	3,170	1,909	1,253	8	—
Long-term renewable energy and REC commitments	2,238	301	548	437	952
Other purchase obligations[f]	9,374	6,673	1,492	440	769
DC PLUG obligation	100	30	60	10	—
SNF obligation	1,208	—	—	—	1,208
Pension contributions[g]	3,030	505	1,010	1,010	505
Total contractual obligations	$ 88,938	$ 14,531	$ 13,693	$ 9,203	$ 51,511

(a) Includes amounts from ComEd and PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2020. Includes estimated interest payments due to ComEd and PECO financing trusts.
(c) Capacity payments associated with contracted generation lease agreements are net of sublease and capacity offsets of $98 million, $55 million, $44 million, $44 million, $44 million, and $179 million for 2021, 2022, 2023, 2024, 2025, and thereafter, respectively and $464 million in total.
(d) Purchase power obligations primarily include expected payments for REC purchases and payments associated with contracted generation agreements, which may be reduced based on plant availability. Expected payments exclude payments on renewable generation contracts that are contingent in nature.
(e) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity, and services, including those related to CENG.
(f) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(g) These amounts represent Exelon's expected contributions to its qualified pension plans. Qualified pension contributions for years after 2026 are not included.

Generation

		Payment due within			
	Total	2021	2022 - 2023	2024 - 2025	2026 and beyond
Long-term debt	$ 6,066	$ 195	$ 1,024	$ 900	$ 3,947
Interest payments on long-term debt[(a)]	3,536	270	474	443	2,349
Operating leases[(b)]	731	47	114	109	461
Purchase power obligations[(c)]	1,613	512	823	264	14
Fuel purchase agreements[(d)]	4,450	928	1,207	1,022	1,293
Other purchase obligations[(e)]	2,286	1,208	231	155	692
SNF obligation	1,208	—	—	—	1,208
Total contractual obligations	$ 19,890	$ 3,160	$ 3,873	$ 2,893	$ 9,964

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2020.

(b) Capacity payments associated with contracted generation lease agreements are net of sublease and capacity offsets of $98 million, $55 million, $44 million, $44 million, $44 million, and $179 million for 2021, 2022, 2023, 2024, 2025, and thereafter, respectively and $464 million in total.

(c) Purchase power obligations primarily include expected payments for REC purchases and capacity payments associated with contracted generation agreements, which may be reduced based on plant availability. Expected payments exclude payments on renewable generation contracts that are contingent in nature.

(d) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity, and services, including those related to CENG.

(e) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between Generation and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

ComEd

	Total	Payment due within 2021	2022 - 2023	2024 - 2025	2026 and beyond
Long-term debt[(a)]	$ 9,284	$ 350	$ —	$ 250	$ 8,684
Interest payments on long-term debt[(b)]	7,207	360	720	711	5,416
Operating leases	8	3	3	2	—
Electric supply procurement	600	388	212	—	—
Long-term renewable energy and REC commitments	1,953	269	485	384	815
Other purchase obligations[(c)]	1,524	1,397	74	35	18
ZEC commitments	1,127	176	351	351	249
Total contractual obligations	$ 21,703	$ 2,943	$ 1,845	$ 1,733	$ 15,182

(a) Includes amounts from ComEd financing trust.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Includes estimated interest payments due to the ComEd financing trust.

(c) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between ComEd and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

PECO

	Total	Payment due within 2021	2022 - 2023	2024 - 2025	2026 and beyond
Long-term debt[(a)]	$ 3,984	$ 300	$ 400	$ 350	$ 2,934
Interest payments on long-term debt[(b)]	2,867	146	280	271	2,170
Operating leases	1	1	—	—	—
Fuel purchase agreements[(c)]	405	138	183	41	43
Electric supply procurement	536	431	105	—	—
Other purchase obligations[(d)]	898	813	66	19	—
Total contractual obligations	$ 8,691	$ 1,829	$ 1,034	$ 681	$ 5,147

(a) Includes amounts from PECO financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Includes estimated interest payments due to the PECO financing trusts.

(c) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.

(d) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between PECO and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

BGE

	Total	Payment due within 2021	2022 - 2023	2024 - 2025	2026 and beyond
Long-term debt	$ 3,700	$ 300	$ 550	$ —	$ 2,850
Interest payments on long-term debt[a]	2,450	127	240	220	1,863
Operating leases	81	46	17	—	18
Fuel purchase agreements[b]	517	84	128	109	196
Electric supply procurement	1,088	665	423	—	—
Other purchase obligations[c]	1,372	976	364	26	6
Total contractual obligations	$ 9,208	$ 2,198	$ 1,722	$ 355	$ 4,933

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.

(b) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.

(c) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between BGE and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

PHI

	Total	Payment due within 2021	2022 - 2023	2024 - 2025	2026 and beyond
Long-term debt	$ 6,443	$ 339	$ 809	$ 700	$ 4,595
Interest payments on long-term debt[a]	4,135	266	517	447	2,905
Finance leases	53	8	16	16	13
Operating leases	306	40	77	69	120
Fuel purchase agreements[b]	295	33	66	65	131
Electric supply procurement	1,791	1,051	732	8	—
Long-term renewable energy and REC commitments	285	32	63	53	137
Other purchase obligations[c]	1,767	1,362	341	48	16
DC PLUG obligation	100	30	60	10	—
Total contractual obligations	$ 15,175	$ 3,161	$ 2,681	$ 1,416	$ 7,917

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2020.

(b) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.

(c) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between Pepco, DPL, ACE, and PHISCO and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

Pepco

	Total	Payment due within 2021	2022 - 2023	2024 - 2025	2026 and beyond
Long-term debt	$ 3,185	$ —	$ 309	$ 400	$ 2,476
Interest payments on long-term debt[a]	2,429	147	281	251	1,750
Finance leases	18	3	6	6	3
Operating leases	63	8	15	12	28
Electric supply procurement	754	432	314	8	—
Other purchase obligations[b]	1,034	748	243	32	11
DC PLUG obligation	100	30	60	10	—
Total contractual obligations	$ 7,583	$ 1,368	$ 1,228	$ 719	$ 4,268

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.

(b) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between Pepco and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

DPL

	Total	Payment due within 2021	2022 - 2023	2024 - 2025	2026 and beyond
Long-term debt	$ 1,666	$ 79	$ 500	$ —	$ 1,087
Interest payments on long-term debt[a]	1,016	59	116	82	759
Finance leases	21	3	6	6	6
Operating leases	80	11	19	15	35
Fuel purchase agreements[b]	295	33	66	65	131
Electric supply procurement	469	290	179	—	—
Long-term renewable energy and associated REC commitments	285	32	63	53	137
Other purchase obligations[c]	419	349	63	7	—
Total contractual obligations	$ 4,251	$ 856	$ 1,012	$ 228	$ 2,155

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2020.

(b) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.

(c) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between DPL and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

ACE

	Total	Payment due within 2021	2022 - 2023	2024 - 2025	2026 and beyond
Long-term debt	$ 1,407	$ 259	$ —	$ 300	$ 848
Interest payments on long-term debt [(a)]	527	46	92	86	303
Finance leases	14	2	4	4	4
Operating leases	16	5	7	4	—
Electric supply procurement	568	329	239	—	—
Other purchase obligations[(b)]	267	236	25	6	—
Total contractual obligations	$ 2,799	$ 877	$ 367	$ 400	$ 1,155

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2020 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.

(b) Represents the future estimated value at December 31, 2020 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between ACE and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

See Note 19 — Commitments and Contingencies and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' other commitments potentially triggered by future events. Additionally, see below for where to find additional information regarding certain contractual obligations in the Combined Notes to the Consolidated Financial Statements:

Item	Location within Notes to the Consolidated Financial Statements
Long-term debt	Note 17 — Debt and Credit Agreements
Interest payments on long-term debt	Note 17 — Debt and Credit Agreements
Finance leases	Note 11 — Leases
Operating leases	Note 11 — Leases
SNF obligation	Note 19 — Commitments and Contingencies
REC commitments	Note 3 — Regulatory Matters
ZEC commitments	Note 3 — Regulatory Matters
DC PLUG obligation	Note 3 — Regulatory Matters
Pension contributions	Note 15 — Retirement Benefits

Sales of Customer Accounts Receivable

On April 8, 2020, Generation entered into an accounts receivable financing facility with a number of financial institutions and a commercial paper conduit to sell certain receivables, which expires on April 7, 2021 unless renewed by the mutual consent of the parties in accordance with its terms. The facility allows Generation to obtain financing at lower cost and diversify its sources of liquidity. See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

ITEM 7A. 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.

Commodity Price Risk (All Registrants)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the total amount of energy Exelon generates and purchases differs from the amount of energy it has contracted to sell, Exelon is exposed to market fluctuations in commodity prices. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Electricity available from Generation’s owned or contracted generation supply in excess of Generation’s obligations to customers, including portions of the Utility Registrants' retail load, is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards, and options, with approved counterparties to hedge anticipated exposures. Generation uses derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2021 through 2023.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation’s owned and contracted generation positions which have not been hedged. Exelon's hedging program involves the hedging of commodity price risk for Exelon's expected generation, typically on a ratable basis over three-year periods. As of December 31, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% for 2021. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generation based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation’s sales to ComEd, PECO, BGE, Pepco, DPL, and ACE to serve their retail load.

A portion of Generation’s hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. 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 December 31, 2020 market conditions and hedged position would be a decrease in pre-tax net income of approximately $15 million for 2021. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation actively manages its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation’s portfolio. See Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

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. Supply market conditions may make Generation’s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation’s uranium concentrate requirements from 2021 through 2025 are supplied by three suppliers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon’s and Generation’s financial statements.

Utility Registrants

ComEd entered into 20-year floating-to-fixed renewable energy swap contracts beginning in June 2012, which are considered an economic hedge and have changes in fair value recorded to an offsetting regulatory asset or liability. ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which are considered derivatives and qualify for NPNS, and as a result are accounted for on an accrual basis of accounting. PECO, BGE, Pepco, DPL, and ACE have contracts to procure electric supply that are executed through a competitive procurement process. BGE, Pepco, DPL, and ACE have certain full requirements contracts, which are considered derivatives and qualify for NPNS, and as a result are accounted for on an accrual basis of accounting. Other full requirements contracts are not derivatives.

PECO, BGE, and DPL also have executed derivative natural gas contracts, which either qualify for NPNS or have no mark-to-market balances because the derivatives are index priced, to hedge their long-term price risk in the natural gas market. The hedging programs for natural gas procurement have no direct impact on their financial statements. PECO, BGE, Pepco, DPL, and ACE do not execute derivatives for speculative or proprietary trading purposes.

For additional information on these contracts, see Note 3 — Regulatory Matters and Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

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, 2018 to December 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 16 — 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 December 31, 2020 and 2019.

	Exelon	Generation	ComEd
Total mark-to-market energy contract net assets (liabilities) at December 31, 2018[a]	$ 299	$ 548	$ (249)
Total change in fair value during 2019 of contracts recorded in result of operations	(427)	(427)	—
Reclassification to realized at settlement of contracts recorded in results of operations	226	226	—
Changes in fair value—recorded through regulatory assets[b]	(52)	—	(52)
Changes in allocated collateral	572	572	—
Net option premium received	29	29	—
Option premium amortization	(22)	(22)	—
Upfront payments and amortizations[c]	(58)	(58)	—
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 result of operations	(203)	(203)	—
Reclassification to realized at settlement of contracts recorded in results of operations	469	469	—
Changes in allocated collateral	(513)	(513)	—
Net option premium paid	139	139	—
Option premium amortization	(104)	(104)	—
Upfront payments and amortizations[c]	73	73	—
Total mark-to-market energy contract net assets (liabilities) at December 31, 2020[a]	$ 428	$ 729	$ (301)

(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 December 31, 2019 and 2020, ComEd recorded a regulatory liability of $301 million and $301 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. ComEd recorded $78 million of decreases in fair value and an increase for realized losses due to settlements of $26 million in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2019. ComEd recorded $33 million of decrease in fair value and an increase for realized losses due to settlements of $33 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2020.

(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 18 — 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						
	2021	2022	2023	2024	2025	2026 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ (48)	$ 8	$ 8	$ 11	$ 17	$ —	$ (4)
Prices provided by external sources (Level 2)	212	78	13	(1)	1	—	303
Prices based on model or other valuation methods (Level 3)[c]	182	80	47	(7)	(16)	(157)	129
Total	$ 346	$ 166	$ 68	$ 3	$ 2	$ (157)	$ 428

(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 $416 million at December 31, 2020.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2021	2022	2023	2024	2025	2026 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ (48)	$ 8	$ 8	$ 11	$ 17	$ —	$ (4)
Prices provided by external sources (Level 2)	212	78	13	(1)	1	—	303
Prices based on model or other valuation methods (Level 3)	215	109	75	20	10	1	430
Total	$ 379	$ 195	$ 96	$ 30	$ 28	$ 1	$ 729

(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 $416 million at December 31, 2020.

ComEd

	Maturities Within						
	2021	2022	2023	2024	2025	2026 and Beyond	Total Fair Value
Commodity derivative contracts[a]:							
Prices based on model or other valuation methods (Level 3)[a]	$ (33)	$ (29)	$ (28)	$ (27)	$ (26)	$ (158)	$ (301)

(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 16—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a 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 December 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 table 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 December 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	$ 577	$ 27	$ 550	—	$ —
Non-investment grade	32	—	32	—	—
No external ratings					
Internally rated—investment grade	165	1	164	—	—
Internally rated—non-investment grade	80	28	52	—	—
Total	$ 854	$ 56	$ 798	—	$ —

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2020	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 520	$ 36	$ 21	$ 577
Non-investment grade	32	—	—	32
No external ratings				
Internally rated—investment grade	128	25	12	165
Internally rated—non-investment grade	67	10	3	80
Total	$ 747	$ 71	$ 36	$ 854

Net Credit Exposure by Type of Counterparty	As of December 31, 2020
Financial institutions	$ 15
Investor-owned utilities, marketers, power producers	607
Energy cooperatives and municipalities	138
Other	38
Total	$ 798

(a) As of December 31, 2020, credit collateral held from counterparties where Generation had credit exposure included $31 million of cash and $25 million of letters of credit.

The Utility Registrants

Credit risk for the Utility Registrants is governed by credit and collection policies, which are aligned with state regulatory requirements. The Utility Registrants are currently obligated to provide service to all electric customers within their franchised territories. The Utility Registrants record an allowance for credit losses on customer receivables, based upon historical loss experience, current conditions, and forward-looking risk factors, to provide for the potential loss from nonpayment by these customers. The Utility Registrants will monitor nonpayment from customers and will make any necessary adjustments to the allowance for credit losses on customer receivables. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for credit losses policy. The Utility Registrants did not have any customers representing over 10% of their revenues as of December 31, 2020. See Note 3 — Regulatory Matters of the

Combined Notes to Consolidated Financial Statements for additional information regarding the regulatory recovery of credit losses on customer accounts receivable.

As of December 31, 2020, the Utility Registrants net credit exposure to suppliers was immaterial. See Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

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 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements and Note 19 — 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 ITEM 7. Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities for additional information.

The Utility Registrants

As of December 31, 2020, the Utility Registrants were not required to post collateral under their energy and/or natural gas procurement contracts. See Note 3 — Regulatory Matters and Note 16 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (All Registrants)

All Registrants participate in all, or some, of the established, wholesale spot energy markets that are administered by PJM, ISO-NE, NYISO, CAISO, MISO, SPP, AESO, OIESO, and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there is no spot energy market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' financial statements.

Exchange Traded Transactions (Exelon, Generation, PHI, and DPL)

Generation enters into commodity transactions on NYMEX, ICE, NASDAQ, NGX, and the Nodal exchange ("the Exchanges"). DPL enters into commodity transactions on ICE. The Exchange clearinghouses act as the counterparty to each trade. Transactions on the Exchanges must adhere to comprehensive collateral and margining requirements. As a result, transactions on Exchanges are significantly collateralized and have limited counterparty credit risk.

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 $2 million decrease in Exelon pre-tax income for the year ended December 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 16—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 December 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 25 basis points increase in interest rates and 10% decrease in equity prices would result in a $851 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. See Liquidity and Capital Resources section of ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information of equity price risk as a result of the current capital and credit market conditions.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Generation

General

Generation's integrated business consists of the generation, physical delivery, and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services. Generation has five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions. These segments are discussed in further detail in ITEM 1. BUSINESS — Exelon Generation Company, LLC of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Exelon Corporation — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

A discussion of Generation's results of operations for 2020 compared to 2019 is set forth under Results of Operations—Generation in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool, or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has credit facilities in the aggregate of $5.3 billion that currently support its commercial paper program and issuances of letters of credit.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund Generation's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. Generation spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation’s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation’s contractual obligations, commercial commitments, and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of Generation’s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with credit, interest rates, and equity price. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk — Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in ITEM 1. BUSINESS —ComEd of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under EXELON CORPORATION—Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

A discussion of ComEd's results of operations for 2020 compared to 2019 is set forth under Results of Operations—ComEd in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2020, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund ComEd's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. ComEd spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd’s contractual obligations, commercial commitments, and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of ComEd’s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price and credit. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk — Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in ITEM 1. BUSINESS—PECO of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under EXELON CORPORATION—Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

A discussion of PECO's results of operations for 2020 compared to 2019 is set forth under Results of Operations—PECO in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2020, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund PECO's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. PECO spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under Credit Matters in “EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO’s contractual obligations, commercial commitments, and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of PECO’s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk—Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in ITEM 1. BUSINESS—BGE of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE's executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

A discussion of BGE's results of operations for 2020 compared to 2019 is set forth under Results of Operations—BGE in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2020, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund BGE's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. BGE spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE's contractual obligations, commercial commitments, and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of BGE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk—Exelon.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PHI

General

PHI has three reportable segments Pepco, DPL, and ACE. Its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services, and to a lesser extent, the purchase and regulated retail sale and supply of natural gas in Delaware. This segment is discussed in further detail in ITEM 1. BUSINESS — PHI of this Form 10-K.

Executive Overview

A discussion of items pertinent to PHI’s executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

A discussion of PHI’s results of operations for 2020 compared to 2019 is set forth under Results of Operations—PHI in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PHI’s business is capital intensive and requires considerable capital resources. PHI’s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper, borrowings from the Exelon money pool, or capital contributions from Exelon. PHI’s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund PHI’s capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. PHI spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment.

Cash Flows from Operating Activities

A discussion of items pertinent to PHI’s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PHI’s cash flows from investing activities is set forth under “Cash Flows from Investing Activities” in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PHI’s cash flows from financing activities is set forth under “Cash Flows from Financing Activities” in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PHI is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PHI's contractual obligations, commercial commitments, and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of PHI's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PHI

PHI is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk — Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pepco

General

Pepco operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in District of Columbia and major portions of Prince George's County and Montgomery County in Maryland. This segment is discussed in further detail in ITEM 1. BUSINESS — Pepco of this Form 10-K.

Executive Overview

A discussion of items pertinent to Pepco's executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

A discussion of Pepco's results of operations for 2020 compared to 2019 is set forth under Results of Operations—Pepco in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Pepco's business is capital intensive and requires considerable capital resources. Pepco's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, or credit facility borrowings. Pepco's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2020, Pepco had access to a revolving credit facility with aggregate bank commitments of $300 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund Pepco's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. Pepco spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, Pepco operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to Pepco's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Pepco's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Pepco's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Pepco is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Pepco's contractual obligations, commercial commitments, and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of Pepco's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Pepco

Pepco is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk — Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

DPL

General

DPL operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale and supply of natural gas in New Castle County, Delaware. This segment is discussed in further detail in ITEM 1. BUSINESS — DPL of this Form 10-K.

Executive Overview

A discussion of items pertinent to DPL's executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

A discussion of DPL's results of operations for 2020 compared to 2019 is set forth under Results of Operations—DPL in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

DPL's business is capital intensive and requires considerable capital resources. DPL's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. DPL's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where DPL no longer has access to the capital markets at reasonable terms, DPL has access to a revolving credit facility. At December 31, 2020, DPL had access to a revolving credit facility with aggregate bank commitments of $300 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund DPL's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. DPL spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, DPL operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to DPL's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to DPL's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to DPL's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to DPL is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of DPL's contractual obligations, commercial commitments, and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of DPL's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

DPL

DPL is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk—Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ACE

General

ACE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in portions of southern New Jersey. This segment is discussed in further detail in ITEM 1. BUSINESS — ACE of this Form 10-K.

Executive Overview

A discussion of items pertinent to ACE's executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2020 Compared to Year Ended December 31, 2019

A discussion of ACE's results of operations for 2020 compared to 2019 is set forth under Results of Operations—ACE in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ACE's business is capital intensive and requires considerable capital resources. ACE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, or credit facility borrowings. ACE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2020, ACE had access to a revolving credit facility with aggregate bank commitments of $300 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund ACE's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. ACE spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ACE operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ACE's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ACE's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ACE's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ACE is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ACE’s contractual obligations, commercial commitments, and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of ACE’s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ACE

ACE is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk— Exelon.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2020, Exelon's internal control over financial reporting was effective.

The effectiveness of Exelon's internal control over financial reporting as of December 31, 2020, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 24, 2021

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2020, Generation's internal control over financial reporting was effective.

February 24, 2021

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2020, ComEd's internal control over financial reporting was effective.

February 24, 2021

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2020, PECO's internal control over financial reporting was effective.

February 24, 2021

Management's Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2020, BGE's internal control over financial reporting was effective.

February 24, 2021

Management's Report on Internal Control Over Financial Reporting

The management of Pepco Holdings LLC (PHI) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PHI's management conducted an assessment of the effectiveness of PHI's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PHI's management concluded that, as of December 31, 2020, PHI's internal control over financial reporting was effective.

February 24, 2021

Management's Report on Internal Control Over Financial Reporting

The management of Potomac Electric Power Company (Pepco) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Pepco's management conducted an assessment of the effectiveness of Pepco's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Pepco's management concluded that, as of December 31, 2020, Pepco's internal control over financial reporting was effective.

February 24, 2021

Management's Report on Internal Control Over Financial Reporting

The management of Delmarva Power & Light Company (DPL) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

DPL's management conducted an assessment of the effectiveness of DPL's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, DPL's management concluded that, as of December 31, 2020, DPL's internal control over financial reporting was effective.

February 24, 2021

Management's Report on Internal Control Over Financial Reporting

The management of Atlantic City Electric Company (ACE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ACE's management conducted an assessment of the effectiveness of ACE's internal control over financial reporting as of December 31, 2020. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ACE's management concluded that, as of December 31, 2020, ACE's internal control over financial reporting was effective.

February 24, 2021

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1)(i), and the financial statement schedules listed in the index appearing under Item 15(a)(1)(ii), of Exelon Corporation and its subsidiaries (the “Company”) (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Annual Nuclear Decommissioning Asset Retirement Obligations (ARO) Assessment

As described in Notes 1 and 10 to the consolidated financial statements, the Company has a legal obligation to decommission its nuclear generation stations following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, management uses a probability-weighted cash flow model, which on a unit-by-unit basis, considers multiple scenarios that include significant estimates and assumptions such as decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Management 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. As of December 31, 2020, the nuclear decommissioning ARO was approximately $11.9 billion.

The principal considerations for our determination that performing procedures relating to the Company's annual ARO assessment is a critical audit matter are the significant judgment by management when estimating its decommissioning obligation; this in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the reasonableness of management's cash flow model and significant assumptions related to decommissioning cost studies. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's development of the inputs, assumptions, and model used in management's ARO assessment. These procedures also included, among others, testing management's process for developing the ARO estimates by evaluating the appropriateness of the cash flow model, testing the completeness and accuracy of data used by management, and evaluating the reasonableness of management's significant assumptions related to decommissioning cost studies. Professionals with specialized skill and knowledge were used to assist in evaluating the results of decommissioning cost studies.

Impairment Assessment of Long-Lived Generation Assets

As described in Notes 1 and 12 to the consolidated financial statements, the Company evaluates 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, or plans to dispose of a long-lived asset significantly before the end of its useful life. Management 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. The expected future cash flows include significant unobservable inputs including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As of December 31, 2020, the total carrying value of long-lived generation assets subject to this evaluation was approximately $22.2 billion.

The principal considerations for our determination that performing procedures relating to the Company's impairment assessment of long-lived generation assets is a critical audit matter are the significant judgment by management in assessing the recoverability of these asset groups; this in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating the reasonableness of management's significant assumptions related to revenue and generation forecasts. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's development of the inputs, assumptions, and model used to estimate the recoverability and fair value of the Company's long-lived generation asset groups. These procedures also included, among others, testing management's process for developing expected future cash flows for long-lived generation asset groups by evaluating the appropriateness of the future cash flow model, testing the completeness and accuracy of the data used by management, and evaluating the reasonableness of management's significant assumptions related to revenue and generation forecasts. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of revenue forecasts.

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. As of December 31, 2020, there were approximately $10.0 billion of regulatory assets and approximately $10.1 billion of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to management's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's judgments regarding regulatory guidance and proceedings and the related accounting implications, and calculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 24, 2021

We have served as the Company's auditor since 2000.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(2)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(2)(ii), of Exelon Generation Company, LLC and its subsidiaries (the "Company") (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Annual Nuclear Decommissioning Asset Retirement Obligations (ARO) Assessment

As described in Notes 1 and 10 to the consolidated financial statements, the Company has a legal obligation to decommission its nuclear generation stations following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, management uses a probability-weighted cash flow model, which on a unit-by-unit basis, considers multiple scenarios that include significant estimates and assumptions such as decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Management 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. As of December 31, 2020, the nuclear decommissioning ARO was approximately $11.9 billion.

The principal considerations for our determination that performing procedures relating to the Company's annual ARO assessment is a critical audit matter are the significant judgment by management when estimating its decommissioning obligation; this in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the reasonableness of management's cash flow model and significant assumptions related to decommissioning cost studies. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's development of the inputs, assumptions, and model used in management's ARO assessment. These procedures also included, among others, testing management's process for developing the ARO estimates by evaluating the appropriateness of the cash flow model, testing the completeness and accuracy of data used by management, and evaluating the reasonableness of management's significant assumptions related to decommissioning cost studies. Professionals with specialized skill and knowledge were used to assist in evaluating the results of decommissioning cost studies.

Impairment Assessment of Long-Lived Generation Assets

As described in Notes 1 and 12 to the consolidated financial statements, the Company evaluates 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, or plans to dispose of a long-lived asset significantly before the end of its useful life. Management 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. The expected future cash flows include significant unobservable inputs including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As of December 31, 2020, the total carrying value of long-lived generation assets subject to this evaluation was approximately $22.2 billion.

The principal considerations for our determination that performing procedures relating to the Company's impairment assessment of long-lived generation assets is a critical audit matter are the significant judgment by management in assessing the recoverability of these asset groups; this in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating the reasonableness of management's significant assumptions related to revenue and generation forecasts. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's development of the inputs, assumptions, and model used to estimate the recoverability and fair value of the Company's long-lived generation asset groups. These procedures also included, among others, testing management's process for developing expected future cash flows for long-lived generation asset groups by evaluating the appropriateness of the future cash flow model, testing the completeness and accuracy of the data used by management, and evaluating the reasonableness of management's significant assumptions related to revenue and generation forecasts. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of revenue forecasts.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 24, 2021

We have served as the Company's auditor since 2001.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(3)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(3)(ii), of Commonwealth Edison Company and its subsidiaries (the "Company") (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. As of December 31, 2020, there were approximately $2.0 billion of regulatory assets and approximately $6.7 billion of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to management's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's judgments regarding regulatory guidance and proceedings and the related accounting implications, and calculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 24, 2021

We have served as the Company's auditor since 2000.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of PECO Energy Company

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(4)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(4)(ii), of PECO Energy Company and its subsidiaries (the "Company") (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. As of December 31, 2020, there were approximately $801 million of regulatory assets and approximately $624 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to management’s accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company’s correspondence with regulators, evaluating the reasonableness of management’s judgments regarding regulatory guidance and proceedings and the related accounting implications, and calculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 24, 2021

We have served as the Company's auditor since 1932.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Baltimore Gas and Electric Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(5)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(5)(ii), of Baltimore Gas and Electric Company (the "Company") (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 to the financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in their financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in

accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. As of December 31, 2020, there were approximately $649 million of regulatory assets and approximately $1,139 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to management's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's judgments regarding regulatory guidance and proceedings and the related accounting implications, and calculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 24, 2021

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(6)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(6)(ii), of Pepco Holdings LLC and its subsidiaries (the “Company”) (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. As of December 31, 2020, there were approximately $2.4 billion of regulatory assets and approximately $1.6 billion of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to management's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's judgments regarding regulatory guidance and proceedings and the related accounting implications, and calculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 24, 2021

We have served as the Company's auditor since 2001.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Potomac Electric Power Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(7)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(7)(ii), of Potomac Electric Power Company (the "Company") (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 to the financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in their financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in

accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. As of December 31, 2020, there were approximately $784 million of regulatory assets and approximately $690 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to management's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's judgments regarding regulatory guidance and proceedings and the related accounting implications, and calculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 24, 2021

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Delmarva Power & Light Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(8)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(8)(ii), of Delmarva Power & Light Company (the "Company") (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 to the financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in their financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in

accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. As of December 31, 2020, there were approximately $280 million of regulatory assets and approximately $540 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to management's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's judgments regarding regulatory guidance and proceedings and the related accounting implications, and calculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 24, 2021

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Atlantic City Electric Company

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(9)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(9)(ii), of Atlantic City Electric Company and its subsidiary (the "Company") (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. As of December 31, 2020, there were approximately $470 million of regulatory assets and approximately $318 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to management's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's judgments regarding regulatory guidance and proceedings and the related accounting implications, and calculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 24, 2021

We have served as the Company's auditor since 1998.

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions, except per share data)	2020	2019	2018
Operating revenues			
Competitive businesses revenues	$ 16,400	$ 17,754	$ 19,168
Rate-regulated utility revenues	16,633	16,839	16,879
Revenues from alternative revenue programs	6	(155)	(69)
Total operating revenues	33,039	34,438	35,978
Operating expenses			
Competitive businesses purchased power and fuel	9,592	10,849	11,679
Rate-regulated utility purchased power and fuel	4,512	4,648	4,991
Operating and maintenance	9,408	8,615	9,337
Depreciation and amortization	5,014	4,252	4,353
Taxes other than income taxes	1,714	1,732	1,783
Total operating expenses	30,240	30,096	32,143
Gain on sales of assets and businesses	24	31	56
Gain on deconsolidation of business	—	1	—
Operating income	2,823	4,374	3,891
Other income and (deductions)			
Interest expense, net	(1,610)	(1,591)	(1,529)
Interest expense to affiliates	(25)	(25)	(25)
Other, net	1,145	1,227	(112)
Total other (deductions)	(490)	(389)	(1,666)
Income before income taxes	2,333	3,985	2,225
Income taxes	373	774	118
Equity in losses of unconsolidated affiliates	(6)	(183)	(28)
Net income	1,954	3,028	2,079
Net (loss) income attributable to noncontrolling interests	(9)	92	74
Net income attributable to common shareholders	$ 1,963	$ 2,936	$ 2,005
Comprehensive income, net of income taxes			
Net income	$ 1,954	$ 3,028	$ 2,079
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(40)	(65)	(66)
Actuarial loss reclassified to periodic benefit cost	190	149	247
Pension and non-pension postretirement benefit plan valuation adjustment	(357)	(289)	(143)
Unrealized (loss) gain on cash flow hedges	(3)	—	12
Unrealized gain on investments in unconsolidated affiliates	—	1	2
Unrealized gain (loss) on foreign currency translation	4	6	(10)
Other comprehensive income (loss)	(206)	(198)	42
Comprehensive income	1,748	2,830	2,121
Comprehensive (loss) income attributable to noncontrolling interests	(9)	93	75
Comprehensive income attributable to common shareholders	$ 1,757	$ 2,737	$ 2,046
Average shares of common stock outstanding:			
Basic	976	973	967
Assumed exercise and/or distributions of stock-based awards	1	1	2
Diluted(a)	977	974	969
Earnings per average common share:			
Basic	$ 2.01	$ 3.02	$ 2.07
Diluted	$ 2.01	$ 3.01	$ 2.07

(a) The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was less than 1 million for the years ended December 31, 2020 and December 31, 2019 and approximately 3 million for the year ended December 31, 2018.

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2020	2019	2018
Cash flows from operating activities			
Net income	$ 1,954	$ 3,028	$ 2,079
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	6,527	5,780	5,971
Asset impairments	591	201	50
Gain on sales of assets and businesses	(24)	(27)	(56)
Deferred income taxes and amortization of investment tax credits	309	681	(108)
Net fair value changes related to derivatives	(268)	222	294
Net realized and unrealized (gains) losses on NDT funds	(461)	(663)	303
Unrealized gain on equity investments	(186)	—	—
Other non-cash operating activities	592	613	1,131
Changes in assets and liabilities:			
Accounts receivable	697	(243)	(565)
Inventories	(85)	(87)	(37)
Accounts payable and accrued expenses	(129)	(425)	551
Option premiums (paid), net	(139)	(29)	(43)
Collateral received (posted), net	494	(438)	82
Income taxes	140	(64)	340
Pension and non-pension postretirement benefit contributions	(601)	(408)	(383)
Other assets and liabilities	(5,176)	(1,482)	(965)
Net cash flows provided by operating activities	4,235	6,659	8,644
Cash flows from investing activities			
Capital expenditures	(8,048)	(7,248)	(7,594)
Proceeds from NDT fund sales	3,341	10,051	8,762
Investment in NDT funds	(3,464)	(10,087)	(8,997)
Collection of DPP	3,771	—	—
Acquisitions of assets and businesses, net	—	(41)	(154)
Proceeds from sales of assets and businesses	46	53	91
Other investing activities	18	12	58
Net cash flows used in investing activities	(4,336)	(7,260)	(7,834)
Cash flows from financing activities			
Changes in short-term borrowings	161	781	(338)
Proceeds from short-term borrowings with maturities greater than 90 days	500	—	126
Repayments on short-term borrowings with maturities greater than 90 days	—	(125)	(1)
Issuance of long-term debt	7,507	1,951	3,115
Retirement of long-term debt	(6,440)	(1,287)	(1,786)
Dividends paid on common stock	(1,492)	(1,408)	(1,332)
Proceeds from employee stock plans	45	112	105
Other financing activities	(136)	(82)	(108)
Net cash flows provided by (used in) financing activities	145	(58)	(219)
Increase (decrease) in cash, restricted cash, and cash equivalents	44	(659)	591
Cash, restricted cash, and cash equivalents at beginning of period	1,122	1,781	1,190
Cash, restricted cash, and cash equivalents at end of period	$ 1,166	$ 1,122	$ 1,781
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 194	$ (7)	$ (69)
Increase in DPP	4,441	—	—
Increase (decrease) in PP&E related to ARO update	850	968	(107)

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

	December 31,			
(In millions)	2020		2019	
ASSETS				
Current assets				
Cash and cash equivalents		$ 663		$ 587
Restricted cash and cash equivalents		438		358
Accounts receivable				
Customer accounts receivable	3,597		4,835	
Customer allowance for credit losses	(366)		(243)	
Customer accounts receivable, net		3,231		4,592
Other accounts receivable	1,469		1,631	
Other allowance for credit losses	(71)		(48)	
Other accounts receivable, net		1,398		1,583
Mark-to-market derivative assets		644		679
Unamortized energy contract assets		38		47
Inventories, net				
Fossil fuel and emission allowances		297		312
Materials and supplies		1,425		1,456
Regulatory assets		1,228		1,170
Renewable energy credits		633		348
Assets held for sale		958		—
Other		1,609		905
Total current assets		12,562		12,037
Property, plant, and equipment (net of accumulated depreciation and amortization of $26,727 and $23,979 as of December 31, 2020 and 2019, respectively)		82,584		80,233
Deferred debits and other assets				
Regulatory assets		8,759		8,335
Nuclear decommissioning trust funds		14,464		13,190
Investments		440		464
Goodwill		6,677		6,677
Mark-to-market derivative assets		555		508
Unamortized energy contract assets		294		336
Other		2,982		3,197
Total deferred debits and other assets		34,171		32,707
Total assets[(a)]		$ 129,317		$ 124,977

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2020	2019
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 2,031	$ 1,370
Long-term debt due within one year	1,819	4,710
Accounts payable	3,562	3,560
Accrued expenses	2,078	1,981
Payables to affiliates	5	5
Regulatory liabilities	581	406
Mark-to-market derivative liabilities	295	247
Unamortized energy contract liabilities	100	132
Renewable energy credit obligation	661	443
Liabilities held for sale	375	—
Other	1,264	1,331
Total current liabilities	12,771	14,185
Long-term debt	35,093	31,329
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,035	12,351
Asset retirement obligations	12,300	10,846
Pension obligations	4,503	4,247
Non-pension postretirement benefit obligations	2,011	2,076
Spent nuclear fuel obligation	1,208	1,199
Regulatory liabilities	9,485	9,986
Mark-to-market derivative liabilities	473	393
Unamortized energy contract liabilities	238	338
Other	2,942	3,064
Total deferred credits and other liabilities	46,195	44,500
Total liabilities[(a)]	94,449	90,404
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 976 shares and 973 shares outstanding at December 31, 2020 and 2019, respectively)	19,373	19,274
Treasury stock, at cost (2 shares at December 31, 2020 and 2019)	(123)	(123)
Retained earnings	16,735	16,267
Accumulated other comprehensive loss, net	(3,400)	(3,194)
Total shareholders' equity	32,585	32,224
Noncontrolling interests	2,283	2,349
Total equity	34,868	34,573
Total liabilities and shareholders' equity	$ 129,317	$ 124,977

(a) Exelon's consolidated assets include $10,200 million and $9,532 million at December 31, 2020 and 2019, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,598 million and $3,473 million at December 31, 2020 and 2019, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 23–Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Changes in Equity

	Shareholders' Equity						
(In millions, shares in thousands)	**Issued Shares**	**Common Stock**	**Treasury Stock**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Noncontrolling Interests**	**Total Equity**
Balance, December 31, 2017	965,168	$ 18,964	$ (123)	$ 14,063	$ (3,026)	$ 2,291	$ 32,169
Net income	—	—	—	2,005	—	74	2,079
Long-term incentive plan activity	3,534	41	—	—	—	—	41
Employee stock purchase plan issuances	1,318	105	—	—	—	—	105
Sale of noncontrolling interests	—	6	—	—	—	—	6
Changes in equity of noncontrolling interests	—	—	—	—	—	(60)	(60)
Common stock dividends ($1.38/common share)	—	—	—	(1,339)	—	—	(1,339)
Other comprehensive income, net of income taxes	—	—	—	—	41	1	42
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	—	—	14	(10)	—	4
Balance, December 31, 2018	970,020	$ 19,116	$ (123)	$ 14,743	$ (2,995)	$ 2,306	$ 33,047
Net income	—	—	—	2,936	—	92	3,028
Long-term incentive plan activity	3,111	40	—	—	—	—	40
Employee stock purchase plan issuances	1,285	112	—	—	—	—	112
Sale of noncontrolling interests	—	6	—	—	—	—	6
Changes in equity of noncontrolling interests	—	—	—	—	—	(48)	(48)
Common stock dividends ($1.45/common share)	—	—	—	(1,412)	—	—	(1,412)
Other comprehensive income, net of income taxes	—	—	—	—	(199)	(1)	(200)
Balance, December 31, 2019	974,416	$ 19,274	$ (123)	$ 16,267	$ (3,194)	$ 2,349	$ 34,573
Net income (loss)	—	—	—	1,963	—	(9)	1,954
Long-term incentive plan activity	1,570	40	—	—	—	—	40
Employee stock purchase plan issuances	1,480	56	—	—	—	—	56
Sale of noncontrolling interests	—	3	—	—	—	—	3
Changes in equity of noncontrolling interests	—	—	—	—	—	(57)	(57)
Common stock dividends ($1.53/common share)	—	—	—	(1,495)	—	—	(1,495)
Other comprehensive income, net of income taxes	—	—	—	—	(206)	—	(206)
Balance, December 31, 2020	977,466	$ 19,373	$ (123)	$ 16,735	$ (3,400)	$ 2,283	$ 34,868

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions)	2020	2019	2018
Operating revenues			
Operating revenues	$ 16,392	$ 17,752	$ 19,169
Operating revenues from affiliates	1,211	1,172	1,268
Total operating revenues	17,603	18,924	20,437
Operating expenses			
Purchased power and fuel	9,592	10,849	11,679
Purchased power and fuel from affiliates	(7)	7	14
Operating and maintenance	4,613	4,131	4,803
Operating and maintenance from affiliates	555	587	661
Depreciation and amortization	2,123	1,535	1,797
Taxes other than income taxes	482	519	556
Total operating expenses	17,358	17,628	19,510
Gain on sales of assets and businesses	11	27	48
Operating income	256	1,323	975
Other income and (deductions)			
Interest expense, net	(328)	(394)	(396)
Interest expense to affiliates	(29)	(35)	(36)
Other, net	937	1,023	(178)
Total other income and (deductions)	580	594	(610)
Income before income taxes	836	1,917	365
Income taxes	249	516	(108)
Equity in losses of unconsolidated affiliates	(8)	(184)	(30)
Net income	579	1,217	443
Net (loss) income attributable to noncontrolling interests	(10)	92	73
Net income attributable to membership interest	$ 589	$ 1,125	$ 370
Comprehensive income, net of income taxes			
Net income	$ 579	$ 1,217	$ 443
Other comprehensive income (loss), net of income taxes			
Unrealized (loss) gain on cash flow hedges	(2)	—	12
Unrealized gain on investments in unconsolidated affiliates	—	1	1
Unrealized gain (loss) on foreign currency translation	4	6	(10)
Other comprehensive income	2	7	3
Comprehensive income	$ 581	$ 1,224	$ 446
Comprehensive (loss) income attributable to noncontrolling interests	(10)	93	74
Comprehensive income attributable to membership interest	$ 591	$ 1,131	$ 372

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2020	2019	2018
Cash flows from operating activities			
Net income	$ 579	$ 1,217	$ 443
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	3,636	3,063	3,415
Asset impairments	563	201	50
Gain on sales of assets and businesses	(11)	(27)	(48)
Deferred income taxes and amortization of investment tax credits	78	361	(451)
Net fair value changes related to derivatives	(270)	228	307
Net realized and unrealized (gains) losses on NDT fund investments	(461)	(663)	303
Unrealized gain on equity investments	(186)	—	—
Other non-cash operating activities	18	(124)	298
Changes in assets and liabilities:			
Accounts receivable	1,125	(186)	(359)
Receivables from and payables to affiliates, net	24	(52)	8
Inventories	(77)	(47)	(12)
Accounts payable and accrued expenses	(343)	(248)	376
Option premiums paid, net	(139)	(29)	(43)
Collateral received (posted), net	479	(481)	64
Income taxes	186	302	(193)
Pension and non-pension postretirement benefit contributions	(255)	(175)	(139)
Other assets and liabilities	(4,362)	(467)	(158)
Net cash flows provided by operating activities	584	2,873	3,861
Cash flows from investing activities			
Capital expenditures	(1,747)	(1,845)	(2,242)
Proceeds from NDT fund sales	3,341	10,051	8,762
Investment in NDT funds	(3,464)	(10,087)	(8,997)
Collection of DPP	3,771	—	—
Proceeds from sales of assets and businesses	46	52	90
Acquisitions of assets and businesses, net	—	(41)	(154)
Other investing activities	11	3	10
Net cash flows provided by (used in) investing activities	1,958	(1,867)	(2,531)
Cash flows from financing activities			
Change in short-term borrowings	20	320	—
Proceeds from short-term borrowings with maturities greater than 90 days	500	—	—
Issuance of long-term debt	3,155	42	15
Retirement of long-term debt	(4,334)	(813)	(141)
Retirement of long-term debt to affiliate	(550)	—	—
Changes in Exelon intercompany money pool	285	(100)	46
Distributions to member	(1,734)	(899)	(1,001)
Contributions from member	64	41	155
Other financing activities	(70)	(51)	(55)
Net cash flows used in financing activities	(2,664)	(1,460)	(981)
(Decrease) increase in cash, restricted cash, and cash equivalents	(122)	(454)	349
Cash, restricted cash, and cash equivalents at beginning of period	449	903	554
Cash, restricted cash, and cash equivalents at end of period	$ 327	$ 449	$ 903
Supplemental cash flow information			
Decrease in capital expenditures not paid	$ (88)	$ (34)	$ (199)
Increase in DPP	4,441	—	—
Increase (decrease) in PP&E related to ARO update	850	959	(130)

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 226	$ 303
Restricted cash and cash equivalents	89	146
Accounts receivable		
Customer accounts receivable	1,330	2,973
Customer allowance for credit losses	(32)	(80)
Customer accounts receivable, net	1,298	2,893
Other accounts receivable	352	619
Other accounts receivable, net	352	619
Mark-to-market derivative assets	644	675
Receivables from affiliates	153	190
Unamortized energy contract assets	38	47
Inventories, net		
Fossil fuel and emission allowances	233	236
Materials and supplies	978	1,026
Renewable energy credits	621	336
Assets held for sale	958	—
Other	1,357	605
Total current assets	6,947	7,076
Property, plant, and equipment (net of accumulated depreciation and amortization of $13,370 and $12,017 as of December 31, 2020 and 2019, respectively)	22,214	24,193
Deferred debits and other assets		
Nuclear decommissioning trust funds	14,464	13,190
Investments	184	235
Goodwill	47	47
Mark-to-market derivative assets	555	508
Prepaid pension asset	1,558	1,438
Unamortized energy contract assets	293	336
Deferred income taxes	6	12
Other	1,826	1,960
Total deferred debits and other assets	18,933	17,726
Total assets[(a)]	$ 48,094	$ 48,995

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2020	2019
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 840	$ 320
Long-term debt due within one year	197	2,624
Long-term debt to affiliates due within one year	—	558
Accounts payable	1,253	1,692
Accrued expenses	788	786
Payables to affiliates	107	117
Borrowings from Exelon intercompany money pool	285	—
Mark-to-market derivative liabilities	262	215
Unamortized energy contract liabilities	7	17
Renewable energy credit obligation	661	443
Liabilities held for sale	375	—
Other	444	517
Total current liabilities	5,219	7,289
Long-term debt	5,566	4,464
Long-term debt to affiliates	324	328
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,656	3,752
Asset retirement obligations	12,054	10,603
Non-pension postretirement benefit obligations	858	878
Spent nuclear fuel obligation	1,208	1,199
Payables to affiliates	3,017	3,103
Mark-to-market derivative liabilities	205	123
Unamortized energy contract liabilities	3	11
Other	1,308	1,415
Total deferred credits and other liabilities	22,309	21,084
Total liabilities[(a)]	33,418	33,165
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,624	9,566
Undistributed earnings	2,805	3,950
Accumulated other comprehensive loss, net	(30)	(32)
Total member's equity	12,399	13,484
Noncontrolling interests	2,277	2,346
Total equity	14,676	15,830
Total liabilities and equity	$ 48,094	$ 48,995

(a) Generation's consolidated assets include $10,182 million and $9,512 million at December 31, 2020 and 2019, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $3,572 million and $3,429 million at December 31, 2020 and 2019, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 23–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

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2017	$ 9,357	$ 4,349	$ (37)	$ 2,290	$ 15,959
Net income	—	370	—	73	443
Sale of noncontrolling interests	6	—	—	—	6
Changes in equity of noncontrolling interests	—	—	—	(60)	(60)
Distributions to member	—	(1,001)	—	—	(1,001)
Contributions from member	155	—	—	—	155
Other comprehensive income, net of income taxes	—	—	2	1	3
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	6	(3)	—	3
Balance, December 31, 2018	$ 9,518	$ 3,724	$ (38)	$ 2,304	$ 15,508
Net income	—	1,125	—	92	1,217
Sale of noncontrolling interests	7	—	—	—	7
Changes in equity of noncontrolling interests	—	—	—	(48)	(48)
Distributions to member	—	(899)	—	—	(899)
Contributions from member	41	—	—	—	41
Other comprehensive income (loss), net of income taxes	—	—	6	(2)	4
Balance, December 31, 2019	$ 9,566	$ 3,950	$ (32)	$ 2,346	$ 15,830
Net income	—	589	—	(10)	579
Sale of noncontrolling interests	3	—	—	—	3
Changes in equity of noncontrolling interests	—	—	—	(59)	(59)
Distribution to member of deferred taxes associated with net retirement benefit obligation	(9)	—	—	—	(9)
Distributions to member	—	(1,734)	—	—	(1,734)
Contributions from member	64	—	—	—	64
Other comprehensive income, net of income taxes	—	—	2	—	2
Balance, December 31, 2020	$ 9,624	$ 2,805	$ (30)	$ 2,277	$ 14,676

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2020	2019	2018
Operating revenues			
Electric operating revenues	$ 5,914	$ 5,850	$ 5,884
Revenues from alternative revenue programs	(47)	(133)	(29)
Operating revenues from affiliates	37	30	27
Total operating revenues	5,904	5,747	5,882
Operating expenses			
Purchased power	1,653	1,565	1,626
Purchased power from affiliates	345	376	529
Operating and maintenance	1,231	1,041	1,068
Operating and maintenance from affiliates	289	264	267
Depreciation and amortization	1,133	1,033	940
Taxes other than income taxes	299	301	311
Total operating expenses	4,950	4,580	4,741
Gain on sales of assets	—	4	5
Operating income	954	1,171	1,146
Other income and (deductions)			
Interest expense, net	(369)	(346)	(334)
Interest expense to affiliates	(13)	(13)	(13)
Other, net	43	39	33
Total other income and (deductions)	(339)	(320)	(314)
Income before income taxes	615	851	832
Income taxes	177	163	168
Net income	$ 438	$ 688	$ 664
Comprehensive income	$ 438	$ 688	$ 664

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2020	2019	2018
Cash flows from operating activities			
Net income	$ 438	$ 688	$ 664
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	1,133	1,033	940
Deferred income taxes and amortization of investment tax credits	228	109	259
Other non-cash operating activities	202	265	242
Changes in assets and liabilities:			
Accounts receivable	(10)	(34)	(136)
Receivables from and payables to affiliates, net	(1)	(12)	26
Inventories	(13)	(16)	1
Accounts payable and accrued expenses	63	(51)	70
Counterparty received (posted), net	14	48	11
Income taxes	8	95	62
Pension and non-pension postretirement benefit contributions	(148)	(77)	(42)
Other assets and liabilities	(590)	(345)	(348)
Net cash flows provided by operating activities	1,324	1,703	1,749
Cash flows from investing activities			
Capital expenditures	(2,217)	(1,915)	(2,126)
Other investing activities	2	29	29
Net cash flows used in investing activities	(2,215)	(1,886)	(2,097)
Cash flows from financing activities			
Changes in short-term borrowings	193	130	—
Issuance of long-term debt	1,000	700	1,350
Retirement of long-term debt	(500)	(300)	(840)
Dividends paid on common stock	(499)	(508)	(459)
Contributions from parent	712	250	500
Other financing activities	(13)	(16)	(17)
Net cash flows provided by financing activities	893	256	534
Increase in cash, restricted cash, and cash equivalents	2	73	186
Cash, restricted cash, and cash equivalents at beginning of period	403	330	144
Cash, restricted cash, and cash equivalents at end of period	$ 405	$ 403	$ 330
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 109	$ (37)	$ 11

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

	December 31,			
(In millions)	**2020**		**2019**	
ASSETS				
Current assets				
Cash and cash equivalents		$ 83		$ 90
Restricted cash and cash equivalents		279		150
Accounts receivable				
Customer accounts receivable	656		604	
Customer allowance for credit losses	(97)		(59)	
Customer accounts receivable, net		559		545
Other accounts receivable	239		306	
Other allowance for credit losses	(21)		(20)	
Other accounts receivable, net		218		286
Receivables from affiliates		22		28
Inventories, net		170		159
Regulatory assets		279		281
Other		49		44
Total current assets		1,659		1,583
Property, plant, and equipment (net of accumulated depreciation and amortization of $5,672 and $5,168 as of December 31, 2020 and December 31, 2019, respectively)		24,557		23,107
Deferred debits and other assets				
Regulatory assets		1,749		1,480
Investments		6		6
Goodwill		2,625		2,625
Receivables from affiliates		2,541		2,622
Prepaid pension asset		1,022		995
Other		307		347
Total deferred debits and other assets		8,250		8,075
Total assets		$ 34,466		$ 32,765

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 323	$ 130
Long-term debt due within one year	350	500
Accounts payable	683	527
Accrued expenses	390	385
Payables to affiliates	96	103
Customer deposits	86	118
Regulatory liabilities	289	200
Mark-to-market derivative liabilities	33	32
Other	143	122
Total current liabilities	2,393	2,117
Long-term debt	8,633	7,991
Long-term debt to financing trusts	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,341	4,021
Asset retirement obligations	126	128
Non-pension postretirement benefits obligations	173	180
Regulatory liabilities	6,403	6,542
Mark-to-market derivative liabilities	268	269
Other	595	635
Total deferred credits and other liabilities	11,906	11,775
Total liabilities	23,137	22,088
Commitments and contingencies		
Shareholders' equity		
Common stock ($12.50 par value, 250 shares authorized, 127 shares outstanding at December 31, 2020 and 2019)	1,588	1,588
Other paid-in capital	8,285	7,572
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	3,095	3,156
Total shareholders' equity	11,329	10,677
Total liabilities and shareholders' equity	$ 34,466	$ 32,765

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2017	$ 1,588	$ 6,822	$ (1,639)	$ 2,771	$ 9,542
Net income	—	—	664	—	664
Appropriation of retained earnings for future dividends	—	—	(664)	664	—
Common stock dividends	—	—	—	(459)	(459)
Contributions from parent	—	500	—	—	500
Balance, December 31, 2018	$ 1,588	$ 7,322	$ (1,639)	$ 2,976	$ 10,247
Net income	—	—	688	—	688
Appropriation of retained earnings for future dividends	—	—	(688)	688	—
Common stock dividends	—	—	—	(508)	(508)
Contributions from parent	—	250	—	—	250
Balance, December 31, 2019	$ 1,588	$ 7,572	$ (1,639)	$ 3,156	$ 10,677
Net income	—	—	438	—	438
Appropriation of retained earnings for future dividends	—	—	(438)	438	—
Common stock dividends	—	—	—	(499)	(499)
Contributions from parent	—	713	—	—	713
Balance, December 31, 2020	$ 1,588	$ 8,285	$ (1,639)	$ 3,095	$ 11,329

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2020	2019	2018
Operating revenues			
Electric operating revenues	$ 2,519	$ 2,505	$ 2,469
Natural gas operating revenues	514	610	568
Revenues from alternative revenue programs	16	(21)	(7)
Operating revenues from affiliates	9	6	8
Total operating revenues	3,058	3,100	3,038
Operating expenses			
Purchased power	645	610	734
Purchased fuel	185	262	230
Purchased power from affiliates	188	157	126
Operating and maintenance	816	707	742
Operating and maintenance from affiliates	159	154	156
Depreciation and amortization	347	333	301
Taxes other than income taxes	172	165	163
Total operating expenses	2,512	2,388	2,452
Gain on sales of assets	—	1	1
Operating income	546	713	587
Other income and (deductions)			
Interest expense, net	(136)	(124)	(115)
Interest expense to affiliates, net	(11)	(12)	(14)
Other, net	18	16	8
Total other income and (deductions)	(129)	(120)	(121)
Income before income taxes	417	593	466
Income taxes	(30)	65	6
Net income	$ 447	$ 528	$ 460
Comprehensive income	$ 447	$ 528	$ 460

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2020	2019	2018
Cash flows from operating activities			
Net income	$ 447	$ 528	$ 460
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	347	333	301
Gain on sale of assets	—	(1)	—
Deferred income taxes and amortization of investment tax credits	(23)	20	(5)
Other non-cash operating activities	24	38	51
Changes in assets and liabilities:			
Accounts receivable	(88)	(29)	(74)
Receivables from and payables to affiliates, net	(6)	(5)	7
Inventories	(1)	4	(14)
Accounts payable and accrued expenses	63	(11)	(3)
Income taxes	31	(34)	15
Pension and non-pension postretirement benefit contributions	(18)	(28)	(28)
Other assets and liabilities	1	(64)	29
Net cash flows provided by operating activities	777	751	739
Cash flows from investing activities			
Capital expenditures	(1,147)	(939)	(849)
Changes in Exelon intercompany money pool	68	(68)	—
Other investing activities	7	(1)	9
Net cash flows used in investing activities	(1,072)	(1,008)	(840)
Cash flows from financing activities			
Issuance of long-term debt	350	325	700
Retirement of long-term debt	—	—	(500)
Dividends paid on common stock	(340)	(358)	(306)
Contributions from parent	248	188	89
Changes in Exelon intercompany money pool	40	—	—
Other financing activities	(4)	(6)	(22)
Net cash flows provided by (used in) financing activities	294	149	(39)
Decrease in cash, restricted cash, and cash equivalents	(1)	(108)	(140)
Cash, restricted cash, and cash equivalents at beginning of period	27	135	275
Cash, restricted cash, and cash equivalents at end of period	$ 26	$ 27	$ 135
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 55	$ 40	$ (12)

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents	$	19	$	21
Restricted cash and cash equivalents		7		6
Accounts receivable				
Customer accounts receivable	511		412	
Customer allowance for credit losses	(116)		(55)	
Customer accounts receivable, net		395		357
Other accounts receivable	130		145	
Other allowance for credit losses	(8)		(7)	
Other accounts receivable, net		122		138
Receivables from affiliates		2		1
Receivable from Exelon intercompany money pool		—		68
Inventories, net				
Fossil fuel		33		36
Materials and supplies		38		35
Regulatory assets		25		41
Other		21		19
Total current assets		662		722
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,843 and $3,718 as of December 31, 2020 and 2019, respectively)		10,181		9,292
Deferred debits and other assets				
Regulatory assets		776		554
Investments		30		27
Receivables from affiliates		475		480
Prepaid pension asset		375		365
Other		32		29
Total deferred debits and other assets		1,688		1,455
Total assets	$	12,531	$	11,469

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 300	$ —
Accounts payable	479	387
Accrued expenses	129	101
Payables to affiliates	50	55
Borrowings from Exelon intercompany money pool	40	—
Customer deposits	59	69
Regulatory liabilities	121	91
Other	30	19
Total current liabilities	1,208	722
Long-term debt	3,453	3,405
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,242	2,080
Asset retirement obligations	29	28
Non-pension postretirement benefits obligations	286	288
Regulatory liabilities	503	510
Other	93	74
Total deferred credits and other liabilities	3,153	2,980
Total liabilities	7,998	7,291
Commitments and contingencies		
Shareholder's equity		
Common stock (No par value, 500 shares authorized, 170 shares outstanding at December 31, 2020 and 2019)	3,014	2,766
Retained earnings	1,519	1,412
Total shareholder's equity	4,533	4,178
Total liabilities and shareholder's equity	$ 12,531	$ 11,469

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholder's Equity
Balance, December 31, 2017	$ 2,489	$ 1,087	$ 1	$ 3,577
Net income	—	460	—	460
Common stock dividends	—	(306)	—	(306)
Contributions from parent	89	—	—	89
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	1	(1)	—
Balance, December 31, 2018	$ 2,578	$ 1,242	$ —	$ 3,820
Net income	—	528	—	528
Common stock dividends	—	(358)	—	(358)
Contributions from parent	188	—	—	188
Balance, December 31, 2019	$ 2,766	$ 1,412	$ —	$ 4,178
Net income	—	447	—	447
Common stock dividends	—	(340)	—	(340)
Contributions from parent	248	—	—	248
Balance, December 31, 2020	$ 3,014	$ 1,519	$ —	$ 4,533

Baltimore Gas and Electric Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2020	2019	2018
Operating revenues			
Electric operating revenues	$ 2,323	$ 2,368	$ 2,428
Natural gas operating revenues	739	700	738
Revenues from alternative revenue programs	16	12	(26)
Operating revenues from affiliates	20	26	29
Total operating revenues	3,098	3,106	3,169
Operating expenses			
Purchased power	509	585	671
Purchased fuel	171	181	254
Purchased power and fuel from affiliates	311	286	257
Operating and maintenance	617	600	615
Operating and maintenance from affiliates	172	160	162
Depreciation and amortization	550	502	483
Taxes other than income taxes	268	260	254
Total operating expenses	2,598	2,574	2,696
Gain on sales of assets	—	—	1
Operating income	500	532	474
Other income and (deductions)			
Interest expense, net	(133)	(121)	(106)
Other, net	23	28	19
Total other income and (deductions)	(110)	(93)	(87)
Income before income taxes	390	439	387
Income taxes	41	79	74
Net income	$ 349	$ 360	$ 313
Comprehensive income	$ 349	$ 360	$ 313

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2020	2019	2018
Cash flows from operating activities			
Net income	$ 349	$ 360	$ 313
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	550	502	483
Deferred income taxes and amortization of investment tax credits	37	130	76
Other non-cash operating activities	97	85	58
Changes in assets and liabilities:			
Accounts receivable	(165)	25	8
Receivables from and payables to affiliates, net	(8)	1	12
Inventories	10	(1)	2
Accounts payable and accrued expenses	102	(43)	(1)
Collateral (posted) received, net	—	(4)	4
Income taxes	60	(67)	(20)
Pension and non-pension postretirement benefit contributions	(78)	(48)	(54)
Other assets and liabilities	(70)	(192)	(92)
Net cash flows provided by operating activities	884	748	789
Cash flows from investing activities			
Capital expenditures	(1,247)	(1,145)	(959)
Other investing activities	2	8	9
Net cash flows used in investing activities	(1,245)	(1,137)	(950)
Cash flows from financing activities			
Changes in short-term borrowings	(76)	40	(42)
Issuance of long-term debt	400	400	300
Dividends paid on common stock	(246)	(224)	(209)
Contributions from parent	411	193	109
Other financing activities	(8)	(8)	(2)
Net cash flows provided by financing activities	481	401	156
Increase (decrease) in cash, restricted cash, and cash equivalents	120	12	(5)
Cash, restricted cash, and cash equivalents at beginning of period	25	13	18
Cash, restricted cash, and cash equivalents at end of period	$ 145	$ 25	$ 13
Supplemental cash flow information			
Increase in capital expenditures not paid	$ 53	$ 6	$ 50

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Balance Sheets

(In millions)	December 31, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents		$ 144		$ 24
Restricted cash and cash equivalents		1		1
Accounts receivable				
Customer accounts receivable	487		329	
Customer allowance for credit losses	(35)		(12)	
Customer accounts receivable, net		452		317
Other accounts receivable	117		152	
Other allowance for credit losses	(9)		(5)	
Other accounts receivable, net		108		147
Receivables from affiliates		3		1
Inventories, net				
Fossil fuel		25		30
Materials and supplies		41		46
Prepaid utility taxes		—		78
Regulatory assets		168		183
Other		6		6
Total current assets		948		833
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,034 and $3,834 as of December 31, 2020 and 2019, respectively)		9,872		8,990
Deferred debits and other assets				
Regulatory assets		481		454
Investments		10		7
Prepaid pension asset		270		264
Other		69		86
Total deferred debits and other assets		830		811
Total assets		$ 11,650		$ 10,634

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 76
Long-term debt due within one year	300	—
Accounts payable	346	243
Accrued expenses	205	152
Payables to affiliates	61	66
Customer deposits	110	120
Regulatory liabilities	30	33
Other	91	63
Total current liabilities	1,143	753
Long-term debt	3,364	3,270
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,521	1,396
Asset retirement obligations	23	22
Non-pension postretirement benefits obligations	189	199
Regulatory liabilities	1,109	1,195
Other	104	116
Total deferred credits and other liabilities	2,946	2,928
Total liabilities	7,453	6,951
Commitments and contingencies		
Shareholder's equity		
Common stock (No par value, 0 shares[a] authorized, 0 shares[a] outstanding at December 31, 2020 and 2019)	2,318	1,907
Retained earnings	1,879	1,776
Total shareholder's equity	4,197	3,683
Total liabilities and shareholder's equity	$ 11,650	$ 10,634

(a) In millions, shares round to zero. Number of shares is 1,500 authorized and 1,000 outstanding at December 31, 2020 and 2019.

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 1,605	$ 1,536	$ 3,141
Net income	—	313	313
Common stock dividends	—	(209)	(209)
Contributions from parent	109	—	109
Balance, December 31, 2018	$ 1,714	$ 1,640	$ 3,354
Net income	—	360	360
Common stock dividends	—	(224)	(224)
Contributions from parent	193	—	193
Balance, December 31, 2019	$ 1,907	$ 1,776	$ 3,683
Net income	—	349	349
Common stock dividends	—	(246)	(246)
Contributions from parent	411	—	411
Balance, December 31, 2020	$ 2,318	$ 1,879	$ 4,197

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2020	2019	2018
Operating revenues			
Electric operating revenues	$ 4,463	$ 4,639	$ 4,609
Natural gas operating revenues	162	167	181
Revenues from alternative revenue programs	21	(14)	(7)
Operating revenues from affiliates	17	14	15
Total operating revenues	4,663	4,806	4,798
Operating expenses			
Purchased power	1,279	1,371	1,387
Purchased fuel	69	75	89
Purchased power from affiliates	366	352	355
Operating and maintenance	940	939	978
Operating and maintenance from affiliates	159	143	152
Depreciation and amortization	782	754	740
Taxes other than income taxes	450	450	455
Total operating expenses	4,045	4,084	4,156
Gain on sales of assets	11	—	1
Operating income	629	722	643
Other income and (deductions)			
Interest expense, net	(268)	(263)	(261)
Other, net	57	55	43
Total other income and (deductions)	(211)	(208)	(218)
Income before income taxes	418	514	425
Income taxes	(77)	38	33
Equity in earnings of unconsolidated affiliate	—	1	1
Net income	$ 495	$ 477	$ 393
Comprehensive income	$ 495	$ 477	$ 393

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2020	2019	2018
Cash flows from operating activities			
Net income	$ 495	$ 477	$ 393
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	782	754	740
Deferred income taxes and amortization of investment tax credits	(97)	(7)	30
Other non-cash operating activities	103	161	150
Changes in assets and liabilities:			
Accounts receivable	(159)	(39)	(2)
Receivables from and payables to affiliates, net	3	3	8
Inventories	(6)	(27)	(14)
Accounts payable and accrued expenses	49	(17)	45
Income taxes	(25)	16	34
Pension and non-pension postretirement benefit contributions	(39)	(25)	(74)
Other assets and liabilities	(104)	(179)	(178)
Net cash flows provided by operating activities	1,002	1,117	1,132
Cash flows from investing activities			
Capital expenditures	(1,604)	(1,355)	(1,375)
Other investing activities	7	(3)	4
Net cash flows used in investing activities	(1,597)	(1,358)	(1,371)
Cash flows from financing activities			
Changes in short-term borrowings	160	154	(296)
Proceeds from short-term borrowings with maturities greater than 90 days	—	—	125
Repayments of short-term borrowings with maturities greater than 90 days	—	(125)	—
Issuance of long-term debt	602	485	750
Retirement of long-term debt	(128)	(157)	(299)
Change in Exelon intercompany money pool	9	12	—
Distributions to member	(553)	(526)	(326)
Contributions from member	494	398	385
Other financing activities	(10)	(5)	(9)
Net cash flows provided by financing activities	574	236	330
(Decrease) increase in cash, restricted cash, and cash equivalents	(21)	(5)	91
Cash, restricted cash, and cash equivalents at beginning of period	181	186	95
Cash, restricted cash, and cash equivalents at end of period	$ 160	$ 181	$ 186
Supplemental cash flow information			
Increase in capital expenditures not paid	$ 54	$ 2	$ 93

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2020		2019	
ASSETS				
Current assets				
Cash and cash equivalents	$	111	$	131
Restricted cash and cash equivalents		39		36
Accounts receivable				
Customer accounts receivable	611		516	
Customer allowance for credit losses	(86)		(37)	
Customer accounts receivable, net		525		479
Other accounts receivable	260		190	
Other allowance for credit losses	(33)		(16)	
Other accounts receivable, net		227		174
Receivable from affiliates		8		1
Inventories, net				
Fossil fuel		6		8
Materials and supplies		198		190
Regulatory assets		440		412
Other		45		49
Total current assets		1,599		1,480
Property, plant, and equipment (net of accumulated depreciation and amortization of $1,811 and $1,213 as of December 31, 2020 and 2019, respectively)		15,377		14,296
Deferred debits and other assets				
Regulatory assets		1,933		2,061
Investments		140		135
Goodwill		4,005		4,005
Prepaid pension asset		365		406
Deferred income taxes		10		13
Other		307		323
Total deferred debits and other assets		6,760		6,943
Total assets[(a)]	$	23,736	$	22,719

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 368	$ 208
Long-term debt due within one year	347	103
Accounts payable	539	462
Accrued expenses	299	296
Payables to affiliates	104	98
Borrowings from Exelon intercompany money pool	21	12
Customer deposits	106	117
Regulatory liabilities	137	70
Unamortized energy contract liabilities	92	115
Other	141	131
Total current liabilities	2,154	1,612
Long-term debt	6,659	6,460
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,439	2,278
Asset retirement obligations	59	57
Non-pension postretirement benefit obligations	86	93
Regulatory liabilities	1,438	1,707
Unamortized energy contract liabilities	235	327
Other	622	577
Total deferred credits and other liabilities	4,879	5,039
Total liabilities(a)	13,692	13,111
Commitments and contingencies		
Member's equity		
Membership interest	10,112	9,618
Undistributed (losses) gains	(68)	(10)
Total member's equity	10,044	9,608
Total liabilities and member's equity	$ 23,736	$ 22,719

(a) PHI's consolidated total assets include $18 million and $20 million at December 31, 2020 and 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 $26 million and $44 million at December 31, 2020 and 2019, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 23 - Variable Interest Entities for additional information.

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Changes in Equity

(In millions)	Membership Interest	Undistributed (Losses)/Gains	Total Member's Equity
Balance, December 31, 2017	$ 8,835	$ (28)	$ 8,807
Net income	—	393	393
Distribution to member	—	(326)	(326)
Contributions from member	385	—	385
Balance, December 31, 2018	$ 9,220	$ 39	$ 9,259
Net Income	—	477	477
Distribution to member	—	(526)	(526)
Contributions from member	398	—	398
Balance, December 31, 2019	$ 9,618	$ (10)	$ 9,608
Net income	—	495	495
Distribution to member	—	(553)	(553)
Contributions from member	494	—	494
Balance, December 31, 2020	$ 10,112	$ (68)	$ 10,044

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2020	2019	2018
Operating revenues			
Electric operating revenues	$ 2,102	$ 2,258	$ 2,233
Revenues from alternative revenue programs	40	(3)	(7)
Operating revenues from affiliates	7	5	6
Total operating revenues	2,149	2,260	2,232
Operating expenses			
Purchased power	324	401	448
Purchased power from affiliate	278	264	206
Operating and maintenance	248	273	275
Operating and maintenance from affiliates	205	209	226
Depreciation and amortization	377	374	385
Taxes other than income taxes	367	378	379
Total operating expenses	1,799	1,899	1,919
Gain on sales of assets	9	—	—
Operating income	359	361	313
Other income and (deductions)			
Interest expense, net	(138)	(133)	(128)
Other, net	38	31	31
Total other income and (deductions)	(100)	(102)	(97)
Income before income taxes	259	259	216
Income taxes	(7)	16	11
Net income	$ 266	$ 243	$ 205
Comprehensive income	$ 266	$ 243	$ 205

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2020	2019	2018
Cash flows from operating activities			
Net income	$ 266	$ 243	$ 205
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	377	374	385
Deferred income taxes and amortization of investment tax credits	(46)	1	(20)
Other non-cash operating activities	(23)	56	67
Changes in assets and liabilities:			
Accounts receivable	(67)	(22)	(5)
Receivables from and payables to affiliates, net	(12)	5	(17)
Inventories	1	(19)	(6)
Accounts payable and accrued expenses	41	(39)	59
Income taxes	(1)	9	(13)
Pension and non-pension postretirement benefit contributions	(11)	(14)	(17)
Other assets and liabilities	(24)	(82)	(164)
Net cash flows provided by operating activities	501	512	474
Cash flows from investing activities			
Capital expenditures	(773)	(626)	(656)
Other investing activities	—	3	2
Net cash flows used in investing activities	(773)	(623)	(654)
Cash flows from financing activities			
Changes in short-term borrowings	(47)	42	14
Issuance of long-term debt	300	260	200
Retirement of long-term debt	(3)	(125)	(14)
Dividends paid on common stock	(232)	(213)	(169)
Contributions from parent	262	160	166
Other financing activities	(6)	(3)	(4)
Net cash flows provided by financing activities	274	121	193
Increase in cash, restricted cash, and cash equivalents	2	10	13
Cash, restricted cash, and cash equivalents at beginning of period	63	53	40
Cash, restricted cash, and cash equivalents at end of period	$ 65	$ 63	$ 53
Supplemental cash flow information			
Increase in capital expenditures not paid	$ 1	$ 39	$ 20

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2020		December 31, 2019	
ASSETS				
Current assets				
Cash and cash equivalents		$ 30		$ 30
Restricted cash and cash equivalents		35		33
Accounts receivable				
Customer accounts receivable	279		244	
Customer allowance for credit losses	(32)		(13)	
Customer accounts receivable, net		247		231
Other accounts receivable	131		98	
Other allowance for credit losses	(13)		(7)	
Other accounts receivable, net		118		91
Receivables from affiliates		2		—
Inventories, net		111		112
Regulatory assets		214		188
Other		13		11
Total current assets		770		696
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,697 and $3,517 as of December 31, 2020 and 2019, respectively)		7,456		6,909
Deferred debits and other assets				
Regulatory assets		570		584
Investments		115		110
Prepaid pension asset		284		296
Other		69		66
Total deferred debits and other assets		1,038		1,056
Total assets		$ 9,264		$ 8,661

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 35	$ 82
Long-term debt due within one year	3	2
Accounts payable	226	195
Accrued expenses	164	156
Payables to affiliates	55	66
Customer deposits	51	57
Regulatory liabilities	46	8
Merger related obligation	33	39
Current portion of DC PLUG obligation	30	30
Other	31	22
Total current liabilities	674	657
Long-term debt	3,162	2,862
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,189	1,131
Asset retirement obligations	39	41
Non-pension postretirement benefit obligations	13	20
Regulatory liabilities	644	746
Other	340	297
Total deferred credits and other liabilities	2,225	2,235
Total liabilities	6,061	5,754
Commitments and contingencies		
Shareholder's equity		
Common stock ($0.01 par value, 200 shares authorized, 0 shares[(a)] outstanding at December 31, 2020 and 2019)	2,058	1,796
Retained earnings	1,145	1,111
Total shareholder's equity	3,203	2,907
Total liabilities and shareholder's equity	$ 9,264	$ 8,661

(a) In millions, shares round to zero. Number of shares is 100 outstanding at December 31, 2020 and 2019.

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 1,470	$ 1,045	$ 2,515
Net income	—	205	205
Common stock dividends	—	(169)	(169)
Contributions from parent	166	—	166
Balance, December 31, 2018	$ 1,636	$ 1,081	$ 2,717
Net income	—	243	243
Common stock dividends	—	(213)	(213)
Contributions from parent	160	—	160
Balance, December 31, 2019	$ 1,796	$ 1,111	$ 2,907
Net income	—	266	266
Common stock dividends	—	(232)	(232)
Contributions from parent	262	—	262
Balance, December 31, 2020	$ 2,058	$ 1,145	$ 3,203

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2020	2019	2018
Operating revenues			
Electric operating revenues	$ 1,107	$ 1,143	$ 1,139
Natural gas operating revenues	162	167	181
Revenues from alternative revenue programs	(7)	(11)	4
Operating revenues from affiliates	9	7	8
Total operating revenues	1,271	1,306	1,332
Operating expenses			
Purchased power	359	381	352
Purchased fuel	69	75	89
Purchased power from affiliates	75	70	120
Operating and maintenance	208	171	182
Operating and maintenance from affiliates	153	152	162
Depreciation and amortization	191	184	182
Taxes other than income taxes	65	56	56
Total operating expenses	1,120	1,089	1,143
Gain on sales of assets	—	—	1
Operating income	151	217	190
Other income and (deductions)			
Interest expense, net	(61)	(61)	(58)
Other, net	10	13	10
Total other income and (deductions)	(51)	(48)	(48)
Income before income taxes	100	169	142
Income taxes	(25)	22	22
Net income	$ 125	$ 147	$ 120
Comprehensive income	$ 125	$ 147	$ 120

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2020	2019	2018
Cash flows from operating activities			
Net income	$ 125	$ 147	$ 120
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	191	184	182
Deferred income taxes and amortization of investment tax credits	(13)	(7)	24
Other non-cash operating activities	51	27	24
Changes in assets and liabilities:			
Accounts receivable	(34)	(5)	8
Receivables from and payables to affiliates, net	8	(5)	(9)
Inventories	(5)	(6)	(3)
Accounts payable and accrued expenses	4	3	11
Income taxes	(25)	12	2
Pension and non-pension postretirement benefit contributions	—	(1)	—
Other assets and liabilities	(30)	(55)	(7)
Net cash flows provided by operating activities	272	294	352
Cash flows from investing activities			
Capital expenditures	(424)	(348)	(364)
Other investing activities	(3)	1	2
Net cash flows used in investing activities	(427)	(347)	(362)
Cash flows from financing activities			
Change in short-term borrowings	90	56	(216)
Issuance of long-term debt	178	75	200
Retirement of long-term debt	(80)	(12)	(4)
Dividends paid on common stock	(141)	(139)	(96)
Contributions from parent	112	63	150
Other financing activities	(2)	(1)	(2)
Net cash flows provided by financing activities	157	42	32
Increase (decrease) in cash and cash equivalents	2	(11)	22
Cash and cash equivalents at beginning of period	13	24	2
Cash and cash equivalents at end of period	$ 15	$ 13	$ 24
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 20	$ (4)	$ 22

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 15	$ 13
Accounts receivable		
Customer accounts receivable	176	152
Customer allowance for credit losses	(22)	(11)
Customer accounts receivable, net	154	141
Other accounts receivable	68	42
Other allowance for credit losses	(9)	(4)
Other accounts receivable, net	59	38
Receivables from affiliates	1	—
Inventories, net		
Fossil fuel	6	8
Materials and supplies	51	44
Prepaid utility taxes	11	18
Regulatory assets	58	52
Renewable energy credits	10	9
Other	3	2
Total current assets	368	325
Property, plant, and equipment, (net of accumulated depreciation and amortization of $1,533 and $1,425 as of December 31, 2020 and 2019, respectively)	4,314	4,035
Deferred debits and other assets		
Regulatory assets	222	222
Goodwill	8	8
Prepaid pension asset	162	171
Other	66	69
Total deferred debits and other assets	458	470
Total assets	$ 5,140	$ 4,830

Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2020		December 31, 2019	
LIABILITIES AND SHAREHOLDER'S EQUITY				
Current liabilities				
Short-term borrowings	$	146	$	56
Long-term debt due within one year		82		80
Accounts payable		126		112
Accrued expenses		46		46
Payables to affiliates		36		32
Customer deposits		32		36
Regulatory liabilities		47		37
Other		20		15
Total current liabilities		535		414
Long-term debt		1,595		1,487
Deferred credits and other liabilities				
Deferred income taxes and unamortized investment tax credits		715		655
Asset retirement obligations		14		12
Non-pension postretirement benefit obligations		15		16
Regulatory liabilities		493		574
Other		97		92
Total deferred credits and other liabilities		1,334		1,349
Total liabilities		3,464		3,250
Commitments and contingencies				
Shareholder's equity				
Common stock ($2.25 par value, 0 shares[(a)] authorized, 0 shares[(a)] outstanding at December 31, 2020 and 2019, respectively)		1,089		977
Retained earnings		587		603
Total shareholder's equity		1,676		1,580
Total liabilities and shareholder's equity	$	5,140	$	4,830

(a) In millions, shares round to zero. Number of shares is 1,000 authorized and 1,000 outstanding at December 31, 2020 and 2019.

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 764	$ 571	$ 1,335
Net income	—	120	120
Common stock dividends	—	(96)	(96)
Contributions from parent	150	—	150
Balance, December 31, 2018	$ 914	$ 595	$ 1,509
Net income	—	147	147
Common stock dividends	—	(139)	(139)
Contributions from parent	63	—	63
Balance, December 31, 2019	$ 977	$ 603	$ 1,580
Net income	—	125	125
Common stock dividends	—	(141)	(141)
Contributions from parent	112	—	112
Balance, December 31, 2020	$ 1,089	$ 587	$ 1,676

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2020	2019	2018
Operating revenues			
Electric operating revenues	$ 1,253	$ 1,237	$ 1,237
Revenues from alternative revenue programs	(12)	—	(4)
Operating revenues from affiliates	4	3	3
Total operating revenues	1,245	1,240	1,236
Operating expenses			
Purchased power	596	589	587
Purchased power from affiliate	13	19	29
Operating and maintenance	192	187	188
Operating and maintenance from affiliates	134	133	142
Depreciation and amortization	180	157	136
Taxes other than income taxes	8	4	5
Total operating expenses	1,123	1,089	1,087
Gain on sale of assets	2	—	—
Operating income	124	151	149
Other income and (deductions)			
Interest expense, net	(59)	(58)	(64)
Other, net	6	6	2
Total other income and (deductions)	(53)	(52)	(62)
Income before income taxes	71	99	87
Income taxes	(41)	—	12
Net income	$ 112	$ 99	$ 75
Comprehensive income	$ 112	$ 99	$ 75

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2020	2019	2018
Cash flows from operating activities			
Net income	$ 112	$ 99	$ 75
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	180	157	136
Deferred income taxes and amortization of investment tax credits	(37)	3	25
Other non-cash operating activities	36	22	24
Changes in assets and liabilities:			
Accounts receivable	(55)	(13)	(8)
Receivables from and payables to affiliates, net	6	(6)	1
Inventories	(3)	(1)	(4)
Accounts payable and accrued expenses	5	26	(7)
Income taxes	(1)	2	(2)
Pension and non-pension postretirement benefit contributions	(2)	(1)	(6)
Other assets and liabilities	(42)	(27)	(6)
Net cash flows provided by operating activities	199	261	228
Cash flows from investing activities			
Capital expenditures	(401)	(375)	(335)
Other investing activities	6	(1)	1
Net cash flows used in investing activities	(395)	(376)	(334)
Cash flows from financing activities			
Change in short-term borrowings	117	56	(94)
Proceeds from short-term borrowings with maturities greater than 90 days	—	—	125
Repayments of short-term borrowings with maturities greater than 90 days	—	(125)	—
Issuance of long-term debt	123	150	350
Retirement of long-term debt	(44)	(18)	(281)
Dividends paid on common stock	(114)	(124)	(59)
Contributions from parent	117	175	67
Other financing activities	(1)	(1)	(3)
Net cash flows provided by financing activities	198	113	105
Increase (decrease) in cash, restricted cash, and cash equivalents	2	(2)	(1)
Cash, restricted cash, and cash equivalents at beginning of period	28	30	31
Cash, restricted cash, and cash equivalents at end of period	$ 30	$ 28	$ 30
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 33	$ (29)	$ 46

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 17	$ 12
Restricted cash and cash equivalents	3	2
Accounts receivable		
Customer accounts receivable	156	121
Customer allowance for credit losses	(32)	(13)
Customer accounts receivable, net	124	108
Other accounts receivable	72	53
Other allowance for credit losses	(11)	(5)
Other accounts receivable, net	61	48
Receivables from affiliates	6	4
Inventories, net	37	34
Regulatory assets	75	57
Other	3	5
Total current assets	326	270
Property, plant, and equipment, (net of accumulated depreciation and amortization of $1,303 and $1,210 as of December 31, 2020 and 2019, respectively)	3,475	3,190
Deferred debits and other assets		
Regulatory assets	395	368
Prepaid pension asset	40	52
Other	50	53
Total deferred debits and other assets	485	473
Total assets[a]	$ 4,286	$ 3,933

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 187	$ 70
Long-term debt due within one year	261	20
Accounts payable	177	144
Accrued expenses	46	42
Payables to affiliates	31	25
Customer deposits	23	25
Regulatory liabilities	44	25
Other	11	9
Total current liabilities	780	360
Long-term debt	1,152	1,307
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	624	577
Non-pension postretirement benefit obligations	17	17
Regulatory liabilities	274	357
Other	48	39
Total deferred credits and other liabilities	963	990
Total liabilities[(a)]	2,895	2,657
Commitments and contingencies		
Shareholder's equity		
Common stock ($3 par value, 25 shares authorized, 9 shares outstanding at December 31, 2020 and 2019)	1,271	1,154
Retained earnings	120	122
Total shareholder's equity	1,391	1,276
Total liabilities and shareholder's equity	$ 4,286	$ 3,933

(a) ACE's consolidated assets include $13 million and $17 million at December 31, 2020 and 2019, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated liabilities include $21 million and $41 million at December 31, 2020 and 2019, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 23 - Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 912	$ 131	$ 1,043
Net income	—	75	75
Common stock dividends	—	(59)	(59)
Contributions from parent	67	—	67
Balance, December 31, 2018	$ 979	$ 147	$ 1,126
Net income	—	99	99
Common stock dividends	—	(124)	(124)
Contributions from parent	175	—	175
Balance, December 31, 2019	$ 1,154	$ 122	$ 1,276
Net income	—	112	112
Common stock dividends	—	(114)	(114)
Contributions from parent	117	—	117
Balance, December 31, 2020	$ 1,271	$ 120	$ 1,391

See the Combined Notes to Consolidated Financial Statements

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

1. Significant Accounting Policies (All Registrants)

Description of Business (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	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments Pepco, DPL, and ACE	Service Territories of Pepco, DPL, and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland.
	Transmission and distribution of electricity to retail customers	
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	

Basis of Presentation (All Registrants)

This is a combined annual report of all Registrants. The Notes to the Consolidated Financial Statements apply to the Registrants as indicated parenthetically next to each corresponding disclosure. When appropriate, the Registrants are named specifically for their related activities and disclosures. Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology, and supply management services. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, accounting, engineering, customer operations, distribution and transmission planning, asset management, system operations, and power procurement, to PHI operating companies. The costs of BSC and PHISCO are directly charged or allocated to the applicable subsidiaries. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of Generation, PECO, BGE, and PHI and more than 99% of ComEd. PHI owns 100% of Pepco, DPL, and ACE. Generation owns 100% of its significant consolidated subsidiaries, either directly or indirectly, except for certain consolidated VIEs, including CENG and EGRP, of which Generation holds a 50.01% and 51% interest, respectively. The remaining interests in these consolidated VIEs are included in noncontrolling interests on Exelon's and Generation's Consolidated Balance Sheets. See Note 23 — Variable Interest Entities for additional information of Exelon's and Generation's consolidated VIEs.

The Registrants consolidate the accounts of entities in which a Registrant has a controlling financial interest, after the elimination of intercompany transactions. Where the Registrants do not have a controlling financial interest in an entity, proportionate consolidation, equity method accounting, or accounting for investments in equity securities with or without readily determinable fair value is applied. The Registrants apply proportionate consolidation when they have an undivided interest in an asset and are proportionately liable for their share of each liability associated with the asset. The Registrants proportionately consolidate their undivided ownership interests in jointly owned electric plants and transmission facilities. Under proportionate consolidation, the Registrants separately record their proportionate share of the assets, liabilities, revenues, and expenses related to the undivided interest in the asset. The Registrants apply equity method accounting when they have significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. The Registrants apply equity method accounting to certain investments and joint ventures. Under equity method accounting, the Registrants report their interest in the entity as an investment and the Registrants' percentage share of the earnings from the entity as single line items in their financial statements. The Registrants use accounting for investments in equity securities with or without readily determinable fair values if they lack significant influence, which generally results when they hold less than 20% of the common stock of an entity. Under accounting for investments in equity securities with readily determinable fair values, the Registrants report their investment values based on quoted prices in active markets and realized and unrealized gains and losses are included in earnings. Under accounting for investments in equity securities without readily determinable fair values, the Registrants report their investments at cost adjusted for changes from observable transactions for identical or similar investments of the same issuer, less impairment, and changes in measurement are reported in earnings.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

COVID-19 (All Registrants)

The Registrants have taken steps to mitigate the potential risks posed by the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19). 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. Management assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, the Registrants' allowance for credit losses and the carrying value of goodwill and other long-lived assets, in context with the information reasonably available to the Registrants and the unknown future impacts of COVID-19 as of December 31, 2020 and through the date of this report. The Registrants' future assessment of their current expectations of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts to their consolidated financial statements in future reporting periods.

Use of Estimates (All Registrants)

The preparation of financial statements of each of the Registrants in conformity with 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 nuclear decommissioning costs and other AROs, pension and OPEB, inventory reserves, allowance for credit losses, goodwill and asset impairment assessments, derivative instruments, unamortized energy contracts, 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 (Exelon and the Utility Registrants)

For their regulated electric and gas operations, Exelon and the Utility Registrants reflect the effects of cost-based rate regulation in their financial statements, which is required for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. Exelon and the Utility Registrants account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, PAPUC, MDPSC, DCPSC, DPSC, and NJBPU, 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 Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon'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 the Registrants' business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their financial statements. See Note 3 — Regulatory Matters for additional information.

With the exception of income tax-related regulatory assets and liabilities, Exelon and the Utility Registrants classify regulatory assets and liabilities with a recovery or settlement period greater than one year as both current and non-current in their Consolidated Balance Sheets, with the current portion representing the amount expected to be recovered from or refunded to customers over the next twelve-month period as of the balance sheet date. Income tax-related regulatory assets and liabilities are classified entirely as non-current in Exelon's and the Utility Registrants' Consolidated Balance Sheets to align with the classification of the related deferred income tax balances.

Exelon and the Utility Registrants treat 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 (All Registrants)

Operating Revenues. The Registrants' 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 ARP, and realized and unrealized revenues recognized under mark-to-market energy commodity derivative contracts. The Registrants recognize 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. 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 natural gas tariff sales, distribution, and transmission services. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco, and DPL record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC and/or DCPSC in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL, and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in accordance with their formula rate mechanisms. See Note 3 — 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 a Utility Registrant 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 3 — Regulatory Matters and Note 16 — Derivative Financial Instruments for additional information.

Taxes Directly Imposed on Revenue-Producing Transactions. The Registrants collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees, that are levied by state or local governments on the sale or distribution of electricity and gas. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, 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 24 — Supplemental Financial Information for Generation’s and the Utility Registrants' utility taxes that are presented on a gross basis.

Leases (All Registrants)

The Registrants adopted new accounting guidance issued by the FASB related to leases as of January 1, 2019. The Registrants recognize a ROU asset and lease liability for operating and finance leases with a term of greater than one year. Operating lease ROU assets are included in Other deferred debits and other assets and operating lease liabilities are included in Other current liabilities and Other deferred credits and other liabilities on the Consolidated Balance Sheets. Finance lease ROU assets are included in Plant, property, and equipment, net and finance lease liabilities are included in Long-term debt due within one year and Long-term debt on the Consolidated Balance Sheets. The ROU asset is measured as the sum of (1) the present value of all remaining fixed and in-substance fixed payments using each Registrant’s incremental borrowing rate, (2) any lease payments made at or before the commencement date (less any lease incentives received), and (3) any initial direct costs incurred. The lease liability is measured the same as the ROU asset, but excludes any payments made before the commencement date and initial direct costs incurred. Lease terms include options to extend or terminate the lease if it is reasonably certain they will be exercised. The Registrants include non-lease components for most asset classes, which are service-related costs that are not integral to the use of the asset, in the measurement of the ROU asset and lease liability.

Expense for operating leases and leases with a term of one year or less is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the derivation of benefit from use of the leased property. Variable lease payments are recognized in the period in which the related obligation is incurred and consist primarily of payments for purchases of electricity under contracted generation and are based on the electricity produced by those generating assets. Operating lease expense and variable lease payments are recorded to Purchased power and fuel expense for contracted generation or Operating and maintenance expense for all other lease agreements on the Registrants’ Statements of Operations and Comprehensive Income. Expense for finance leases is primarily recorded to Operating and maintenance on the Utility Registrants’ Statements of Operations and Comprehensive Income.

Income from operating leases, including subleases, is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the pattern in which income is earned over the term of the lease. Variable lease payments are recognized in the period in which the related obligation is performed and consist primarily of payments received from sales of electricity under contracted generation and are based on the electricity produced by those generating assets. Operating lease income and variable lease payments are recorded to Operating revenues on the Registrants’ Statements of Operations and Comprehensive Income.

The Registrants’ operating and finance leases consist primarily of contracted generation, real estate including office buildings, and vehicles and equipment. The Registrants generally account for contracted generation in which the generating asset is not renewable as a lease if the customer has dispatch rights and obtains substantially all of the economic benefits. For new agreements entered after January 1, 2019, the Registrants generally do not account for contracted generation in which the generating asset is renewable as a lease if the customer does not design the generating asset. The Registrants account for land right arrangements that provide for exclusive use as leases while shared use land arrangements are generally not leases. The Registrants do not account for secondary use pole attachments as leases.

See Note 11 — Leases for additional information.

Income Taxes (All Registrants)

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 the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. The Registrants account 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. The Registrants recognize accrued interest related to unrecognized tax benefits in Interest expense, net or Other, net (interest income) and recognize penalties related to unrecognized tax benefits in Other, net in their Consolidated Statements of Operations and Comprehensive Income.

Cash and Cash Equivalents (All Registrants)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents (All Registrants)

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2020 and 2019, the Registrants' restricted cash and cash equivalents primarily represented the following items:

Registrant	Description
Exelon	Payment of medical, dental, vision, and long-term disability benefits, in addition to the items listed for Generation and the Utility Registrants.
Generation	Project-specific nonrecourse financing structures for debt service and financing of operations of the underlying entities.
ComEd	Collateral held from suppliers associated with energy and REC procurement contracts, any over-recovered RPS costs and alternative compliance payments received from RES pursuant to FEJA, and costs for the remediation of an MGP site.
PECO	Proceeds from the sales of assets that were subject to PECO's mortgage indenture.
BGE	Proceeds from the loan program for the completion of certain energy efficiency measures and collateral held from energy suppliers.
PHI	Payment of merger commitments, collateral held from its energy suppliers associated with procurement contracts, and repayment of Transition Bonds.
Pepco	Payment of merger commitments and collateral held from energy suppliers.
DPL	Collateral held from energy suppliers.
ACE	Repayment of Transition Bonds and collateral held from energy suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2020 and 2019, the Registrants' noncurrent restricted cash and cash equivalents primarily represented ComEd's over-recovered RPS costs and alternative compliance payments received from RES pursuant to FEJA and costs for the remediation of an MGP site, and ACE's repayment of Transition Bonds.

See Note 24 — Supplemental Financial Information for additional information.

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 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 or Regulatory assets and liabilities on the Utility Registrants' Consolidated Balance Sheets. See Note 3 - Regulatory Matters for additional information regarding the regulatory recovery of credit losses on customer accounts receivable.

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 not material. The Registrants monitor these balances and will record an allowance if there are indicators of a decline in credit quality.

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

Exelon accounts for its investments in and arrangements with VIEs based on the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity has a controlling financial interest,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to disclose (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

See Note 23 — Variable Interest Entities for additional information.

Inventories (All Registrants)

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

Debt and Equity Security Investments (Exelon and Generation)

Debt Security Investments. Debt securities are reported at fair value and classified as available-for-sale securities. Unrealized gains and losses, net of tax, are reported in OCI.

Equity Security Investments without Readily Determinable Fair Values. Exelon has certain equity securities without readily determinable fair values. Exelon has elected to use the practicability exception to measure these investments, defined as cost adjusted for changes from observable transactions for identical or similar investments of the same issuer, less impairment. Changes in measurement are reported in earnings.

Equity Security Investments with Readily Determinable Fair Values. Exelon has certain equity securities with readily determinable fair values. For equity securities held in NDT funds, realized and unrealized gains and losses, net of tax, on Generation’s NDT funds associated with the Regulatory Agreement Units are included in regulatory liabilities at Exelon, ComEd, and PECO, in Noncurrent payables to affiliates at Generation and in

Noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation’s NDT funds associated with the Non-Regulatory Agreement Units are included in earnings at Exelon and Generation. Exelon's and Generation's NDT funds are classified as current or noncurrent assets, depending on the timing of the decommissioning activities and income taxes on trust earnings. For all other equity securities with readily determinable fair values, realized and unrealized gains and losses are included in earnings at Exelon and Generation. See Note 3 — Regulatory Matters for additional information regarding ComEd’s and PECO’s regulatory assets and liabilities and Note 18 — Fair Value of Financial Assets and Liabilities and Note 10 — Asset Retirement Obligations for additional information.

Property, Plant, and Equipment (All Registrants)

Property, plant, and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. The Utility Registrants also include indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes capitalized interest for Generation, Exelon Corporate, and PHI and AFUDC for regulated property at the Utility Registrants. 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 the Utility Registrants 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 the Utility Registrants have been accounted for as CIAC.

For Generation, upon retirement, the cost of property is generally charged to accumulated depreciation in accordance with the composite and group methods of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to Operating and maintenance expense as incurred.

For the Utility Registrants, 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 ComEd, BGE, Pepco, DPL, and ACE 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. PECO’s removal costs are capitalized to accumulated depreciation when incurred and recorded to depreciation expense over the life of the new asset constructed consistent with PECO’s regulatory recovery method.

Capitalized Software. Certain costs, such as design, coding, and testing incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized within Property, plant, and equipment. Similar costs incurred for cloud-based solutions treated as service arrangements are capitalized within Other Current Assets and Deferred Debits and Other Assets. 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.

Capitalized Interest and AFUDC. During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

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 8 — Property, Plant, and Equipment, Note 9 — Jointly Owned Electric Utility Plant and Note 24 — Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within Property, plant, and equipment and charged to fuel expense using the unit-of-production method. Any potential future SNF disposal fees will be expensed through fuel expense. Additionally, certain on-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 19 — Commitments and Contingencies for additional information regarding the cost of SNF storage and disposal.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to Operating and maintenance expense or capitalized to Property, plant, and equipment (based on the nature of the activities) in the period incurred.

Depreciation and Amortization (All Registrants)

Except for the amortization of nuclear fuel, 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. ComEd, BGE, Pepco, DPL, and ACE's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method. The estimated service lives for the Registrants 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 7 — Early Plant Retirements for additional information on the impacts of early plant retirements.

See Note 8 — Property, Plant, and Equipment for additional 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 the Utility Registrants’ Consolidated Statements of Operations and Comprehensive Income. Amortization of ComEd’s electric distribution and energy efficiency formula rate regulatory assets and the Utility Registrants' 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 the Registrants’ Consolidated Statements of Operations and Comprehensive Income.

See Note 3 — Regulatory Matters and Note 24 — Supplemental Financial Information for additional information regarding Generation’s nuclear fuel and ARC, and the amortization of the Utility Registrants' regulatory assets.

Asset Retirement Obligations (All Registrants)

Generation estimates and recognizes a liability for its legal obligation to perform asset retirement activities even though the timing and/or methods of settlement may be conditional on future events. Generation generally updates its nuclear decommissioning ARO annually, unless circumstances warrant more frequent updates, based on its annual evaluation of cost escalation factors and probabilities assigned to the multiple outcome scenarios within its probability-weighted discounted cash flow models. Generation’s multiple outcome scenarios are generally based on decommissioning cost studies which are updated, on a rotational basis, for each of Generation’s nuclear units at least every five years, unless circumstances warrant more frequent updates. 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 Consolidated Statements of Operations and Comprehensive Income for Non-Regulatory Agreement Units and through a decrease to regulatory liabilities for Regulatory Agreement Units or, in the case of the Utility Registrants' accretion, through an increase to regulatory assets. See Note 10 — Asset Retirement Obligations for additional information.

Guarantees (All Registrants)

If necessary, the Registrants recognize a liability at the time of issuance of a guarantee for the fair market value of the obligations they have undertaken by issuing the guarantee. The liability is reduced or eliminated as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant 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 19 — Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets (All Registrants). The Registrants 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. The Registrants determine 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. See Note 12 — Asset Impairments for additional information.

Goodwill (Exelon, ComEd, and PHI). Goodwill represents the excess of the purchase price paid over the estimated fair value of the net assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is assessed for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 13 — Intangible Assets for additional information.

Equity Method Investments (Exelon and Generation). Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature. Additionally, if the entity in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other-than-temporary decline in value.

Debt Security Investments (Exelon and Generation). Declines in the fair value of debt security investments below the cost basis are reviewed to determine if such declines are other-than-temporary. If the decline is determined to be other-than-temporary, the amount of the impairment loss is included in earnings.

Equity Security Investments (Exelon and Generation). Equity investments with readily determinable fair values are measured and recorded at fair value with any changes in fair value recorded through earnings. Investments in equity securities without readily determinable fair values are qualitatively assessed for impairment each reporting period. If it is determined that the equity security is impaired on the basis of the qualitative assessment, an impairment loss will be recognized in earnings to the amount by which the security's carrying amount exceeds its fair value.

Derivative Financial Instruments (All Registrants)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the NPNS. For derivatives intended to serve as economic hedges, changes in fair value are recognized in earnings each period. Amounts classified in earnings are included in Operating revenue, Purchased power and fuel, Interest expense, or Other, net in the Consolidated Statements of Operations and Comprehensive Income based on the activity the transaction is economically hedging. While the majority of the derivatives serve as economic hedges, there are also derivatives entered into for proprietary trading purposes, subject to Exelon's Risk Management Policy, and changes in the fair value of those derivatives are recorded in revenue in the Consolidated Statements of Operations and Comprehensive Income. At the Utility Registrants, 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 Consolidated Statements of Cash Flows, depending on the nature of each transaction. On July 1, 2018, Exelon and Generation de-designated its fair value and cash flow hedges. See Note 3 — Regulatory Matters and Note 16 — Derivative Financial Instruments for additional information.

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. NPNS are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as NPNS are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 16 — Derivative Financial Instruments for additional information.

Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and OPEB plans for essentially all current employees.

The plan obligations and costs of providing benefits under these plans are measured as of December 31. The measurement involves various factors, assumptions, and accounting elections. The impact of assumption changes or experience different from that assumed on pension and OPEB obligations is recognized over time rather than immediately recognized in the Consolidated Statements of Operations and Comprehensive 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 15 — Retirement Benefits for additional information.

New Accounting Standards (All Registrants)

New Accounting Standards Adopted in 2020: In 2020, the Registrants adopted the following new authoritative accounting guidance issued by the FASB.

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' trade accounts receivables balances. The 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 impairment assessment model, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment assessment). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment assessment is necessary. The standard was effective January 1, 2020 and must be applied on a prospective basis. Exelon, ComEd, and PHI adopted the new guidance in 2020. The new guidance did not impact Exelon's, ComEd's, and PHI's 2020 annual goodwill impairment assessments as they performed a qualitative assessment.

2. Mergers, Acquisitions, and Dispositions (Exelon and Generation)

CENG Put Option (Exelon and Generation)

Generation owns a 50.01% membership interest in CENG, a joint venture with EDF, which wholly owns the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to an 82% undivided ownership interest in Nine Mile Point Unit 2. CENG is 100% consolidated in Exelon's and Generation's financial statements. See Note 23 — Variable Interest Entities for additional information.

On April 1, 2014, Generation and EDF entered into various agreements including a NOSA, an amended LLC Operating Agreement, an Employee Matters Agreement, and a Put Option Agreement, among others. Under the amended LLC Operating Agreement, CENG made a $400 million special distribution to EDF and committed to make preferred distributions to Generation until Generation has received aggregate distributions of $400 million plus a return of 8.50% per annum. Under the Put Option Agreement, EDF has the option to sell its 49.99% equity interest in CENG to Generation exercisable beginning on January 1, 2016 and thereafter until June 30, 2022. 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.

Under the terms of the Put Option Agreement, the purchase price is to be determined by agreement of the parties, or absent such agreement, by a third-party arbitration process. The third parties determining fair market value of EDF's 49.99% interest are to take into consideration all rights and obligations under the LLC Operating Agreement and Employee Matters Agreement including but not limited to Generation's rights with respect to any unpaid aggregate preferred distributions and the related return. As of December 31, 2020, the total unpaid aggregate preferred distributions and related return owed to Generation is $619 million. 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 and the FERC. The FERC approval was obtained on July 30, 2020. The process and regulatory approvals are expected to close in the second half of 2021.

Agreement for Sale of Generation's Solar Business (Exelon and Generation)

On December 8, 2020, Generation entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of Generation's solar business, including 360 megawatts of generation in operation or under construction across more than 600 sites across the United States. Under the terms of the transaction, the purchase price is $810 million, subject to certain working capital and other post-closing adjustments. Generation will retain certain solar assets not included in this agreement, primarily Antelope Valley.

As a result of the transaction, in the fourth quarter of 2020, Exelon and Generation reclassified the solar assets and liabilities on Exelon's and Generation's Consolidated Balance Sheets as held for sale. The transaction is expected to result in an estimated pre-tax gain ranging from $75 million to $125 million. The gain will be recorded in Gain on sales of assets and businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income upon completion of the transaction. Completion of the transaction contemplated by the sale agreement is subject to the satisfaction of several closing conditions and is expected to occur in the first half of 2021. See Note 17 — Debt and Credit Agreements for additional information on the SolGen nonrecourse debt included as part of the transaction.

Disposition of Oyster Creek (Exelon and Generation)

On July 31, 2018, Generation entered into an agreement with Holtec and its indirect wholly owned subsidiary, OCEP, for the sale and decommissioning of Oyster Creek located in Forked River, New Jersey, which permanently ceased generation operations on September 17, 2018. Completion of the transaction contemplated by the sale agreement was subject to the satisfaction of several closing conditions, including approval of the license transfer from the NRC and other regulatory approvals, and a private letter ruling from the IRS, which were satisfied in the second quarter 2019. The sale was completed on July 1, 2019. Exelon and Generation recognized a loss on the sale in the third quarter of 2019, which was immaterial.

Under the terms of the transaction, Generation transferred to OCEP substantially all the assets associated with Oyster Creek, including assets held in NDT funds, along with the assumption of liability for all responsibility for the site, including full decommissioning and ongoing management of spent fuel until the spent fuel is moved offsite. The terms of the transaction also include various forms of performance assurance for the obligations of OCEP to timely complete the required decommissioning, including a parental guaranty from Holtec for all performance and payment obligations of OCEP, and a requirement for Holtec to deliver a letter of credit to Generation upon the occurrence of specified events.

Upon remeasurement of the Oyster Creek ARO, Exelon and Generation recognized an $84 million and a $9 million pre-tax charge to Operating and maintenance expense in 2018 and in 2019, respectively. See Note 10 — Asset Retirement Obligations for additional information.

Disposition of Electrical Contracting Business (Exelon and Generation)

On February 28, 2018, Generation completed the sale of its interest in an electrical contracting business that primarily installs, maintains, and repairs underground and high-voltage cable transmission and distribution systems for $87 million, resulting in a pre-tax gain which is included within Gain on sales of assets and businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2018.

3. Regulatory Matters (All Registrants)

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

Utility Regulatory Matters (Exelon, PHI, and the Utility Registrants)

Distribution Base Rate Case Proceedings

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

Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois(a)	April 8, 2019	Electric	$ (6)	$ (17)	8.91 %	December 4, 2019	January 1, 2020
ComEd - Illinois(a)	April 16, 2020	Electric	(11)	(14)	8.38 %	December 9, 2020	January 1, 2021
BGE - Maryland(b)	May 15, 2020 (amended September 11, 2020)	Electric	137	81	9.50 %	December 16, 2020	January 1, 2021
		Natural Gas	91	21	9.65 %		
DPL - Maryland	December 5, 2019 (amended April 23, 2020)	Electric	17	12	9.60 %	July 14, 2020	July 16, 2020
DPL - Delaware	February 21, 2020 (amended October 9, 2020)	Natural Gas	7	2	9.60 %	January 6, 2021	September 21, 2020

(a) Pursuant to EIMA and FEJA, ComEd's electric distribution rates are established through a performance-based formula, which sunsets at the end of 2022. The electric distribution formula rate includes decoupling provisions and, as a result, ComEd's electric distribution formula rate revenues are not impacted by abnormal weather, usage per customer, or number of customers. ComEd is required to file an annual update to its electric distribution formula rate on or before May 1st, with resulting rates effective in January of the following year. ComEd's annual electric distribution 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 for the prior year and actual costs incurred from the year (annual reconciliation).

ComEd's 2020 approved revenue requirement above reflects an increase of $51 million for the initial year revenue requirement for 2020 and a decrease of $68 million related to the annual reconciliation for 2018. The revenue requirement for 2020 and the revenue requirement 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 monthly average yields for 30-year treasury bonds plus 580 basis points.

ComEd's 2021 approved revenue requirement above reflects an increase of $50 million for the initial year revenue requirement for 2021 and a decrease of $64 million related to the annual reconciliation for 2019. The revenue requirement for 2021 and the revenue requirement for 2019 provide for a weighted average debt and equity return on distribution rate base of 6.28% inclusive of an allowed ROE of 8.38%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points. See table below for ComEd's regulatory assets associated with its electric distribution formula rate.

(b) Reflects a three-year cumulative multi-year plan for 2021 through 2023. The MDPSC awarded BGE electric revenue requirement increases of $59 million, $39 million, and $42 million in 2021, 2022, and 2023, respectively, and natural gas revenue requirement increases of $53 million, $11 million, and $10 million in 2021, 2022, and 2023, respectively. However, the MDPSC utilized certain tax benefits to fully offset the increases in 2021 so that customer rates will remain unchanged from 2020 to 2021. The MDPSC has deferred a decision on whether to use certain tax benefits to offset the revenue requirement increases in 2022 and 2023 and BGE cannot predict the outcome.

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
PECO - Pennsylvania	September 30, 2020	Natural Gas	$ 69	10.95 %	Second quarter of 2021
Pepco - District of Columbia[(a)]	May 30, 2019 (amended June 1, 2020)	Electric	136	9.7 %	Second quarter of 2021
Pepco - Maryland[(b)]	October 26, 2020	Electric	110	10.2 %	Second quarter of 2021
DPL - Delaware[(c)]	March 6, 2020 (amended February 2, 2021)	Electric	23	10.3 %	Third quarter of 2021
ACE - New Jersey[(d)]	December 9, 2020	Electric	67	10.3 %	Fourth quarter of 2021

(a) Pepco filed the multi-year plan enhanced proposal as an alternative to address the impacts of COVID-19. Reflects a three-year cumulative multi-year plan for 2020 through 2022 and requested revenue requirement increases of $73 million in 2022 and $63 million in 2023, to recover capital investments made during 2018 through 2020 and planned capital investments through the end of 2022.
(b) Reflects a three-year cumulative multi-year plan for April 1, 2021 through March 31, 2024 and total requested revenue requirement increases of $56 million effective April 1, 2023 and $54 million effective April 1, 2024 to recover capital investments made in 2019 and 2020 and planned capital investments through March 31, 2024.
(c) The rates went into effect on October 6, 2020, subject to refund.
(d) Requested increases are before New Jersey sales and use tax. ACE intends to put rates into effect on September 8, 2021, subject to refund.

Transmission Formula Rates (Exelon, PHI, and the Utility Registrants)

The Utility Registrants' transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15, and PECO is required to file on or before May 31, with the resulting rates effective on June 1 of the same year. The annual update for ComEd, BGE, DPL, and ACE is based on prior year actual costs and current year projected capital additions (initial year revenue requirement). The annual update for PECO is based on prior year actual costs and current year projected capital additions, accumulated depreciation, and accumulated deferred income taxes. The annual update for Pepco is based on prior year actual costs and current year projected capital additions, accumulated depreciation, depreciation and amortization expense, and accumulated deferred income taxes. The update for ComEd, BGE, DPL, and ACE 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). The update for PECO and Pepco also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2020, the following total increases/(decreases) were included in the Utility Registrants' electric transmission formula rate updates:

Registrant(a)	Initial Revenue Requirement Increase/(Decrease)	Annual Reconciliation Decrease	Total Revenue Requirement Increase/(Decrease)(b)	Allowed Return on Rate Base(c)	Allowed ROE(d)
ComEd	$ 18	$ (4)	$ 14	8.17 %	11.50 %
PECO	5	(28)	(23)	7.47 %	10.35 %
BGE	16	(3)	4	7.26 %	10.50 %
Pepco	2	(46)	(44)	7.81 %	10.50 %
DPL	(4)	(40)	(44)	7.20 %	10.50 %
ACE	5	(25)	(20)	7.40 %	10.50 %

(a) All rates are effective June 30, 2020 - May 31, 2021, subject to review by interested parties pursuant to review protocols of each Utility Registrant's tariff.

(b) The decrease in PECO's transmission revenue requirement relates to refunds from December 1, 2017, in accordance with the settlement agreement dated July 22, 2019. The increase in BGE's transmission revenue requirement includes a $9 million reduction related to a FERC approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE. ComEd, BGE, Pepco, DPL, and ACE's transmission revenue requirement include a decrease related to the April 24, 2020 settlement agreement related to excess deferred income taxes. Refer to Transmission-Related Income Tax Regulatory assets below for additional information.

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

(d) As part of the FERC-approved settlement of ComEd's 2007 and PECO's 2017 transmission rate cases, the rate of return on common equity is 11.50% and 10.35%, respectively inclusive of a 50-basis-point incentive adder for being a member of a RTO, and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55% and 55.75%, respectively. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL, and ACE, 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

Illinois Regulatory Matters

Energy Efficiency Formula Rate (Exelon and ComEd). FEJA allows ComEd to defer energy efficiency costs (except for any voltage optimization costs which are recovered through the electric distribution formula rate) as a separate regulatory asset that is recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures. ComEd earns a return on the energy efficiency regulatory asset at a rate equal to its weighted average cost of capital, which is based on a year-end capital structure and calculated using the same methodology applicable to ComEd's electric distribution formula rate. Beginning January 1, 2018 through December 31, 2030, the ROE that ComEd earns on its energy efficiency regulatory asset is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. ComEd is required to file an update to its energy efficiency formula rate on or before June 1st each year, with resulting rates effective in January of the following year. The annual update is based on projected current year energy efficiency costs, PJM capacity revenues, and the projected year-end regulatory asset balance less any related deferred income taxes (initial year revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred from the year (annual reconciliation). The approved energy efficiency formula rate also provides for revenue decoupling provisions similar to those in ComEd's electric distribution formula rate.

During 2020, the ICC approved the following total increases in ComEd's requested energy efficiency revenue requirement:

Filing Date	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
May 21, 2020	$ 48	$ 48 (a)	8.38 %	December 2, 2020	January 1, 2021

(a) ComEd's 2021 approved revenue requirement above reflects an increase of $45 million for the initial year revenue requirement for 2021 and an increase of $3 million related to the annual reconciliation for 2019. The revenue requirement for 2021 provides for a weighted average debt and equity return on the energy efficiency regulatory asset and rate base of 6.28% inclusive of an allowed ROE of 8.38%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points. The revenue requirement for 2019 provides for a weighted average debt and equity return on the energy efficiency regulatory asset and rate base of 6.56% inclusive of an allowed ROE of 8.96%, which includes an upward performance adjustment that can either increase or decrease the ROE. See table below for ComEd's regulatory assets associated with its energy efficiency formula rate.

Maryland Regulatory Matters

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). On December 1, 2017 (as amended on January 22, 2018), BGE filed an application with the MDPSC seeking approval for a new gas infrastructure replacement plan and associated surcharge, effective for the five-year period from 2019 through 2023. On May 30, 2018, the MDPSC approved with modifications a new infrastructure plan and associated surcharge, subject to BGE's acceptance of the Order. On June 1, 2018, BGE accepted the MDPSC Order and the associated surcharge became effective January 2019. The five-year plan calls for capital expenditures over the 2019-2023 timeframe of $732 million with an associated revenue requirement of $200 million.

Cash Working Capital Order (Exelon and BGE). On November 17, 2016, the MDPSC rendered a decision in the proceeding to review BGE's request to recover its cash working capital (CWC) requirement for its POLR service, also known as SOS, as well as other components that make up the Administrative Charge, the mechanism that enables BGE to recover its SOS-related costs. The Administrative Charge is comprised of five components: CWC, uncollectibles, incremental costs, return, and an administrative adjustment, which acts as a proxy for retail suppliers' costs. The MDPSC accepted BGE's positions on recovery of CWC and pass-through recovery of BGE's actual uncollectibles and incremental costs. The order also grants BGE a return on the SOS. Subsequently, the MDPSC Staff and residential consumer advocate sought clarification and appealed the amount of return awarded to BGE on the SOS. On July 27, 2020, the Maryland Court of Special Appeals affirmed the circuit court's judgment affirming the MDPSC's decision. No party appealed the decision to the Maryland Court of Appeals. Also, in BGE's 2019 electric and gas distribution base rate proceeding, the MDPSC established a normalized administrative adjustment. However, a group of electric suppliers appealed the MDPSC's decision to the Circuit Court for Baltimore City. BGE cannot predict the outcome of this appeal.

New Jersey Regulatory Matters

ACE Infrastructure Investment Program Filing (Exelon, PHI, and ACE). On February 28, 2018, ACE filed with the NJBPU the company's IIP proposing to seek recovery of a series of investments through a new rider mechanism, totaling $338 million, between 2019-2022 to provide safe and reliable service for its customers. The IIP will allow for more timely recovery of investments made to modernize and enhance ACE's electric system. On April 15, 2019, ACE entered into a settlement agreement with other parties, which allows for a recovery totaling $96 million of reliability related capital investments from July 1, 2019 through June 30, 2023. On April 18, 2019, the NJBPU approved the settlement agreement.

Advanced Metering Infrastructure Filing (Exelon, PHI, and ACE). On August 26, 2020, ACE filed an application with the NJBPU as was required seeking approval to deploy a smart energy network in alignment with New Jersey's Energy Master Plan and Clean Energy Act. The proposal consists of estimated costs totaling $220 million, with deployment taking place over a 3-year implementation period from approximately 2021 to 2024 that involves the installation of an integrated system of smart meters for all customers accompanied by the requisite communications facilities and data management systems. ACE is seeking authority to recover these estimated investments through a combination of the ACE IIP rider mechanism and future distribution base rates. ACE currently expects a decision in this matter in the third quarter of 2021 but cannot predict if the NJBPU will approve the application as filed.

New Jersey Clean Energy Legislation (Exelon, PHI, and ACE). On May 23, 2018, New Jersey enacted legislation that established and modified New Jersey's clean energy and energy efficiency programs and solar and RPS. On the same day, 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. Electric distribution utilities in New Jersey, including ACE, began collecting from retail distribution customers, through a non-bypassable charge, all costs associated with the utility's procurement of the ZECs effective April 18, 2019. See Generation Regulatory Matters below for additional information.

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 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 assets for the portion of the income tax regulatory assets that would have been previously amortized.

On February 23, 2018 (as amended on July 9, 2018), 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) the 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 U.S. Court of Appeals for the D.C. Circuit. On March 27, 2020, the U.S. Court of Appeals for the D.C. Circuit Court denied BGE's November 2, 2018 appeal.

On October 1, 2018, ComEd, BGE, Pepco, DPL, and ACE submitted filings to recover 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, which FERC approved on September 24, 2020. The settlement agreement provides for the recovery of ongoing transmission-related income tax regulatory assets and establishes the amount and amortization period for excess deferred income taxes resulting from TCJA. The settlement resulted in a reduction to Operating revenues and an offsetting reduction to Income tax expense in the second quarter of 2020.

Regulatory Assets and Liabilities

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

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE as of December 31, 2020 and December 31, 2019:

December 31, 2020	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Regulatory assets								
Pension and OPEB	$ 3,010	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Pension and OPEB - merger related	1,014	—	—	—	—	—	—	—
Deferred income taxes	715	—	705	—	10	10	—	—
AMI programs - deployment costs	174	—	—	109	65	35	30	—
AMI programs - legacy meters	219	90	—	37	92	68	24	—
Electric distribution formula rate annual reconciliations	(14)	(14)	—	—	—	—	—	—
Electric distribution formula rate significant one-time events	117	117	—	—	—	—	—	—
Energy efficiency costs	982	982	—	—	—	—	—	—
Fair value of long-term debt	598	—	—	—	478	—	—	—
Fair value of PHI's unamortized energy contracts	328	—	—	—	328	—	—	—
Asset retirement obligations	135	92	21	18	4	3	—	1
MGP remediation costs	285	271	10	4	—	—	—	—
Renewable energy	301	301	—	—	—	—	—	—
Electric energy and natural gas costs	95	—	—	23	72	37	5	30
Transmission formula rate annual reconciliations	5	—	—	2	3	—	2	1
Energy efficiency and demand response programs	572	—	—	289	283	203	80	—
Under-recovered revenue decoupling	113	—	—	20	93	93	—	—
Stranded costs	25	—	—	—	25	—	—	25
Removal costs	701	—	—	107	594	151	105	339
DC PLUG charge	100	—	—	—	100	100	—	—
Deferred storm costs	50	—	—	—	50	5	4	41
COVID-19	81	22	38	10	11	7	4	—
Under-recovered credit loss expense	107	89	—	—	18	—	—	18
Other	274	78	27	30	147	72	26	15
Total regulatory assets	9,987	2,028	801	649	2,373	784	280	470
Less: current portion	1,228	279	25	168	440	214	58	75
Total noncurrent regulatory assets	$ 8,759	$ 1,749	$ 776	$ 481	$ 1,933	$ 570	$ 222	$ 395

December 31, 2020	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Deferred income taxes	$ 4,502	$ 2,205	$ —	$ 1,001	$ 1,296	$ 621	$ 404	$ 271
Nuclear decommissioning	3,016	2,541	475	—	—	—	—	—
Removal costs	1,649	1,482	—	47	120	20	100	—
Electric energy and natural gas costs	175	34	97	6	38	24	10	4
Transmission formula rate annual reconciliations	52	2	12	—	38	23	9	6
Renewable portfolio standards costs	427	427	—	—	—	—	—	—
Stranded costs	24	—	—	—	24	—	—	24
Other	221	1	40	85	59	2	17	13
Total regulatory liabilities	10,066	6,692	624	1,139	1,575	690	540	318
Less: current portion	581	289	121	30	137	46	47	44
Total noncurrent regulatory liabilities	$ 9,485	$ 6,403	$ 503	$ 1,109	$ 1,438	$ 644	$ 493	$ 274

December 31, 2019 **Regulatory assets**	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Pension and OPEB	$ 2,784	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Pension and OPEB - merger related	1,138	—	—	—	—	—	—	—
Deferred income taxes	528	—	518	—	10	10	—	—
AMI programs - deployment costs	207	—	—	129	78	43	35	—
AMI programs - legacy meters	276	113	12	45	106	79	27	—
Electric distribution formula rate annual reconciliations	34	34	—	—	—	—	—	—
Electric distribution formula rate significant one-time events	66	66	—	—	—	—	—	—
Energy efficiency costs	746	746	—	—	—	—	—	—
Fair value of long-term debt	650	—	—	—	523	—	—	—
Fair value of PHI's unamortized energy contracts	443	—	—	—	443	—	—	—
Asset retirement obligations	127	85	23	16	3	2	—	1
MGP remediation costs	302	287	11	4	—	—	—	—
Renewable energy	301	301	—	—	—	—	—	—
Electric energy and natural gas costs	110	—	6	36	68	43	5	20
Transmission formula rate annual reconciliations	11	—	—	1	10	1	2	7
Energy efficiency and demand response programs	572	—	—	303	269	196	73	—
Merger integration costs	32	—	—	2	30	15	8	7
Under-recovered revenue decoupling	37	—	—	8	29	29	—	—
Stranded costs	37	—	—	—	37	—	—	37
Removal costs	641	—	—	67	574	152	100	324
DC PLUG charge	126	—	—	—	126	126	—	—
Other	337	129	25	26	167	76	24	29
Total regulatory assets	9,505	1,761	595	637	2,473	772	274	425
Less: current portion	1,170	281	41	183	412	188	52	57
Total noncurrent regulatory assets	$ 8,335	$ 1,480	$ 554	$ 454	$ 2,061	$ 584	$ 222	$ 368

December 31, 2019 **Regulatory liabilities**	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Deferred income taxes	$ 4,944	$ 2,297	$ —	$ 1,089	$ 1,558	$ 725	$ 477	$ 356
Nuclear decommissioning	3,102	2,622	480	—	—	—	—	—
Removal costs	1,621	1,435	—	58	128	20	108	—
Electric energy and natural gas costs	109	45	56	—	8	—	8	—
Transmission formula rate annual reconciliations	34	6	28	—	—	—	—	—
Other	582	337	37	81	83	9	18	26
Total regulatory liabilities	10,392	6,742	601	1,228	1,777	754	611	382
Less: current portion	406	200	91	33	70	8	37	25
Total noncurrent regulatory liabilities	$ 9,986	$ 6,542	$ 510	$ 1,195	$ 1,707	$ 746	$ 574	$ 357

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
Pension and OPEB	Primarily reflects the Utility Registrants' portion of deferred costs, including unamortized actuarial losses (gains) and prior service costs (credits), associated with Exelon's pension and OPEB plans, which are recovered through customer rates once amortized through net periodic benefit cost. Also, includes the Utility Registrants' non–service cost components capitalized in Property, plant and equipment, net on their Consolidated Balance Sheets.	The deferred costs are amortized over the plan participants' average remaining service periods subject to applicable pension and OPEB cost recognition policies. See Note 15 — Retirement Benefits for additional information. The capitalized non–service cost components are amortized over the lives of the underlying assets.	No
Pension and OPEB - merger related	The deferred costs are amortized over the plan participants' average remaining service periods subject to applicable pension and OPEB cost recognition policies. See Note 15 — Retirement Benefits for additional information. The capitalized non–service cost components are amortized over the lives of the underlying assets.	Legacy Constellation - 2038 Legacy PHI - 2032	No
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

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
AMI programs - deployment costs	Installation costs of new smart meters, including implementation costs at Pepco and DPL of dynamic pricing for energy usage resulting from smart meters.	BGE - 2026 Pepco - 2027 DPL - 2030	Yes
AMI programs - legacy meters	Early retirement costs of legacy meters.	ComEd - 2028 BGE - 2026 Pepco - 2027 DPL - 2030	ComEd, Pepco (District of Columbia), DPL (Delaware) - Yes BGE, Pepco (Maryland), DPL (Maryland) - No
Electric distribution formula rate annual reconciliations	Under/(Over)-recoveries related to electric distribution service costs recoverable through ComEd's performance-based formula rate, which is updated annually with rates effective on January 1st.	2022	Yes
Electric distribution formula rate significant one-time events	Deferred distribution service costs related to ComEd's significant one-time events (e.g., storm costs), which are recovered over 5 years from date of the event.	2024	Yes
Energy efficiency costs	ComEd's costs recovered through the energy efficiency formula rate tariff and the reconciliation of the difference of the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs. Deferred energy efficiency costs are recovered over the weighted average useful life of the related energy measure.	2031	Yes
Fair value of long-term debt	Represents the difference between the carrying value and fair value of long-term debt of PHI and BGE of $478 million and $120 million, respectively, as of December 31, 2020 and $523 million and $127 million, respectively, as of December 31, 2019, as of the PHI and Constellation merger dates.	BGE - 2036 PHI - 2045	No
Fair value of PHI's unamortized energy contracts	Represents the regulatory assets recorded at Exelon and PHI offsetting the fair value adjustment related to Pepco's, DPL's, and ACE's electricity and natural gas energy supply contracts recorded at PHI as of the PHI merger date.	2036	No
Asset retirement obligations	Future legally required removal costs associated with existing AROs.	Over the life of the related assets.	Yes, once the removal activities have been performed.
MGP remediation costs	Environmental remediation costs for MGP sites recorded at ComEd, PECO, and BGE.	Over the expected remediation period. See Note 19 — Commitments and Contingencies for additional information.	No

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Renewable energy	Represents the change in fair value of ComEd's 20-year floating-to-fixed long-term renewable energy swap contracts.	2032	No
Electric energy and natural gas costs	Under (over)-recoveries related to energy and gas supply related costs recoverable (refundable) under approved rate riders.	2025	DPL (Delaware), ACE - Yes ComEd, PECO, BGE, Pepco, DPL (Maryland) - No
Transmission formula rate annual reconciliations	Under (over)-recoveries related to transmission service costs recoverable through the Utility Registrants' FERC formula rates, which are updated annually with rates effective each June 1st.	2022	Yes
Energy efficiency and demand response programs	Includes under (over)-recoveries of costs incurred related to energy efficiency programs and demand response programs and recoverable costs associated with customer direct load control and energy efficiency and conservation programs that are being recovered from customers.	PECO - 2021 BGE - 2025 Pepco, DPL - 2035	BGE, Pepco, DPL - Yes PECO - Yes on capital investment recovered through this mechanism
Merger integration costs	Integration costs to achieve distribution synergies related to the Constellation merger and PHI acquisition. Costs for Pepco (Maryland) and Pepco (District of Columbia) were $3 million and $9 million, respectively as of December 31, 2020, which are included in Other in the table above, and $6 million and $9 million, respectively as of December 31, 2019.	BGE - 2021 Pepco - 2021 DPL - 2026 ACE - 2022	BGE, Pepco (Maryland), DPL - Yes Pepco (District of Columbia), ACE - No
Under (over)-recovered revenue decoupling	Electric and / or gas distribution costs recoverable from or (refundable) to customers under decoupling mechanisms.	BGE and DPL - 2021 Pepco (Maryland) - $16 million - 2021 Pepco (District of Columbia) - $31 million - 2021; $46 million to be determined by the DCPSC	BGE, Pepco, DPL - No
Stranded costs	The regulatory asset represents certain stranded costs associated with ACE's former electricity generation business. The regulatory liability represents overcollection of a customer surcharge collected by ACE to fund principal and interest payments on Transition Bonds of ACE Transition Funding that securitized such costs.	Stranded costs - 2022 Overcollection - To be determined by NJBPU	Stranded costs - Yes Overcollection - No

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Removal costs	For BGE, Pepco, DPL, and ACE, the regulatory asset represents costs incurred to remove property, plant and equipment in excess of amounts received from customers through depreciation rates. For ComEd, BGE, Pepco, and DPL, the regulatory liability represents amounts received from customers through depreciation rates to cover the future non–legally required cost to remove property, plant and equipment, which reduces rate base for ratemaking purposes.	BGE, Pepco, DPL, and ACE - Asset is generally recovered over the life of the underlying assets. ComEd, BGE, Pepco, and DPL - Liability is reduced as costs are incurred.	Yes
DC PLUG charge	Costs associated with DC PLUG, which is a projected six year, $500 million project to place underground some of the District of Columbia's most outage-prone power lines with $250 million of the project costs funded by Pepco and $250 million funded by the District of Columbia. Rates for the DC PLUG initiative went into effect on February 7, 2018.	2021 - $30 million $70 million to be determined based on future biennial plans filed with the DCPSC.	Portion of asset funded by Pepco-Yes
Deferred storm costs	For Pepco, DPL, and ACE amounts represent total incremental storm restoration costs incurred due to major storm events recoverable from customers in the Maryland and New Jersey jurisdictions.	Pepco - 2024 DPL - $2 million - 2025; $2 million not currently being recovered ACE - $5 million - 2021; $36 million not currently being recovered	Pepco, DPL - Yes ACE - No
Nuclear decommissioning	Estimated future decommissioning costs for the Regulatory Agreement Units that are less than the associated NDT fund assets. See Note 10 — Asset Retirement Obligations for additional information.	Not currently being refunded.	No
COVID-19	See COVID-19 section below for detail on the COVID-19 regulatory asset.	ComEd - 2024 BGE - 2025 PECO, Pepco, DPL, and ACE - Not currently being recovered.	ComEd and BGE - Yes PECO, Pepco, DPL, and ACE - No

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Under (over) -recovered credit loss expense	For ComEd and ACE, amounts represent the difference between annual credit loss expense and revenues collected in rates through ICC and NJBPU-approved riders. The difference between net credit loss expense and revenues collected through the rider each calendar year for ComEd is recovered or refunded over a twelve-month period beginning in June of the following calendar year. ACE intends to recover/refund from June through May of each respective year, subject to approval of the NJBPU.	ComEd - 2023 ACE - To be determined by NJBPU.	No
Renewable portfolio standards costs	Represents an overcollection of funds from both ComEd customers and alternative retail electricity suppliers to be spent on future renewable energy procurements. Costs were $320 million as of December 31, 2019, which are included in Other in the 2019 table above.	To be determined by the IPA and ICC.	No

COVID-19 (Exelon and the Utility Registrants). Starting in March of 2020, the Utility Registrants temporarily suspended customer disconnections for non-payment and temporarily ceased new late payment fees for all customers and restored service to customers upon request who were disconnected in the last twelve months. The duration and extent of these measures varies by jurisdiction. While these measures are no longer in place for some jurisdictions as of December 31, 2020, they are expected to continue through the first quarter of 2021 in other jurisdictions. Typically, the Utility Registrants recover credit loss expense through regulatory required programs or distribution base rate cases. ComEd and ACE have existing mechanisms for recovery of credit loss expense. For those jurisdictions without an existing regulatory required program to recover credit loss expense, the Utility Registrants are pursuing strategies to recover incremental costs being incurred as a result of COVID-19:

- In the period of April to July of 2020, the MDPSC, the DCPSC, the DPSC, and the NJBPU issued orders authorizing the creation of regulatory assets to track incremental COVID-19 related costs.
- In May of 2020, the PAPUC issued a Secretarial Letter authorizing the creation of regulatory assets to track incremental credit loss expense related to COVID-19.

The Utility Registrants have also incurred direct costs related to COVID-19 consisting primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of their employees.

The Utility Registrants have recorded regulatory assets for the impacts of COVID-19 reflecting primarily incremental credit losses and direct costs, partially offset by a decrease in travel costs at BGE and PHI. Refer to the Regulatory assets table above for amounts as of December 31, 2020. The Utility Registrants expect to seek recovery in upcoming distribution base rate cases.

Capitalized Ratemaking Amounts Not Recognized

The following table presents authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes in Exelon's and the Utility Registrant's Consolidated Balance Sheets. These amounts will be recognized as revenues in the related Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to our customers.

	Exelon	ComEd(a)	PECO	BGE(b)	PHI	Pepco(c)	DPL(c)	ACE
December 31, 2020	$ 51	$ (1)	$ —	$ 45	$ 7	$ 4	$ 3	$ —
December 31, 2019	$ 63	$ 3	$ —	$ 53	$ 7	$ 4	$ 3	$ —

(a) Reflects ComEd's unrecognized equity returns/(losses) earned/(incurred) for ratemaking purposes on its electric distribution formula rate regulatory assets.
(b) BGE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on its AMI programs.
(c) Pepco's and DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on their respective AMI Programs and Energy Efficiency and Demand Response Programs. The earnings on energy efficiency are on Pepco DC and DPL DE programs only.

Generation Regulatory Matters (Exelon and Generation)

Illinois Regulatory Matters

Zero Emission Standard. Pursuant to FEJA, on January 25, 2018, the ICC announced that Generation's Clinton Unit 1, Quad Cities Unit 1, and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event.

Generation executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue with compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. The ZEC price was initially established at $16.50 per MWh of production, subject to annual future adjustments determined by the IPA for specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices. Illinois utilities are required to purchase all ZECs delivered by the zero-emissions nuclear-powered generating facilities, subject to annual cost caps. For the initial delivery year, June 1, 2017 to May 31, 2018, and subsequent delivery year, June 1, 2018 to May 31, 2019, the ZEC annual cost cap was set at $235 million (ComEd's share is approximately $170 million). For subsequent delivery years, the IPA-approved targeted ZEC procurement amounts will change based on forward energy and capacity prices. ZECs delivered to Illinois utilities in excess of the annual cost cap may be paid in subsequent years if the payments do not exceed the prescribed annual cost cap for that year. During the first quarter of 2018, Generation recognized $150 million of revenue related to ZECs generated from June 1, 2017 through December 31, 2017.

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 $69 million and $53 million for the year ended December 31, 2020 and 2019, respectively. On May 15, 2019, New Jersey Rate Counsel appealed the NJBPU's decision to the New Jersey Superior Court. Briefing has been completed, and on December 9, 2020, oral argument took place. On October 1, 2020, PSEG and Generation filed applications seeking ZECs for the second eligibility period (June 2022 through May 2025). The NJBPU will act on the applications by the end of April 2021. Exelon and Generation cannot predict the outcome of the appeal. See Note 7 - 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. Due to COVID-19 related restrictions, the court extended the deadline to July 29, 2020. Petitioners did not file a brief by the deadline, so the case is deemed dismissed. Petitioners are permitted up to one year from July 29, 2020 to file a motion to vacate the dismissal if they can show good cause for the delay.

See Note 7 — Early Plant Retirements for additional information related to Ginna and Nine Mile Point.

New England Regulatory Matters

Mystic Units 8 & 9 and Everett Marine Terminal Cost of Service Agreement (Exelon and Generation). On March 29, 2018, Generation notified grid operator ISO-NE of its plans to early retire Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. On May 16, 2018, Generation made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 & 9 for the period between June 1, 2022 - May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service compensation, reflecting a number of adjustments to the annual fixed revenue requirement, and allowing for recovery of a substantial portion of the costs associated with the adjacent Everett Marine Terminal acquired by Generation in October 2018. Those adjustments were reflected in a compliance filing made on March 1, 2019. In the December 20, 2018 order, FERC also directed a paper hearing on ROE using a new methodology. On January 22, 2019, Exelon and several other parties filed requests for rehearing of certain findings in the order.

On July 17, 2020, FERC issued three orders, which together affirmed the recovery of key elements of Mystic's cost of service compensation, including recovery of costs associated with the operation of the Everett Marine Terminal. FERC directed a downward adjustment to the rate base for Mystic Units 8 and 9, the effect of which will be partially offset by elimination of a crediting mechanism for third party gas sales during the term of the cost of service agreement. A compliance filing was submitted on September 15, 2020 and is pending. Several parties filed protests to the compliance filing on the issue of how gross plant in-service was calculated and Generation filed an answer to the protests on October 21, 2020. On July 28, 2020, FERC ordered additional briefings in the ROE proceeding. On December 21, 2020, FERC issued an order on rehearing of the three July 17, 2020 orders, clarifying several cost of service provisions.

On August 25, 2020, a group of New England generators filed a complaint against Generation seeking to extend the scope of the claw back provision in the cost-of-service agreement, whereby Generation would refund certain amounts recovered during the term of the cost of service if it returns to market afterwards. On September 14, 2020, Generation filed an answer to the complaint arguing that the complaint is procedurally improper and a collateral attack on existing FERC orders, and pointing out that the ISO-NE tariff contains protections against the New England generators' concerns that they failed to mention. On September 28, 2020, New England generators filed an answer to Generation’s answer. Generation cannot predict the outcome of this proceeding.

On June 10, 2020, Generation filed a complaint with FERC against ISO-NE on the grounds that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic for transmission security for the 2024 to 2025 Capacity Commitment Period (FCA 15) and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic should have been filed with FERC for approval. On July 27, 2020, ISO-NE issued a memo to NEPOOL announcing its determination pursuant to its unfiled planning procedures that Mystic Units 8 and 9 are not needed for FCA 15 for transmission security. It had previously determined Mystic Units 8 and 9 are not needed for fuel security. On August 17, 2020, FERC issued an order denying the complaint. On September 16, 2020, Generation filed a request for rehearing with FERC. On October 19, 2020, FERC denied rehearing by operation of law and on December 18, 2020, Generation appealed to the U.S. Court of Appeals for the D.C. Circuit. The timing and the outcome of this proceeding is uncertain.

See Note 7 — Early Plant Retirements and Note 12 — Asset Impairments for additional information on the impacts of Generation’s August 2020 decision to retire Mystic Units 8 & 9 upon expiration of the cost of service agreement.

Federal Regulatory Matters

PJM and NYISO MOPR Proceedings. PJM and NYISO capacity markets include a MOPR. If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a state 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.

On December 19, 2019, FERC required PJM to broadly apply the MOPR to all new and existing resources including nuclear, renewables, demand response, energy efficiency, storage, and all resources owned by vertically-integrated utilities. This greatly expands the breadth and scope of PJM's MOPR, which is effective as of PJM's next capacity auction. While FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources.

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). In response to FERC’s order, PJM submitted a compliance filing on March 18, 2020 wherein PJM proposed tariff language interpreting and implementing FERC's directives, and proposed a schedule for resuming capacity auctions that is contingent on the timing of FERC's action on the compliance filing.

On April 16, 2020, FERC issued an order largely denying most requests for rehearing of FERC's December 2019 order but granting a few clarifications that required an additional PJM compliance filing which PJM submitted on June 1, 2020.

On October 15, 2020, FERC issued an order denying requests for rehearing of its April 16, 2020 order and accepting PJM's two compliance filings, subject to a further compliance filing to revise minor aspects of the proposed MOPR methodology. As part of that order, FERC also accepted PJM's proposal to condense the schedule of activities leading up to the next capacity auction. In November 2020, PJM announced that it will conduct its next capacity auction beginning on May 19, 2021 and ending on May 25, 2021 and will post the results on June 2, 2021.

Because neither Illinois nor New Jersey have implemented an FRR program in their PJM zones, the MOPR will apply in that next capacity auction 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 as an alternative to the PJM capacity auction. 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 7 — Early Plant Retirements. Implementing the FRR program in Illinois will require both legislative and regulatory changes. Whether legislation is needed in New Jersey would depend on how the state chooses to structure an FRR program. Exelon cannot predict whether or when such legislative and regulatory changes can be implemented.

On February 20, 2020, FERC issued an order rejecting requests to expand NYISO's version of the MOPR (referred to as buyer-side mitigation rules) beyond its current limited applicability to certain resources in downstate. However, on October 14, 2020, two natural gas-fired generators in New York filed a complaint at FERC seeking to expand the MOPR in NYISO to apply to all resources, new and existing, across the entire NYISO market. Exelon is strenuously opposing expansion of FERC's MOPR policies in the NYISO market. While it is too early in the proceeding to predict its outcome and there are significant differences between the NYISO and PJM markets that would justify a different result, if FERC follows its MOPR precedent in PJM and applies the MOPR in NYISO broadly as requested in the complaint, Generation's facilities in NYISO that are receiving ZEC compensation may be at increased risk of not clearing the capacity auction.

If Generation's state-supported nuclear plants in PJM or NYISO 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.

On April 21, 2016, Generation and the U.S. Fish and Wildlife Service of the U.S. Department of the Interior executed a settlement agreement (DOI Settlement) resolving all fish passage issues between the parties.

On April 27, 2018, MDE issued its 401 Certification for Conowingo. As issued, the 401 Certification contains numerous conditions, including those relating to reduction of nutrients from upstream sources, removal of all visible trash and debris from upstream sources, and implementation of measures relating to fish passage, which could have a material, unfavorable impact on Exelon's and Generation's financial statements through an increase in capital expenditures and operating costs if implemented. On May 25, 2018, Generation filed complaints in federal and state court, along with a petition for reconsideration with MDE, alleging that the conditions are unfair and onerous and in violation of MDE regulations and state, federal, and constitutional law. Generation also requested that FERC defer the issuance of the federal license while these significant state and federal law issues are pending. On February 28, 2019, Generation filed a Petition for Declaratory Order with FERC requesting that FERC issue an order declaring that MDE waived its right to issue a 401 Certification for Conowingo because it failed to timely act on Conowingo's 401 Certification application and requesting that FERC decline to include the conditions required by MDE in April 2018.

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.

The financial impact of the DOI and MDE Settlements and other anticipated license commitments are estimated to be $11 million to $14 million per year, on average, recognized over the new license term, including capital and operating costs. The actual timing and amount of the majority of these costs are not currently fixed and will vary from year to year throughout the life of the new license. Generation cannot currently predict when FERC will issue the new license. As of December 31, 2020, $45 million of direct costs associated with Conowingo licensing efforts have been capitalized. Generation's current depreciation provision for Conowingo assumes renewal of the FERC 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. See Note 8 – Property, Plant, and Equipment for additional information regarding the estimated useful life and depreciation provisions for Peach Bottom.

4. Revenue from Contracts with Customers (All Registrants)

The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that the entities expect to be entitled to in exchange for those goods or services. Generation's primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The Utility Registrants' primary sources of revenue include regulated electric and gas tariff sales, distribution, and transmission services. The performance obligations, revenue recognition, and payment terms associated with these sources of revenue are further discussed in the table below. There are no significant financing components for these sources of revenue and no variable consideration for regulated electric and gas tariff sales and regulated transmission services unless noted below.

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

Revenue Source	Description	Performance Obligation	Timing of Revenue Recognition	Payment Terms
Competitive Power Sales (Exelon and Generation)	Sales of power and other energy-related commodities to wholesale and retail customers across multiple geographic regions through its customer-facing business, Constellation.	Various including the delivery of power (generally delivered over time) and other energy-related commodities such as capacity (generally delivered over time), ZECs, RECs or other ancillary services (generally delivered at a point in time).	Concurrently as power is generated for bundled power sale contracts. (a)	Within the month following delivery to the customer.
Competitive Natural Gas Sales (Exelon and Generation)	Sales of natural gas on a full requirement basis or for an agreed upon volume to commercial and residential customers.	Delivery of natural gas to the customer.	Over time as the natural gas is delivered and consumed by the customer.	Within the month following delivery to the customer.
Other Competitive Products and Services (Exelon and Generation)	Sales of other energy-related products and services such as long-term construction and installation of energy efficiency assets and new power generating facilities, primarily to commercial and industrial customers.	Construction and/or installation of the asset for the customer.	Revenues and associated costs are recognized throughout the contract term using an input method to measure progress towards completion.(b)	Within 30 or 45 days from the invoice date.
Regulated Electric and Gas Tariff Sales (Exelon and the Utility Registrants)	Sales of electricity and electricity distribution services (the Utility Registrants) and natural gas and gas distribution services (PECO, BGE, and DPL) to residential, commercial, industrial, and governmental customers through regulated tariff rates approved by state regulatory commissions.	Delivery of electricity and/or natural gas.	Over time (each day) as the electricity and/or natural gas is delivered to customers. Tariff sales are generally considered daily contracts as customers can discontinue service at any time. (c)	Within the month following delivery of the electricity or natural gas to the customer.
Regulated Transmission Services (Exelon and the Utility Registrants)	The Utility Registrants provide open access to their transmission facilities to PJM, which directs and controls the operation of these transmission facilities and accordingly compensates the Utility Registrants pursuant to filed tariffs at cost-based rates approved by FERC.	Various including (i) Network Integration Transmission Services (NITS), (ii) scheduling, system control and dispatch services, and (iii) access to the wholesale grid.	Over time utilizing output methods to measure progress towards completion. (d)	Paid weekly by PJM.

(a) Certain contracts may contain limits on the total amount of revenue Exelon and Generation are able to collect over the entire term of the contract. In such cases, Exelon and Generation estimate the total consideration expected to be received over the term of the contract net of the constraint and allocate the expected consideration to the performance obligations in the contract such that revenue is recognized ratably over the term of the entire contract as the performance obligations are satisfied.

(b) The method recognizes revenue based on the various inputs used to satisfy the performance obligation, such as costs incurred and total labor hours expended. The total amount of revenue that will be recognized is based on the agreed upon contractually-stated amount. The average contract term for these projects is approximately 18 months.

(c) Electric and natural gas utility customers have the choice to purchase electricity or natural gas from competitive electric generation and natural gas suppliers. While the Utility Registrants are required under state legislation to bill their customers for the supply and distribution of electricity and/or natural gas, they recognize revenue related only to the distribution services when customers purchase their electricity or natural gas from competitive suppliers.

(d) Passage of time is used for NITS and access to the wholesale grid and MWHs of energy transported over the wholesale grid is used for scheduling, system control and dispatch services.

Generation incurs incremental costs in order to execute certain retail power and gas sales contracts. These costs, which primarily relate to retail broker fees and sales commissions, are capitalized when incurred as contract acquisition costs and were immaterial as of December 31, 2020 and 2019. The Utility Registrants do not incur any material costs to obtain or fulfill contracts with customers.

Contract Balances (All Registrants)

Contract Assets

Generation records contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before Generation has an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. Generation records contract assets and contract receivables within Other current assets and Customer accounts receivable, net, respectively, within Exelon's and Generation's Consolidated Balance Sheets.

The following table provides a rollforward of the contract assets reflected in Exelon's and Generation's Consolidated Balance Sheets. The Utility Registrants do not have any contract assets.

	Exelon	Generation
Balance as of December 31, 2018	$ 187	$ 187
Amounts reclassified to receivables	(143)	(143)
Revenues recognized	130	130
Balance at December 31, 2019	174	174
Amounts reclassified to receivables	(86)	(86)
Revenues recognized	68	68
Contract assets reclassified as held for sale[a]	(12)	(12)
Balance at December 31, 2020	$ 144	$ 144

(a) Represents contract assets related to Generation's solar business, which were classified as held for sale as a result of the sale agreement. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

Contract Liabilities

The Registrants record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. The Registrants record contract liabilities within Other current liabilities and Other noncurrent liabilities within the Registrants' Consolidated Balance Sheets.

For Generation, these contract liabilities primarily relate to upfront consideration received or due for equipment service plans, solar panel leases, and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation. The Generation contract liability related to the Illinois ZEC program includes certain amounts with ComEd that are eliminated in consolidation in Exelon's Consolidated Statements of Operations and Consolidated Balance Sheets.

On July 1, 2020, Pepco, DPL, and ACE each entered into a collaborative arrangement with an unrelated owner and manager of communication infrastructure (the Buyer). Under this arrangement, Pepco, DPL, and ACE sold a 60% undivided interest in their respective portfolios of transmission tower attachment agreements with telecommunications companies to the Buyer, in addition to transitioning management of the day-to-day operations of the jointly-owned agreements to the Buyer for 35 years, while retaining the safe and reliable operation of its utility assets. In return, Pepco, DPL, and ACE will provide the Buyer limited access on the portion of the towers where the equipment resides for the purposes of managing the agreements for the benefit of Pepco, DPL, ACE, and the Buyer. In addition, for an initial period of three years and two, two-year extensions that are subject to certain conditions, the Buyer has the exclusive right to enter into new agreements with telecommunications companies and to receive a 30% undivided interest in those new agreements. PHI, Pepco, DPL, and ACE received cash and recorded contract liabilities as of July 1, 2020 as shown in the table below. The revenue attributable to this arrangement will be recognized as operating revenue over the 35 years under the collaborative arrangement.

The following table provides a rollforward of the contract liabilities reflected in Exelon's, Generation's, PHI's, Pepco's, DPL's, and ACE'S Consolidated Balance Sheets. As of December 31, 2020, 2019, and 2018, ComEd's, PECO's, and BGE's contract liabilities were immaterial.

	Exelon	Generation	PHI	Pepco	DPL	ACE
Balance as of December 31, 2017	$ 35	$ 35	$ —	$ —	$ —	$ —
Consideration received or due	179	465	—	—	—	—
Revenues recognized	(187)	(458)	—	—	—	—
Balance as of December 31, 2018	27	42	—	—	—	—
Consideration received or due	94	287	—	—	—	—
Revenues recognized	(88)	(258)	—	—	—	—
Balance at December 31, 2019	33	71	—	—	—	—
Consideration received or due	219	282	122	98	12	12
Revenues recognized	(98)	(266)	(4)	(4)	—	—
Contracts liabilities reclassified as held for sale[(a)]	(3)	(3)	—	—	—	—
Balance at December 31, 2020	$ 151	$ 84	$ 118	$ 94	$ 12	$ 12

(a) Represents contract liabilities related to Generation's solar business, which were classified as held for sale as a result of the sale agreement. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

The following table reflects revenues recognized in the years ended December 31, 2020, 2019 and 2018, which were included in contract liabilities at December 31, 2019, 2018, and 2017, respectively:

	2020	2019	2018
Exelon	$ 27	$ 18	$ 11
Generation	64	32	11

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 December 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.

	2021	2022	2023	2024	2025 and thereafter	Total
Exelon	$ 262	$ 93	$ 54	$ 40	$ 330	$ 779
Generation	352	124	55	34	243	808
PHI	9	8	8	6	87	118
Pepco	7	6	6	5	70	94
DPL	1	1	1	—	9	12
ACE	1	1	1	1	8	12

Revenue Disaggregation (All Registrants)

The Registrants disaggregate revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 5 — Segment Information for the presentation of the Registrant's revenue disaggregation.

5. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the CODM in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has eleven reportable segments, which include Generation's five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and all other power regions referred to collectively as “Other Power Regions” and ComEd, PECO, BGE, and PHI's three reportable segments consisting of Pepco, DPL, and ACE. ComEd, PECO, BGE, Pepco, DPL, and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO, BGE, Pepco, DPL, and ACE's CODMs evaluate the performance of and allocate resources to ComEd, PECO, BGE, Pepco, DPL, and ACE based on net income.

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of Generation’s five reportable segments are as follows:

- **Mid-Atlantic** represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia, and parts of Pennsylvania and North Carolina.
- **Midwest** represents operations in the western half of PJM and the United States footprint of MISO, excluding MISO’s Southern Region.
- **New York** represents operations within NYISO.
- **ERCOT** represents operations within Electric Reliability Council of Texas.
- **Other Power Regions:**
  - **New England** represents 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 CAISO.
  - **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 years ended December 31, 2020, 2019, and 2018 is as follows:

	Generation	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
Operating revenues[b]:								
2020								
Competitive businesses electric revenues	$ 15,060	$ —	$ —	$ —	$ —	$ —	$ (1,196)	$ 13,864
Competitive businesses natural gas revenues	2,003	—	—	—	—	—	(3)	2,000
Competitive businesses other revenues	540	—	—	—	—	—	(4)	536
Rate-regulated electric revenues	—	5,904	2,543	2,336	4,485	—	(61)	15,207
Rate-regulated natural gas revenues	—	—	515	762	162	—	(7)	1,432
Shared service and other revenues	—	—	—	—	16	2,035	(2,051)	—
Total operating revenues	$ 17,603	$ 5,904	$ 3,058	$ 3,098	$ 4,663	$ 2,035	$ (3,322)	$ 33,039
2019								
Competitive businesses electric revenues	$ 16,285	$ —	$ —	$ —	$ —	$ —	$ (1,165)	$ 15,120
Competitive businesses natural gas revenues	2,148	—	—	—	—	—	(1)	2,147
Competitive businesses other revenues	491	—	—	—	—	—	(4)	487
Rate-regulated electric revenues	—	5,747	2,490	2,379	4,626	—	(47)	15,195
Rate-regulated natural gas revenues	—	—	610	727	167	—	(15)	1,489
Shared service and other revenues	—	—	—	—	13	1,921	(1,934)	—
Total operating revenues	$ 18,924	$ 5,747	$ 3,100	$ 3,106	$ 4,806	$ 1,921	$ (3,166)	$ 34,438

	Generation	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
2018								
Competitive businesses electric revenues	$ 17,411	$ —	$ —	$ —	$ —	$ —	$ (1,256)	$ 16,155
Competitive businesses natural gas revenues	2,718	—	—	—	—	—	(8)	2,710
Competitive businesses other revenues	308	—	—	—	—	—	(5)	303
Rate-regulated electric revenues	—	5,882	2,470	2,428	4,602	—	(45)	15,337
Rate-regulated natural gas revenues	—	—	568	741	181	—	(20)	1,470
Shared service and other revenues	—	—	—	—	15	1,948	(1,960)	3
Total operating revenues	$ 20,437	$ 5,882	$ 3,038	$ 3,169	$ 4,798	$ 1,948	$ (3,294)	$ 35,978
Intersegment revenues[c]:								
2020	$ 1,211	$ 37	$ 9	$ 20	$ 17	$ 2,024	$ (3,314)	$ 4
2019	1,172	30	6	26	14	1,913	(3,159)	2
2018	1,269	27	8	29	15	1,942	(3,289)	1
Depreciation and amortization:								
2020	$ 2,123	$ 1,133	$ 347	$ 550	$ 782	$ 79	$ —	$ 5,014
2019	1,535	1,033	333	502	754	95	—	4,252
2018	1,797	940	301	483	740	92	—	4,353
Operating expenses:								
2020	$ 17,358	$ 4,950	$ 2,512	$ 2,598	$ 4,045	$ 2,047	$ (3,270)	$ 30,240
2019	17,628	4,580	2,388	2,574	4,084	1,996	(3,154)	30,096
2018	19,510	4,741	2,452	2,696	4,156	1,929	(3,341)	32,143
Interest expense, net:								
2020	$ 357	$ 382	$ 147	$ 133	$ 268	$ 351	$ (3)	$ 1,635
2019	429	359	136	121	263	308	—	1,616
2018	432	347	129	106	261	279	—	1,554
Income (loss) before income taxes:								
2020	$ 836	$ 615	$ 417	$ 390	$ 418	$ (343)	$ —	$ 2,333
2019	1,917	851	593	439	514	(327)	(2)	3,985
2018	365	832	466	387	425	(249)	(1)	2,225
Income taxes:								
2020	$ 249	$ 177	$ (30)	$ 41	$ (77)	$ 13	$ —	$ 373
2019	516	163	65	79	38	(87)	—	774
2018	(108)	168	6	74	33	(55)	—	118
Net income (loss):								
2020	$ 579	$ 438	$ 447	$ 349	$ 495	$ (354)	$ —	$ 1,954
2019	1,217	688	528	360	477	(240)	(2)	3,028

	Generation	ComEd	PECO	BGE	PHI	Other[(a)]	Intersegment Eliminations	Exelon
2018	443	664	460	313	393	(193)	(1)	2,079
Capital expenditures:								
2020	$ 1,747	$ 2,217	$ 1,147	$ 1,247	$ 1,604	$ 86	$ —	$ 8,048
2019	1,845	1,915	939	1,145	1,355	49	—	7,248
2018	2,242	2,126	849	959	1,375	43	—	7,594
Total assets:								
2020	$ 48,094	$ 34,466	$ 12,531	$ 11,650	$ 23,736	$ 9,005	$ (10,165)	$ 129,317
2019	48,995	32,765	11,469	10,634	22,719	8,484	(10,089)	124,977

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

(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants’ Consolidated Statements of Operations and Comprehensive Income. See Note 24 — Supplemental Financial Information for additional information on total utility taxes.

(c) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation’s sale of certain products and services by and between Exelon’s segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income. See Note 25 - Related Party Transactions for additional information on intersegment revenues.

PHI:

	Pepco	DPL	ACE	Other(a)	Intersegment Eliminations	PHI
Operating revenues(b):						
2020						
Rate-regulated electric revenues	$ 2,149	$ 1,109	$ 1,245	$ —	$ (18)	$ 4,485
Rate-regulated natural gas revenues	—	162	—	—	—	162
Shared service and other revenues	—	—	—	372	(356)	16
Total operating revenues	$ 2,149	$ 1,271	$ 1,245	$ 372	$ (374)	$ 4,663
2019						
Rate-regulated electric revenues	$ 2,260	$ 1,139	$ 1,240	$ —	$ (13)	$ 4,626
Rate-regulated natural gas revenues	—	167	—	—	—	167
Shared service and other revenues	—	—	—	396	(383)	13
Total operating revenues	$ 2,260	$ 1,306	$ 1,240	$ 396	$ (396)	$ 4,806
2018						
Rate-regulated electric revenues	$ 2,232	$ 1,151	$ 1,236	$ —	$ (17)	$ 4,602
Rate-regulated natural gas revenues	—	181	—	—	—	181
Shared service and other revenues	—	—	—	435	(420)	15
Total operating revenues	$ 2,232	$ 1,332	$ 1,236	$ 435	$ (437)	$ 4,798
Intersegment revenues(c):						
2020	$ 7	$ 9	$ 4	$ 372	$ (375)	$ 17
2019	5	7	3	396	(397)	14
2018	6	8	3	435	(437)	15
Depreciation and amortization:						
2020	$ 377	$ 191	$ 180	$ 34	$ —	$ 782
2019	374	184	157	39	—	754
2018	385	182	136	37	—	740
Operating expenses:						
2020	$ 1,799	$ 1,120	$ 1,123	$ 378	$ (375)	$ 4,045
2019	1,899	1,089	1,089	403	(396)	4,084
2018	1,919	1,143	1,087	442	(435)	4,156
Interest expense, net:						
2020	$ 138	$ 61	$ 59	$ 10	$ —	$ 268
2019	133	61	58	10	1	263
2018	128	58	64	11	—	261
Income (loss) before income taxes:						
2020	$ 259	$ 100	$ 71	$ (12)	$ —	$ 418
2019(d)	259	169	99	(13)	—	514
2018(d)	216	142	87	(20)	—	425
Income taxes:						
2020	$ (7)	$ (25)	$ (41)	$ (4)	$ —	$ (77)
2019	16	22	—	—	—	38
2018	11	22	12	(12)	—	33

	Pepco	DPL	ACE	Other(a)	Intersegment Eliminations	PHI
Net income (loss):						
2020	$ 266	$ 125	$ 112	$ (8)	$ —	$ 495
2019	243	147	99	(12)	—	477
2018	205	120	75	(7)	—	393
Capital expenditures:						
2020	$ 773	$ 424	$ 401	$ 6	$ —	$ 1,604
2019	626	348	375	6	—	1,355
2018	656	364	335	20	—	1,375
Total assets:						
2020	$ 9,264	$ 5,140	$ 4,286	$ 5,079	$ (33)	$ 23,736
2019(d)	8,661	4,830	3,933	5,335	(40)	22,719

(a) Other primarily includes PHI's corporate operations, shared service entities, and other financing and investment activities.
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 24 — Supplemental Financial Information for additional information on total utility taxes.
(c) Includes intersegment revenues with ComEd, BGE, and PECO, which are eliminated at Exelon.
(d) The Income (loss) before income taxes in Other and Intersegment Eliminations have been adjusted by an offsetting $489 million and $408 million in 2019 and 2018, respectively, and Total assets amounts in Other and Intersegment Eliminations have been adjusted by an offsetting $5.7 billion in 2019 for consistency with the Exelon consolidating disclosure above.

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):

	2020				
	Revenues from external customers(a)				
	Contracts with customers	Other(b)	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 4,785	$ (168)	$ 4,617	$ 28	$ 4,645
Midwest	3,717	312	4,029	(5)	4,024
New York	1,444	(12)	1,432	(1)	1,431
ERCOT	735	198	933	25	958
Other Power Regions	3,586	463	4,049	(47)	4,002
Total Competitive Businesses Electric Revenues	$ 14,267	$ 793	$ 15,060	$ —	$ 15,060
Competitive Businesses Natural Gas Revenues	1,283	720	2,003	—	2,003
Competitive Businesses Other Revenues(c)	355	185	540	—	540
Total Generation Consolidated Operating Revenues	$ 15,905	$ 1,698	$ 17,603	$ —	$ 17,603

	2019				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 5,053	$ 17	$ 5,070	$ 4	$ 5,074
Midwest	4,095	232	4,327	(34)	4,293
New York	1,571	25	1,596	—	1,596
ERCOT	768	229	997	16	1,013
Other Power Regions	3,687	608	4,295	(49)	4,246
Total Competitive Businesses Electric Revenues	$ 15,174	$ 1,111	$ 16,285	$ (63)	$ 16,222
Competitive Businesses Natural Gas Revenues	1,446	702	2,148	62	2,210
Competitive Businesses Other Revenues[c]	440	51	491	1	492
Total Generation Consolidated Operating Revenues	$ 17,060	$ 1,864	$ 18,924	$ —	$ 18,924

	2018				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 5,241	$ 233	$ 5,474	$ 13	$ 5,487
Midwest	4,527	190	4,717	(11)	4,706
New York	1,723	(36)	1,687	—	1,687
ERCOT	572	560	1,132	1	1,133
Other Power Regions	3,530	871	4,401	(66)	4,335
Total Competitive Businesses Electric Revenues	$ 15,593	$ 1,818	$ 17,411	$ (63)	$ 17,348
Competitive Businesses Natural Gas Revenues	1,524	1,194	2,718	62	2,780
Competitive Businesses Other Revenues[c]	510	(202)	308	1	309
Total Generation Consolidated Operating Revenues	$ 17,627	$ 2,810	$ 20,437	$ —	$ 20,437

(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) Represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market gains of $110 million and losses of $4 million and $262 million for the years ended December 31, 2020, 2019, and 2018, respectively, and the elimination of intersegment revenues.

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

	2020			2019			2018		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 2,174	$ 30	$ 2,204	$ 2,637	$ 18	$ 2,655	$ 3,022	$ 51	$ 3,073
Midwest	2,902	—	2,902	2,994	(32)	2,962	3,112	23	3,135
New York	983	14	997	1,081	13	1,094	1,112	10	1,122
ERCOT	407	19	426	338	(30)	308	501	(243)	258
Other Power Regions	759	(94)	665	694	(74)	620	883	(154)	729
Total RNF for Reportable Segments	$ 7,225	$ (31)	$ 7,194	$ 7,744	$ (105)	$ 7,639	$ 8,630	$ (313)	$ 8,317
Other[b]	793	31	824	324	105	429	114	313	427
Total Generation RNF	$ 8,018	$ —	$ 8,018	$ 8,068	$ —	$ 8,068	$ 8,744	$ —	$ 8,744

(a) Includes purchases and sales from/to third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Primarily includes:

- unrealized mark-to-market gains of $295 million and losses of $215 million and $319 million for the years ended December 31, 2020, 2019, and 2018, respectively;
- accelerated nuclear fuel amortization associated with the announced early plant retirements as discussed in Note 7 - Early Plant Retirements of $60 million, $13 million, and $57 million in for the years ended December 31, 2020, 2019, and 2018, respectively; and
- the elimination of intersegment RNF.

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

	2020						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$ 3,090	$ 1,656	$ 1,345	$ 2,332	$ 988	$ 652	$ 692
Small commercial & industrial	1,399	386	241	472	132	171	169
Large commercial & industrial	515	228	406	1,001	736	89	176
Public authorities & electric railroads	45	29	27	60	34	13	13
Other(a)	884	225	309	613	218	190	207
Total rate-regulated electric revenues(b)	$ 5,933	$ 2,524	$ 2,328	$ 4,478	$ 2,108	$ 1,115	$ 1,257
Rate-regulated natural gas revenues							
Residential	$ —	$ 361	$ 504	$ 96	$ —	$ 96	$ —
Small commercial & industrial	—	126	79	42	—	42	—
Large commercial & industrial	—	—	135	4	—	4	—
Transportation	—	24	—	14	—	14	—
Other(c)	—	4	29	6	—	6	—
Total rate-regulated natural gas revenues(d)	$ —	$ 515	$ 747	$ 162	$ —	$ 162	$ —
Total rate-regulated revenues from contracts with customers	$ 5,933	$ 3,039	$ 3,075	$ 4,640	$ 2,108	$ 1,277	$ 1,257
Other revenues							
Revenues from alternative revenue programs	$ (47)	$ 16	$ 16	$ 21	$ 40	$ (7)	$ (12)
Other rate-regulated electric revenues(e)	18	3	5	2	1	1	—
Other rate-regulated natural gas revenues(e)	—	—	2	—	—	—	—
Total other revenues	$ (29)	$ 19	$ 23	$ 23	$ 41	$ (6)	$ (12)
Total rate-regulated revenues for reportable segments	$ 5,904	$ 3,058	$ 3,098	$ 4,663	$ 2,149	$ 1,271	$ 1,245

	2019						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$ 2,916	$ 1,596	$ 1,326	$ 2,316	$ 1,012	$ 645	$ 659
Small commercial & industrial	1,463	404	254	505	149	186	170
Large commercial & industrial	540	219	436	1,112	833	99	180
Public authorities & electric railroads	47	29	27	61	34	14	13
Other(a)	888	249	321	650	227	204	218
Total rate-regulated electric revenues(b)	$ 5,854	$ 2,497	$ 2,364	$ 4,644	$ 2,255	$ 1,148	$ 1,240
Rate-regulated natural gas revenues							
Residential	$ —	$ 409	$ 474	$ 96	$ —	$ 96	$ —
Small commercial & industrial	—	169	77	44	—	45	—
Large commercial & industrial	—	1	132	5	—	5	—
Transportation	—	25	—	14	—	14	—
Other(c)	—	6	31	7	—	7	—
Total rate-regulated natural gas revenues(d)	$ —	$ 610	$ 714	$ 166	$ —	$ 167	$ —
Total rate-regulated revenues from contracts with customers	$ 5,854	$ 3,107	$ 3,078	$ 4,810	$ 2,255	$ 1,315	$ 1,240
Other revenues							
Revenues from alternative revenue programs	$ (133)	$ (21)	$ 12	$ (14)	$ (3)	$ (11)	$ —
Other rate-regulated electric revenues(e)	26	13	12	10	8	2	—
Other rate-regulated natural gas revenues(e)	—	1	4	—	—	—	—
Total other revenues	$ (107)	$ (7)	$ 28	$ (4)	$ 5	$ (9)	$ —
Total rate-regulated revenues for reportable segments	$ 5,747	$ 3,100	$ 3,106	$ 4,806	$ 2,260	$ 1,306	$ 1,240

	2018						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$ 2,942	$ 1,566	$ 1,382	$ 2,351	$ 1,021	$ 669	$ 661
Small commercial & industrial	1,487	404	257	488	140	186	162
Large commercial & industrial	538	223	429	1,124	846	100	178
Public authorities & electric railroads	47	28	28	58	32	14	12
Other[a]	867	243	327	593	193	175	227
Total rate-regulated electric revenues[b]	$ 5,881	$ 2,464	$ 2,423	$ 4,614	$ 2,232	$ 1,144	$ 1,240
Rate-regulated natural gas revenues							
Residential	$ —	$ 395	$ 491	$ 99	$ —	$ 99	$ —
Small commercial & industrial	—	143	77	44	—	44	—
Large commercial & industrial	—	1	124	8	—	8	—
Transportation	—	23	—	16	—	16	—
Other[c]	—	6	63	13	—	13	—
Total rate-regulated natural gas revenues[d]	$ —	$ 568	$ 755	$ 180	$ —	$ 180	$ —
Total rate-regulated revenues from contracts with customers	$ 5,881	$ 3,032	$ 3,178	$ 4,794	$ 2,232	$ 1,324	$ 1,240
Other revenues							
Revenues from alternative revenue programs	$ (29)	$ (7)	$ (26)	$ (7)	$ (7)	$ 4	$ (4)
Other rate-regulated electric revenues[e]	30	12	13	10	7	3	—
Other rate-regulated natural gas revenues[e]	—	1	4	1	—	1	—
Total other revenues	$ 1	$ 6	$ (9)	$ 4	$ —	$ 8	$ (4)
Total rate-regulated revenues for reportable segments	$ 5,882	$ 3,038	$ 3,169	$ 4,798	$ 2,232	$ 1,332	$ 1,236

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

(b) Includes operating revenues from affiliates in 2020, 2019, and 2018 respectively of:
  - $37 million, $30 million, and $27 million at ComEd
  - $8 million, $5 million, and $7 million at PECO
  - $10 million, $8 million, and $8 million at BGE
  - $17 million, $14 million, and $15 million at PHI
  - $7 million, $5 million, and $6 million at Pepco
  - $9 million, $7 million, and $8 million at DPL
  - $4 million, $3 million, and $3 million at ACE

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

(d) Includes operating revenues from affiliates in 2020, 2019, and 2018 respectively of:
  - $1 million, $1 million, and $1 million at PECO
  - $10 million, $18 million, and $21 million at BGE

(e) Includes late payment charge revenues.

6. Accounts Receivable (All Registrants)

Allowance for Credit Losses on Accounts Receivable (All Registrants)

The following table presents the rollforward of Allowance for Credit Losses on Customer Accounts Receivable for the year ended December 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[(a)]	248	13	62	79	30	64	24	15	25
Less: Write-offs, net of recoveries[(b)]	69	5	24	18	7	15	5	4	6
Less: Sale of customer accounts receivable[(c)]	56	56	—	—	—	—	—	—	—
Balance as of December 31, 2020	$ 366	$ 32	$ 97	$ 116	$ 35	$ 86	$ 32	$ 22	$ 32

(a) For the Utility Registrants, the increase is primarily as a result of increased aging of receivables, the temporary suspension of customer disconnections for non-payment, temporary cessation of new late payment fees, and reconnection of service to customers previously disconnected due to COVID-19.
(b) Recoveries were not material to the Registrants.
(c) See below for additional information on the sale of customer accounts receivable at Generation in the second quarter of 2020.

The following table presents the rollforward of Allowance for Credit Losses on Other Accounts Receivable for the year ended December 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	33	—	5	3	7	18	6	5	7
Less: Write-offs, net of recoveries[(a)]	10	—	4	2	3	1	—	—	1
Balance as of December 31, 2020	$ 71	$ —	$ 21	$ 8	$ 9	$ 33	$ 13	$ 9	$ 11

(a) Recoveries were not material to the Registrants.

Unbilled Customer Revenue (All Registrants)

The following table provides additional information about unbilled customer revenues recorded in the Registrants' Consolidated Balance Sheets as of December 31, 2020 and 2019.

	Unbilled customer revenues[(a)]								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2020	$ 998	$ 258	$ 218	$ 147	$ 197	$ 178	$ 87	$ 62	$ 29
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.

Sales of Customer Accounts Receivable (Exelon and Generation)

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly-owned by Generation, entered into a revolving accounts receivable financing arrangement with a number of financial institutions and a commercial paper conduit (the Purchasers) to sell certain customer accounts receivable (the Facility). The Facility, 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 DPP, which is reflected in Other current assets on Exelon's and Generation's Consolidated Balance Sheet.

On April 8, 2020, Generation derecognized and transferred approximately $1.2 billion of receivables at fair value to the Purchasers in exchange for approximately $500 million in cash purchase price and $650 million of DPP. On February 17, 2021, Generation received additional cash of $250 million from the Purchasers for the remaining capacity in the Facility.

The following table summarizes the impact of the sale of certain receivables:

	As of December 31, 2020
Derecognized receivables transferred at fair value[(a)]	$ 1,139
Cash proceeds received	500
DPP	639

(a) Includes additional customer accounts receivable sold into the Facility of $6,608 million since the start of the financing agreement.

	For the year ended December 31, 2020
Loss on sale of receivables[(a)]	$ 30

(a) Reflected in Operating and maintenance expense on Exelon and Generation's Consolidated Statement of Operations and Comprehensive Income.

	For the year ended December 31, 2020
Proceeds from new transfers	$ 2,816
Cash collections received on DPP	3,771
Cash collections reinvested in the Facility	6,587

Generation's risk of loss following the transfer of accounts receivable is limited to the DPP outstanding. Payment of DPP is not subject to significant risks other than delinquencies and credit losses on accounts receivable transferred, which have historically been and are expected to be immaterial. Generation continues to service the receivables sold in exchange for a servicing fee. Generation did not record a servicing asset or liability as the servicing fees were immaterial.

Generation recognizes the cash proceeds received upon sale in Net cash provided by operating activities in the Consolidated Statement of Cash Flows. The collection and reinvestment of DPP is recognized in Net cash provided by investing activities of the Consolidated Statement of Cash Flows.

See Note 18 — Fair Value of Financial Assets and Liabilities and Note 23 — Variable Interest Entities for additional information.

Other Purchases and Sales of Customer and Other Accounts Receivables (All Registrants)

Generation is required, under supplier tariffs in ISO-NE, MISO, NYISO, and PJM, to sell customer and other receivables to utility companies, which include the Utility Registrants. The Utility Registrants are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia, and New Jersey, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participate in the utilities' consolidated billing. The following tables present the total receivables purchased and sold for the year ended December 31, 2020.

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Total Receivables Purchased	$ 3,529	$ —	$ 1,094	$ 1,020	$ 652	$ 1,015	$ 622	$ 207	$ 186
Total Receivables Sold	572	824	—	—	—	—	—	—	—
Related Party Transactions:									
Receivables purchased from Generation	—	—	34	67	79	72	51	13	8
Receivables sold to the Utility Registrants	—	252	—	—	—	—	—	—	—

7. Early Plant Retirements (Exelon and Generation)

Exelon and Generation continuously evaluate factors that affect the current and expected economic value of Generation's plants, including, but not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure plants are fairly compensated for benefits they provide through their carbon-free emissions, reliability, or fuel security, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any plant, and the resulting financial statement impacts, may be affected by many factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and NDT fund requirements for nuclear plants, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

Nuclear Generation

In 2015 and 2016, Generation identified the Clinton and Quad Cities nuclear plants in Illinois, Ginna and Nine Mile Point nuclear plants in New York, and TMI nuclear plant in Pennsylvania as having the greatest risk of early retirement based on economic valuation and other factors. In 2017, PSEG made public similar financial challenges facing its New Jersey nuclear plants, including Salem, of which Generation owns a 42.59% ownership interest. PSEG is the operator of Salem and also has the decision-making authority to retire Salem.

Assuming the continued effectiveness of the Illinois ZES, New Jersey ZEC program, and the New York CES, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Salem, Ginna, or Nine Mile Point to be at heightened risk for early retirement. However, to the extent the Illinois ZES, New Jersey ZEC program, or the New York CES do not operate as expected over their full terms, each of these plants, in addition to FitzPatrick, would be at heightened risk for early retirement, which could have a material impact on Exelon's and Generation's future financial statements. In addition, FERC's December 19, 2019 order on the MOPR in PJM may undermine the continued effectiveness of the Illinois ZES and the New Jersey ZEC program unless Illinois and New Jersey implement an FRR mechanism under which the Generation plants in these states would be removed from PJM's capacity auction. See Note 3 — Regulatory Matters for additional information on the Illinois ZES, New Jersey ZEC program, New York CES, and FERC's December 19, 2019 order on the MOPR in PJM.

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.

Generation's Dresden, Byron, and Braidwood nuclear plants in Illinois are also showing increased signs of economic distress, in a market that does not currently compensate them for their unique contribution to grid resiliency and their ability to produce large amounts of energy without carbon and air pollution. The May 2018 PJM capacity auction for the 2021-2022 planning year resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood. While all of LaSalle's capacity did clear in the 2021-2022 planning year auction, Generation has become increasingly concerned about the economic viability of this plant as well in a landscape where energy market prices remain depressed and energy market rules remain fatally flawed.

On August 27, 2020, Generation announced that it intends to permanently cease generation operations at Byron in September 2021 and at Dresden in November 2021. The current NRC licenses for Byron Units 1 and 2 expire in 2044 and 2046, respectively, and the licenses for Dresden Units 2 and 3 expire in 2029 and 2031, respectively.

As a result of the decision to early retire Byron and Dresden, Exelon and Generation recognized certain one-time charges for the year ended December 31, 2020 related to materials and supplies inventory reserve adjustments, employee-related costs, including severance benefit costs further discussed below, and construction work-in-progress impairments, among other items. In addition, as a result of the decisions to early retire Byron and Dresden, there are ongoing annual financial impacts stemming from shortening the expected economic useful lives of these nuclear plants primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and changes in ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date. See Note 10 — Asset Retirement Obligations for additional information on changes to the nuclear decommissioning ARO balance and Note 12 — Asset Impairments for impairment assessment considerations given to the Midwest asset group as a result of the early retirement decision. The total impact on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income is summarized in the table below.

Income statement expense (pre-tax)	**2020[a]**	**2019[b]**	**2018[c]**
Depreciation and amortization			
Accelerated depreciation[d]	$ 895	$ 216	$ 539
Accelerated nuclear fuel amortization	60	13	57
Operating and maintenance			
One-time charges	255	—	32
Other charges[e]	34	(53)	—
Contractual offset[f]	(364)	—	—
Total	$ 880	$ 176	$ 628

(a) Reflects expense for Byron and Dresden.
(b) Reflects expense for TMI.
(c) Reflects expense for TMI and Oyster Creek.
(d) Includes the accelerated depreciation of plant assets including any ARC.

(e) For Dresden, reflects the net impacts associated with the remeasurement of the ARO. For TMI, primarily reflects the net impacts associated with the remeasurement of the ARO. See Note 10 - Asset Retirement Obligations for additional information.

(f) Reflects contractual offset for ARO accretion, ARC depreciation, and net impacts associated with the remeasurement of the ARO. For Byron and Dresden, based on the regulatory agreement with the ICC, decommissioning-related activities in 2020 have been offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset in 2020 resulted in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. See Note 10 - Asset Retirement Obligations for additional information.

Severance benefit costs will be provided to employees impacted by the early retirements of Byron and Dresden, to the extent they are not redeployed to other nuclear plants. For the year ended December 31, 2020, Exelon and Generation recorded severance expense of $81 million within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income. The final amount of severance benefit costs will depend on the specific employees severed.

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

	Braidwood	LaSalle	Total
Asset Balances			
Materials and supplies inventory, net	$ 84	$ 106	$ 190
Nuclear fuel inventory, net	120	285	405
Completed plant, net	1,397	1,590	2,987
Construction work in progress	31	30	61
Liability Balances			
Asset retirement obligation	(570)	(954)	(1,524)
NRC License First Renewal Term	2046 (Unit 1) 2047 (Unit 2)	2042 (Unit 1) 2043 (Unit 2)	

Exelon continues to work with stakeholders on state policy solutions, while also advocating for broader market reforms at the regional and federal level. The absence of such solutions or reforms could result in future impairments of the Midwest asset group, or accelerated depreciation for specific plants over their shortened estimated useful lives, both of which could have a material unfavorable impact on Exelon's and Generation's future results of operations.

Other Generation

In March 2018, Generation notified ISO-NE of its plans to early retire, among other assets, the Mystic Generating Station's units 8 and 9 (Mystic 8 and 9) absent regulatory reforms to properly value reliability and regional fuel security. Thereafter, ISO-NE identified Mystic 8 and 9 as being needed to ensure fuel security for the region and entered into a cost of service agreement with these two units for the period between June 1, 2022 - May 31, 2024. The agreement was approved by the FERC in December 2018.

On June 10, 2020, Generation filed a complaint with FERC against ISO-NE stating that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic 8 and 9 for transmission security for the 2024 to 2025 Capacity Commitment Period (FCA 15) and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic 8 and 9 should have been filed with FERC for approval. On August 17, 2020, FERC issued an order denying the complaint. As a result, on August 20, 2020, Exelon determined that Generation will permanently cease generation operations at Mystic 8 and 9 at the expiration of the cost of service commitment in May 2024. See Note 3 — Regulatory Matters for additional discussion of Mystic's cost of service agreement.

As a result of the decision to early retire Mystic 8 and 9, Exelon and Generation recognized $22 million of one-time charges for the year ended December 31, 2020, related to materials and supplies inventory reserve adjustments, among other items. In addition, there are annual financial impacts stemming from shortening the expected economic useful life of Mystic 8 and 9 primarily related to accelerated depreciation of plant assets.

Exelon and Generation recorded incremental Depreciation and amortization expense of $26 million for the year ended December 31, 2020. See Note 12 — Asset Impairments for impairment assessment considerations of the New England Asset Group.

8. Property, Plant, and Equipment (All Registrants)

The following tables present a summary of property, plant, and equipment by asset category as of December 31, 2020 and 2019:

Asset Category	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2020									
Electric—transmission and distribution	$ 60,946	$ —	$ 29,371	$ 9,462	$ 8,797	$ 15,137	$ 10,264	$ 4,730	$ 4,568
Electric—generation	29,725	29,724	—	—	—	—	—	—	—
Gas—transportation and distribution	6,733	—	—	3,098	3,315	591	—	751	—
Common—electric and gas	2,170	—	—	956	1,138	178	—	180	—
Nuclear fuel(a)	5,399	5,399	—	—	—	—	—	—	—
Construction work in progress	3,576	450	799	474	627	1,174	824	163	182
Other property, plant, and equipment(b)	762	11	59	34	29	108	65	23	28
Total property, plant, and equipment	109,311	35,584	30,229	14,024	13,906	17,188	11,153	5,847	4,778
Less: accumulated depreciation(c)	26,727	13,370	5,672	3,843	4,034	1,811	3,697	1,533	1,303
Property, plant, and equipment, net	$ 82,584	$ 22,214	$ 24,557	$ 10,181	$ 9,872	$ 15,377	$ 7,456	$ 4,314	$ 3,475
December 31, 2019									
Electric—transmission and distribution	$ 56,809	$ —	$ 27,566	$ 8,957	$ 8,326	$ 13,809	$ 9,734	$ 4,464	$ 4,207
Electric—generation	29,839	29,839	—	—	—	—	—	—	—
Gas—transportation and distribution	6,147	—	—	2,899	2,999	525	—	690	—
Common—electric and gas	1,907	—	—	877	991	146	—	160	—
Nuclear fuel(a)	5,656	5,656	—	—	—	—	—	—	—
Construction work in progress	3,055	702	662	250	483	921	628	125	166
Other property, plant and equipment(b)	799	13	47	27	25	108	64	21	27
Total property, plant and equipment	104,212	36,210	28,275	13,010	12,824	15,509	10,426	5,460	4,400
Less: accumulated depreciation(c)	23,979	12,017	5,168	3,718	3,834	1,213	3,517	1,425	1,210
Property, plant, and equipment, net	$ 80,233	$ 24,193	$ 23,107	$ 9,292	$ 8,990	$ 14,296	$ 6,909	$ 4,035	$ 3,190

(a) Includes nuclear fuel that is in the fabrication and installation phase of $939 million and $1,025 million at December 31, 2020 and 2019, respectively.
(b) Primarily composed of land and non-utility property.
(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,774 million and $2,867 million as of December 31, 2020 and 2019, respectively.

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

	Average Service Life (years)								
Asset Category	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Electric - transmission and distribution	5-80	N/A	5-80	5-70	5-80	5-75	5-75	5-70	5-65
Electric - generation	1-58	1-58	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas - transportation and distribution	5-80	N/A	N/A	5-70	5-80	5-75	N/A	5-75	N/A
Common - electric and gas	4-75	N/A	N/A	5-55	4-50	5-75	N/A	5-75	N/A
Nuclear fuel	1-8	1-8	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other property, plant, and equipment	1-50	1-10	33-50	50	20-50	3-50	25-50	8-50	13-15

Depreciation provisions are based on the estimated useful lives of the stations, which reflect the first renewal of the operating licenses for all of Generation's operating nuclear generating stations except for Clinton, Byron, Dresden, and Peach Bottom. Clinton depreciation provisions are based on an estimated useful life through 2027, which is the last year of the Illinois ZES. Peach Bottom depreciation provisions are based on estimated useful life of 2053 and 2054 for Unit 2 and Unit 3, respectively, which reflects the second renewal of its operating licenses. Beginning August 2020, Byron, Dresden, and Mystic depreciation provisions were based on their announced shutdown dates of September 2021, November 2021, and May 2024, respectively. See Note 3 — Regulatory Matters for additional information regarding license renewals and the Illinois ZECs and Note 7 — Early Plant Retirements for additional information on the impacts of early plant retirements.

The following table presents the annual depreciation rates for each asset category. Nuclear fuel amortization is charged to fuel expense using the unit-of-production method and not included in the below table.

	Annual Depreciation Rates								
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
December 31, 2020									
Electric—transmission and distribution	2.79 %	N/A	2.95 %	2.31 %	2.69 %	2.81 %	2.53 %	2.85 %	3.08 %
Electric—generation	6.11 %	6.11 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas—transportation and distribution	2.14 %	N/A	N/A	1.85 %	2.56 %	1.50 %	N/A	1.50 %	N/A
Common—electric and gas	7.01 %	N/A	N/A	6.39 %	7.45 %	7.36 %	N/A	6.72 %	N/A
December 31, 2019									
Electric—transmission and distribution	2.80 %	N/A	2.99 %	2.36 %	2.60 %	2.77 %	2.47 %	2.86 %	2.94 %
Electric—generation	4.35 %	4.35 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas—transportation and distribution	2.04 %	N/A	N/A	1.89 %	2.30 %	1.55 %	N/A	1.55 %	N/A
Common—electric and gas	7.37 %	N/A	N/A	6.06 %	8.30 %	8.25 %	N/A	6.24 %	N/A
December 31, 2018									
Electric—transmission and distribution	2.73 %	N/A	2.95 %	2.35 %	2.61 %	2.61 %	2.40 %	2.77 %	2.45 %
Electric—generation	5.37 %	5.37 %	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Gas—transportation and distribution	2.07 %	N/A	N/A	1.90 %	2.36 %	1.59 %	N/A	1.59 %	N/A
Common—electric and gas	6.98 %	N/A	N/A	5.44 %	8.50 %	6.30 %	N/A	3.70 %	N/A

Capitalized Interest and AFUDC (All Registrants)

The following table summarizes capitalized interest and credits to AFUDC by year:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2020									
Capitalized interest	$ 22	$ 22	$ —	$ —	$ —	$ —	$ —	$ —	$ —
AFUDC debt and equity	150	—	42	23	30	55	42	6	7
December 31, 2019									
Capitalized interest	$ 24	$ 24	$ —	$ —	$ —	$ —	$ —	$ —	$ —
AFUDC debt and equity	132	—	32	17	29	54	39	6	9
December 31, 2018									
Capitalized interest	$ 31	$ 31	$ —	$ —	$ —	$ —	$ —	$ —	$ —
AFUDC debt and equity	109	—	30	12	24	44	34	4	4

See Note 1 — Significant Accounting Policies for additional information regarding property, plant and equipment policies. See Note 17 — Debt and Credit Agreements for additional information regarding Exelon's, ComEd's, PECO's, Pepco's, DPL's, and ACE's property, plant and equipment subject to mortgage liens.

9. Jointly Owned Electric Utility Plant (Exelon, Generation, PECO, DPL, and ACE)

Exelon's, Generation's, PECO's, DPL's, and ACE's material undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2020 and 2019 were as follows:

	Nuclear Generation				Transmission
	Quad Cities	Peach Bottom	Salem	Nine Mile Point Unit 2	NJ/DE[(a)]
Operator	**Generation**	**Generation**	**PSEG Nuclear**	**Generation**	**PSEG/DPL**
Ownership interest	75.00 %	50.00 %	42.59 %	82.00 %	various
Exelon's share at December 31, 2020:					
Plant in service	$ 1,188	$ 1,506	$ 717	$ 990	$ 103
Accumulated depreciation	670	601	265	187	54
Construction work in progress	13	13	39	25	—
Exelon's share at December 31, 2019:					
Plant in service	$ 1,161	$ 1,466	$ 663	$ 951	$ 102
Accumulated depreciation	627	571	249	156	53
Construction work in progress	13	21	53	27	—

(a) PECO, DPL, and ACE own a 42.55%, 1%, and 13.9% share, respectively in 151.3 miles of 500kV lines located in New Jersey and of the Salem generating plant substation. PECO, DPL, and ACE also own a 42.55%, 7.45%, and 7.45% share, respectively, in 2.5 miles of 500kV line located over the Delaware River. ACE also has a 21.78% share in a 500kV New Freedom Switching substation.

Exelon's, Generation's, PECO's, DPL's, and ACE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's, Generation's, PECO's, DPL's, and ACE's share of direct expenses of the jointly owned plants are included in Purchased power and fuel and Operating and maintenance expenses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and in Operating and maintenance expenses in PECO's, PHI's, DPL's, and ACE's Consolidated Statements of Operations and Comprehensive Income.

10. Asset Retirement Obligations (All Registrants)

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

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. Generation began decommissioning the TMI nuclear plant upon permanently ceasing operations in 2019. See below section for decommissioning of Zion Station.

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 January 1, 2019 to December 31, 2020:

Nuclear decommissioning ARO at January 1, 2019	$	10,005
Net increase due to changes in, and timing of, estimated future cash flows		864
Sale of Oyster Creek		(755)
Accretion expense		479
Costs incurred related to decommissioning plants		(89)
Nuclear decommissioning ARO at December 31, 2019[(a)]		10,504
Net increase due to changes in, and timing of, estimated future cash flows		1,022
Accretion Expense		489
Costs incurred related to decommissioning plants		(93)
Nuclear decommissioning ARO at December 31, 2020[(a)]	$	11,922

(a) Includes $80 million and $112 million as the current portion of the ARO at December 31, 2020 and 2019, respectively, which is included in Other current liabilities in Exelon's and Generation's Consolidated Balance Sheets.

The net $1,022 million increase in the ARO during 2020 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year. These adjustments primarily include:

- A net increase of approximately $800 million was driven by updates to Byron and Dresden reflecting changes in assumed retirement dates and assumed methods of decommissioning as a result of the announcement to early retire these plants in 2021. Refer to Note 7 — Early Plant Retirements for additional information.
- An increase of approximately $360 million resulting from the change in the assumed DOE spent fuel acceptance date for disposal from 2030 to 2035.
- A decrease of approximately $220 million due to lower estimated decommissioning costs primarily for Limerick and Peach Bottom nuclear units resulting from the completion of updated cost studies.

The 2020 ARO updates resulted in a increase of $60 million in Operating and maintenance expense for the year ended December 31, 2020 within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

The net $864 million increase in the ARO during 2019 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year, some with offsetting impacts. These adjustments primarily include:

- An increase of approximately $780 million for changes in the assumed retirement timing probabilities for sites including certain economically challenged nuclear plants and the extension of Peach Bottom’s operating life.
- An increase of approximately $490 million for other impacts that included updated cost escalation rates, primarily for labor, equipment and materials, and current discount rates.
- Lower estimated costs to decommission TMI, Nine Mile Point, Ginna, Braidwood, Byron, and LaSalle nuclear units of approximately $410 million resulting from the completion of updated cost studies.

The 2019 ARO updates resulted in a decrease of $150 million in Operating and maintenance expense for the year ended December 31, 2019 within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 7 — Early Plant Retirements for additional information regarding TMI and economically challenged nuclear plants and Note 3 — Regulatory Matters regarding the Peach Bottom second license renewal.

NDT Funds

NDT funds have been established for each generation station unit to satisfy Generation’s nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO’s calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. On March 31, 2017, PECO filed its Nuclear Decommissioning Cost Adjustment with the PAPUC proposing an annual recovery from customers of approximately $4 million. This amount reflects a decrease from the previously approved annual collection of approximately $24 million primarily due to the removal of the collections for Limerick Units 1 and 2 as a result of the NRC approving the extension of the operating licenses for an additional 20 years. On August 8, 2017, the PAPUC approved the filing and the new rates became effective January 1, 2018.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from utility customers for any of Generation's other nuclear units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd’s or PECO’s customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to Generation's other nuclear units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to NDT funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At December 31, 2020 and 2019, Exelon and Generation had NDT funds totaling $14,599 million and $13,353 million, respectively. The NDT funds include $134 million and $163 million for the current portion of the NDT at December 31, 2020 and 2019, respectively, which are included in Other current assets in Exelon's and Generation's Consolidated Balance Sheets. See Note 24 — Supplemental Financial Information for additional information on activities of the NDT funds.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

Based on the regulatory agreements with the ICC and PAPUC that dictate Generation’s obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis and the former PECO units in total, decommissioning-related activities net of applicable taxes, including realized and unrealized gains and losses on the NDT funds, depreciation of the ARC, and accretion of the decommissioning obligation, are generally offset within Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income and are recorded by Generation and the corresponding regulated utility as a component of the intercompany and regulatory balances on the balance sheet. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

For the former PECO units, given the symmetric settlement provisions that allow for continued recovery of decommissioning costs from PECO customers in the event of a shortfall and the obligation for Generation to ultimately return any excess funds to PECO customers (on an aggregate basis for all seven units), decommissioning-related activities are generally offset within Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income regardless of whether the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables or noncurrent receivables to affiliates at Generation with PECO recording an equal noncurrent affiliate receivable from or payable to Generation and a corresponding regulatory liability or regulatory asset. Any changes to the existing PECO regulatory agreements could impact Exelon’s and Generation’s ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon’s and Generation’s financial statements could be material.

For the former ComEd units, given no further recovery from ComEd customers is permitted and Generation retains an obligation to ultimately return any unused NDTs to ComEd customers (on a unit-by-unit basis), to the extent the related NDT investment balances are expected to exceed the total estimated decommissioning obligation for each unit, the offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results with Generation recognizing an intercompany payable to ComEd while ComEd records an intercompany receivable from Generation with a corresponding regulatory liability. However, given the asymmetric settlement provision that does not allow for continued recovery from ComEd customers in the event of a shortfall, recognition of a regulatory asset at ComEd is not permissible and accounting for decommissioning-related activities at Generation for that unit would not be offset, and the impact to Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income could be material during such periods.

As of December 31, 2020, decommissioning-related activities for all of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are currently offset within Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

See Note 3 — Regulatory Matters and Note 25 — Related Party Transactions for additional information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd, and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

In 2010, Generation completed an ASA under which ZionSolutions assumed responsibility for decommissioning Zion Station and Generation transferred to ZionSolutions substantially all the Zion Station's assets, including the related NDT funds.

Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility.

Generation had retained its obligation for the SNF as well as certain NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. As of December 31, 2020, the ARO associated with Zion's SNF storage facility is $ 175 million and the NDT funds available to fund this obligation are $66 million.

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. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded in Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2020 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2020 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain LLRW); (3) the consideration of multiple scenarios where decommissioning and site restoration activities, as applicable, are completed under possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the consideration of multiple end of life scenarios; (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 4% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.6% to 6.1% (as compared to a historical 5-year annual average pre-tax return of approximately 9.0%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial positions may be significantly adversely affected.

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.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2021. This report will reflect the status of decommissioning funding assurance as of December 31, 2020 and will include the 2021 early retirements of Byron and Dresden. A shortfall could require Exelon to post parental guarantee for Generation's share of the funding assurance. However, the amount of any required guarantee will ultimately depend on the decommissioning approach adopted at Byron and Dresden, the associated level of costs, and the decommissioning trust fund investment performance going forward.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations (All Registrants)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. The Utility Registrants have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1 — Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected in the Registrants' Consolidated Balance Sheets from January 1, 2019 to December 31, 2020:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Non-nuclear AROs at January 1, 2019	$ 471	$ 238	$ 121	$ 28	$ 25	$ 52	$ 37	$ 11	$ 4
Net increase (decrease) due to changes in, and timing of, estimated future cash flows	17	7	8	—	(2)	4	3	1	—
Development projects	2	2	—	—	—	—	—	—	—
Accretion expense[(a)]	16	12	1	1	1	1	1	—	—
Asset divestitures	(42)	(42)	—	—	—	—	—	—	—
Payments	(4)	(1)	(1)	(1)	(1)	—	—	—	—
Non-nuclear AROs at December 31, 2019	460	216	129	28	23	57	41	12	4
Net increase (decrease) due to changes in, and timing of, estimated future cash flows	7	2	—	2	1	1	(3)	2	2
Development projects	1	1	—	—	—	—	—	—	—
Accretion expense[(a)]	16	11	1	1	1	1	1	—	—
Asset divestitures	(4)	(4)	—	—	—	—	—	—	—
Payments	(9)	(4)	(1)	(2)	(2)	—	—	—	—
AROs reclassified to liabilities held for sale[(b)]	(10)	(10)	—	—	—	—	—	—	—
Non-nuclear AROs at December 31, 2020	$ 461	$ 212	$ 129	$ 29	$ 23	$ 59	$ 39	$ 14	$ 6

(a) For ComEd, PECO, BGE, PHI, Pepco, and DPL, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(b) Represents AROs related to Generation's solar business, which were classified as held for sale as a result of the sale agreement. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

11. Leases (All Registrants)

Lessee

The Registrants have operating and finance leases for which they are the lessees. The following tables outline the significant types of leases at each registrant and other terms and conditions of the lease agreements as of December 31, 2020. Exelon, Generation, ComEd, PECO, and BGE did not have material finance leases in 2020 or in 2019. PHI, Pepco, DPL, and ACE also did not have material finance leases in 2019.

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Contracted generation	●	●							
Real estate	●	●	●	●	●	●	●	●	●
Vehicles and equipment	●	●	●	●	●	●	●	●	●

(in years)	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Remaining lease terms	1-85	1-35	1-4	1-13	1-85	1-11	1-11	1-11	1-7
Options to extend the term	2-30	2-30	5	N/A	N/A	3-30	5	3-30	5
Options to terminate within	1-12	1-4	2	N/A	1	N/A	N/A	N/A	N/A

The components of operating lease costs were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020									
Operating lease costs	$ 292	$ 194	$ 3	$ 1	$ 33	$ 46	$ 11	$ 13	$ 6
Variable lease costs	241	234	1	—	1	2	1	1	—
Short-term lease costs	2	2	—	—	—	—	—	—	—
Total lease costs [(a)]	$ 535	$ 430	$ 4	$ 1	$ 34	$ 48	$ 12	$ 14	$ 6
For the year ended December 31, 2019									
Operating lease costs	$ 320	$ 222	$ 3	$ 1	$ 33	$ 48	$ 12	$ 14	$ 7
Variable lease costs	300	282	2	—	2	6	2	2	1
Short-term lease costs	19	19	—	—	—	—	—	—	—
Total lease costs [(a)]	$ 639	$ 523	$ 5	$ 1	$ 35	$ 54	$ 14	$ 16	$ 8

(a) Excludes $48 million, $44 million, $4 million, and $4 million of sublease income recorded at Exelon, Generation, PHI, and DPL, respectively, for the year ended December 31, 2020 and $51 million, $44 million, $7 million, and $7 million of sublease income recorded at Exelon, Generation, PHI, and DPL, respectively, for the year ended December 31, 2019.

PHI, Pepco, DPL, and ACE recorded finance lease costs of $9 million, $3 million, $4 million, and $2 million, respectively, for the year ended December 31, 2020.

The following table presents the Registrants' rental expense under the prior lease accounting guidance for the year ended December 31, 2018:

	Exelon	Generation[(a)]	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rent expense	$ 670	$ 558	$ 7	$ 10	$ 35	$ 48	$ 10	$ 13	$ 8

(a) Includes contingent operating lease payments associated with contracted generation agreements that are not included in the minimum future operating lease payments table. Payments made under Generation's contracted generation lease agreements totaled $493 million.

The following tables provide additional information regarding the presentation of operating and finance lease ROU assets and lease liabilities within the Registrants' Consolidated Balance Sheets:

	Operating Leases								
	Exelon[(a)]	Generation[(a)]	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
As of December 31, 2020									
Operating lease ROU assets									
Other deferred debits and other assets	$ 1,064	$ 726	$ 7	$ 1	$ 46	$ 241	$ 49	$ 54	$ 15
Operating lease liabilities									
Other current liabilities	213	132	3	—	45	31	6	9	4
Other deferred credits and other liabilities	1,089	775	5	1	19	224	46	56	11
Total operating lease liabilities	$ 1,302	$ 907	$ 8	$ 1	$ 64	$ 255	$ 52	$ 65	$ 15
As of December 31, 2019									
Operating lease ROU assets									
Other deferred debits and other assets	$ 1,305	$ 895	$ 9	$ 2	$ 77	$ 273	$ 56	$ 63	$ 18
Operating lease liabilities									
Other current liabilities	225	157	3	—	32	31	6	9	4
Other deferred credits and other liabilities	1,307	925	8	1	50	254	51	65	14
Total operating lease liabilities	$ 1,532	$ 1,082	$ 11	$ 1	$ 82	$ 285	$ 57	$ 74	$ 18

(a) Exelon's and Generation's operating ROU assets and lease liabilities include $387 million and $528 million, respectively, related to contracted generation as of December 31, 2020, and $515 million and $664 million, respectively, as of December 31, 2019.

	Finance Leases			
	PHI	Pepco	DPL	ACE
As of December 31, 2020				
Finance lease ROU assets				
Plant, property and equipment, net	$ 50	$ 17	$ 20	$ 13
Finance lease liabilities				
Long-term debt due within one year	7	2	3	2
Long-term debt	43	15	17	11
Total finance lease liabilities	$ 50	$ 17	$ 20	$ 13

The weighted average remaining lease terms, in years, for operating and finance leases were as follows:

	Operating Leases								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
As of December 31, 2020	10.1	10.5	3.8	4.2	8.3	8.2	9.1	9.1	4.0
As of December 31, 2019	10.1	10.6	4.6	4.4	5.4	9.0	9.8	9.7	4.7

	Finance Leases			
	PHI	Pepco	DPL	ACE
As of December 31, 2020	6.5	6.3	6.5	6.5

The weighted average discount rates for operating and finance leases were as follows:

	Operating Leases								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
As of December 31, 2020	4.7 %	4.9 %	3.0 %	2.9 %	3.8 %	4.2 %	4.0 %	4.0 %	3.5 %
As of December 31, 2019	4.6 %	4.8 %	3.0 %	3.2 %	3.6 %	4.2 %	4.0 %	4.0 %	3.6 %

	Finance Leases			
	PHI	Pepco	DPL	ACE
As of December 31, 2020	2.5 %	2.6 %	2.4 %	2.4 %

Future minimum lease payments for operating and finance leases as of December 31, 2020 were as follows:

	Operating Leases								
Year	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2021	$ 239	$ 145	$ 3	$ 1	$ 46	$ 40	$ 8	$ 11	$ 5
2022	177	113	2	—	16	39	8	10	4
2023	146	100	1	—	1	38	7	9	3
2024	141	98	1	—	—	36	6	8	2
2025	140	99	1	—	—	33	6	7	2
Remaining years	834	640	—	—	18	120	28	35	—
Total	1,677	1,195	8	1	81	306	63	80	16
Interest	375	288	—	—	17	51	11	15	1
Total operating lease liabilities	$ 1,302	$ 907	$ 8	$ 1	$ 64	$ 255	$ 52	$ 65	$ 15

	Finance Leases			
Year	PHI	Pepco	DPL	ACE
2021	$ 8	$ 3	$ 3	$ 2
2022	8	3	3	2
2023	8	3	3	2
2024	8	3	3	2
2025	8	3	3	2
Remaining years	13	3	6	4
Total	53	18	21	14
Interest	3	1	1	1
Total finance lease liabilities	$ 50	$ 17	$ 20	$ 13

Cash paid for amounts included in the measurement of operating and finance lease liabilities were as follows:

	Operating cash flows from operating leases								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020	$ 271	$ 204	$ 3	$ 1	$ 20	$ 39	$ 8	$ 9	$ 4
For the year ended December 31, 2019	287	206	3	—	33	37	9	6	5

	Financing cash flows from finance leases			
	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020	$ 6	$ 2	$ 3	$ 1

ROU assets obtained in exchange for operating and finance lease obligations were as follows:

	Operating Leases								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020	$ 1	$ 3	$ —	$ 1	$ —	$ (1)	$ —	$ (1)	$ —
For the year ended December 31, 2019	52	14	6	—	2	(3)	(1)	(2)	(1)

	Finance Leases			
	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020	$ 29	$ 8	$ 14	$ 7

Lessor

The Registrants have operating leases for which they are the lessors. The following tables outline the significant types of leases at each registrant and other terms and conditions of their lease agreements as of December 31, 2020.

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Contracted generation	●	●							
Real estate	●	●	●	●	●	●	●	●	●

(in years)	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Remaining lease terms	1-82	1-31	1-16	1-82	22	1-12	1-5	11-12	1
Options to extend the term	1-79	1-5	5-79	5-50	N/A	5	N/A	N/A	N/A

The components of lease income were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020									
Operating lease income	$ 52	$ 47	$ —	$ —	$ —	$ 3	$ —	$ 3	$ —
Variable lease income	283	282	—	—	—	1	—	1	—
For the year ended December 31, 2019									
Operating lease income	$ 54	$ 47	$ —	$ —	$ —	$ 5	$ —	$ 4	$ —
Variable lease income	261	258	—	—	—	3	—	3	—

Future minimum lease payments to be recovered under operating leases as of December 31, 2020 were as follows:

Year	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2021	$ 51	$ 45	$ —	$ —	$ —	$ 4	$ 1	$ 3	$ —
2022	50	45	—	—	—	4	—	3	—
2023	49	45	—	—	—	4	—	4	—
2024	49	45	—	—	—	3	—	3	—
2025	48	45	—	—	—	4	—	4	—
Remaining years	217	182	1	4	1	31	—	31	—
Total	$ 464	$ 407	$ 1	$ 4	$ 1	$ 50	$ 1	$ 48	$ —

12. 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 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 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.

The United States Bankruptcy Court entered an order on June 20, 2020 confirming PG&E’s plan of reorganization. On July 1, 2020 the plan became effective, and PG&E emerged from bankruptcy. Under the confirmed plan, PG&E will continue to honor the existing PPA agreement with Antelope Valley.

See Note 17 - Debt and Credit Agreements for additional information.

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 grid operator ISO-NE of its plans to early retire its Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. These events suggested that the carrying value of the New England asset group may be impaired. In the first 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.

In the third quarter of 2020, in conjunction with the retirement announcement of Mystic Units 8 and 9, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the estimated undiscounted future cash flows and fair value of the New England asset group were less than their carrying values. As a result, a pre-tax impairment charge of $500 million was recorded in the third quarter of 2020 within Operating and maintenance expense in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income. See Note 7 - Early Plant Retirements for additional information.

Midwest Asset Group

In the third quarter of 2020, in conjunction with the retirement announcements of the Byron and Dresden nuclear plants, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the Midwest asset group and no impairment charge was required.

Generation will continue to monitor the recoverability of the carrying value of the Midwest asset group as certain other nuclear plants in Illinois are also showing increased signs of economic distress, which could lead to an early retirement. See Note 7 - Early Plant Retirements for additional information.

Equity Method Investments in Certain Distributed Energy Companies

In the third quarter of 2019, Generation’s equity method investments in certain distributed energy companies were fully impaired due to an other-than-temporary decline in market conditions and underperforming projects.

Exelon and Generation recorded a pre-tax impairment charge of $164 million in Equity in losses of unconsolidated affiliates and an offsetting pre-tax $96 million in Net income attributable to noncontrolling interests in their Consolidated Statements of Operations and Comprehensive Income. As a result, Generation accelerated the amortization of investment tax credits associated with these companies and Exelon and Generation recorded a benefit of $46 million in Income taxes. The impairment charge and the accelerated amortization of investment tax credits resulted in a net $15 million decrease to Exelon's and Generation's earnings. See Note 23 — Variable Interest Entities for additional information.

13. Intangible Assets (Exelon, Generation, ComEd, PHI, Pepco, DPL, and ACE)

Goodwill

The following table presents the gross amount, accumulated impairment loss, and carrying amount of goodwill at Exelon, ComEd, and PHI as of December 31, 2020 and 2019. There were no additions or impairments during the years ended December 31, 2020 and 2019.

	Gross Amount	Accumulated Impairment Loss	Carrying Amount
Exelon	$ 8,660	$ 1,983	$ 6,677
ComEd[(a)]	4,608	1,983	2,625
PHI[(b)]	4,005	—	4,005

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom merger (predecessor parent company of ComEd).
(b) Reflects goodwill recorded in 2016 from the PHI merger.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of ComEd's and PHI's reporting units below their carrying amounts. A reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is assessed for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. ComEd has a single operating segment. PHI's operating segments are Pepco, DPL, and ACE. See Note 5 — Segment Information for additional information. There is no level below these operating segments for which operating results are regularly reviewed by segment management. Therefore, the ComEd, Pepco, DPL, and ACE operating segments are also considered reporting units for goodwill impairment assessment purposes. Exelon's and ComEd's $2.6 billion of goodwill has been assigned entirely to the ComEd reporting unit, while Exelon's and PHI's $4.0 billion of goodwill has been assigned to the Pepco, DPL, and ACE reporting units in the amounts of $2.1 billion, $1.4 billion, and $0.5 billion, respectively.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. As part of the qualitative assessments, Exelon, ComEd, and PHI evaluate, among other things, management's best estimate of projected operating and capital cash flows for their businesses, outcomes of recent regulatory proceedings, changes in certain market conditions, including the discount rate and regulated utility peer EBITDA multiples, and the passing margin from their last quantitative assessments performed. If an entity bypasses the qualitative assessment, a quantitative, fair value-based assessment is performed, which compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the entity recognizes an impairment charge, which is limited to the amount of goodwill allocated to the reporting unit.

Application of the goodwill impairment assessment requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's, Pepco's, DPL's, and ACE's businesses, and the fair value of debt.

2020 and 2019 Goodwill Impairment Assessment. ComEd and PHI qualitatively determined that it was more likely than not that the fair values of their reporting units exceeded their carrying values and, therefore, did not perform quantitative assessments as of November 1, 2020 and 2019 for ComEd and PHI. The last quantitative assessments performed were as of November 1, 2016 for ComEd and November 1, 2018 for PHI.

While the annual assessments indicated no impairments, certain assumptions used to estimate reporting unit fair values are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon's, ComEd's, and PHI's goodwill, which could be material.

Other Intangible Assets and Liabilities

Exelon's, Generation's, ComEd's, and PHI's other intangible assets and liabilities, included in Unamortized energy contract assets and liabilities and Other deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2020 and 2019. The intangible assets and liabilities shown below are amortized on a straight line basis, except for unamortized energy contracts which are amortized in relation to the expected realization of the underlying cash flows:

	December 31, 2020			December 31, 2019		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Generation						
Unamortized Energy Contracts	$ 1,963	$ (1,642)	$ 321	$ 1,967	$ (1,612)	$ 355
Customer Relationships	326	(215)	111	343	(190)	153
Trade Name	222	(197)	25	243	(193)	50
ComEd						
Chicago Settlement Agreements	162	(162)	—	162	(155)	7
PHI						
Unamortized Energy Contracts	(1,515)	1,188	(327)	(1,515)	1,073	(442)
Exelon Corporate						
Software License	95	(53)	42	95	(44)	51
Exelon	$ 1,253	$ (1,081)	$ 172	$ 1,295	$ (1,121)	$ 174

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2020, 2019, and 2018:

For the Years Ended December 31,	Exelon[a][b]	Generation[a]	ComEd	PHI[b]
2020	$ (17)	$ 81	$ 7	$ (115)
2019	(28)	74	7	(119)
2018	(109)	63	7	(188)

(a) At Exelon and Generation, amortization of unamortized energy contracts totaling $30 million, $21 million, and $14 million for the years ended December 31, 2020, 2019, and 2018, respectively, was recorded in Operating revenues or Purchased power and fuel expense in their Consolidated Statements of Operations and Comprehensive Income.

(b) At Exelon and PHI, amortization of the unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchased power and fuel expense in their Consolidated Statements of Operations and Comprehensive Income.

The following table summarizes the estimated future amortization expense related to intangible assets and liabilities as of December 31, 2020:

For the Years Ending December 31,	Exelon	Generation	PHI
2021	$ (1)	$ 81	$ (92)
2022	(22)	57	(89)
2023	(20)	51	(81)
2024	20	48	(38)
2025	40	41	(5)

Renewable Energy Credits (Exelon and Generation)

Exelon's and Generation's RECs are included in Other current assets and Other deferred debits and other assets in the Consolidated Balance Sheets. Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Generally, revenue for RECs that are sold to a counterparty under a contract that specifically identifies a power plant is recognized at a point in time when the power is produced. This includes both bundled and unbundled REC sales. Otherwise, the revenue is recognized upon physical transfer of the REC to the customer.

The following table presents the current and noncurrent RECs as of December 31, 2020 and 2019:

	As of December 31, 2020		As of December 31, 2019	
	Exelon	Generation	Exelon	Generation
Current REC's	$ 632	$ 621	$ 345	$ 336
Noncurrent REC's	—	—	86	86

14. Income Taxes (All Registrants)

Components of Income Tax Expense or Benefit

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

	For the Year Ended December 31, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:									
Federal									
Current	$ 26	$ 130	$ (24)	$ (7)	$ 4	$ 25	$ 40	$ (13)	$ (4)
Deferred	156	150	112	1	10	(129)	(62)	(20)	(43)
Investment tax credit amortization	(28)	(25)	(2)	—	—	(1)	—	—	—
State									
Current	42	40	(27)	—	—	(5)	—	—	—
Deferred	177	(46)	118	(24)	27	33	15	8	6
Total	$ 373	$ 249	$ 177	$ (30)	$ 41	$ (77)	$ (7)	$ (25)	$ (41)

	For the Year Ended December 31, 2019								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:									
Federal									
Current	$ 85	$ 147	$ 59	$ 45	$ (51)	$ 43	$ 16	$ 29	$ (3)
Deferred	489	346	15	20	95	(34)	(6)	(21)	(6)
Investment tax credit amortization	(72)	(69)	(2)	—	—	(1)	—	—	—
State									
Current	5	10	(5)	—	—	3	—	—	—
Deferred	267	82	96	—	35	27	6	14	9
Total	$ 774	$ 516	$ 163	$ 65	$ 79	$ 38	$ 16	$ 22	$ —

	For the Year Ended December 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:									
Federal									
Current	$ 226	$ 337	$ (63)	$ 11	$ (5)	$ (4)	$ 28	$ (3)	$ (14)
Deferred	(99)	(347)	145	10	47	23	(22)	13	18
Investment tax credit amortization	(24)	(21)	(2)	—	—	(1)	—	—	—
State									
Current	(1)	6	(29)	1	—	7	—	—	—
Deferred	16	(83)	117	(16)	32	8	5	12	8
Total	$ 118	$ (108)	$ 168	$ 6	$ 74	$ 33	$ 11	$ 22	$ 12

Rate Reconciliation

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

	For the Year Ended December 31, 2020[a]								
	Exelon	Generation	ComEd[b]	PECO[c]	BGE[d]	PHI[d]	Pepco[d]	DPL[d]	ACE[d]
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	7.8	0.5	11.6	(4.5)	5.5	5.1	4.5	6.6	7.0
Qualified NDT fund income	8.4	23.5	—	—	—	—	—	—	—
Deferred Prosecution Agreement payments	1.8	—	6.8	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.1)	(2.6)	(0.3)	—	(0.1)	(0.2)	(0.1)	(0.3)	(0.5)
Plant basis differences	(4.0)	—	(0.6)	(18.7)	(1.5)	(1.6)	(1.7)	(0.4)	(3.0)
Production tax credits and other credits	(2.2)	(5.4)	(0.3)	—	(0.4)	(0.3)	(0.3)	(0.3)	(0.5)
Noncontrolling interests	1.1	3.2	—	—	—	—	—	—	—
Excess deferred tax amortization	(13.6)	—	(11.2)	(4.6)	(13.9)	(42.0)	(25.4)	(51.7)	(82.1)
Tax settlements	(3.7)	(10.3)	—	—	—	—	—	—	—
Other	0.5	(0.1)	1.8	(0.4)	(0.1)	(0.4)	(0.7)	0.1	0.4
Effective income tax rate	16.0 %	29.8 %	28.8 %	(7.2)%	10.5 %	(18.4)%	(2.7)%	(25.0)%	(57.7)%

	For the Year Ended December 31, 2019[a]								
	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	5.4	3.8	8.5	—	6.4	4.7	2.0	6.8	7.0
Qualified NDT fund income	5.9	12.3	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.5)	(3.0)	(0.2)	—	(0.1)	(0.2)	(0.1)	(0.2)	(0.3)
Plant basis differences	(1.4)	—	—	(7.2)	(1.2)	(1.2)	(1.8)	(0.4)	(0.7)
Production tax credits and other credits	(3.1)	(4.8)	(1.2)	—	(1.3)	(0.2)	(0.1)	—	(0.1)
Noncontrolling interests	(0.6)	(1.2)	—	—	—	—	—	—	—
Excess deferred tax amortization	(5.5)	—	(9.7)	(2.8)	(6.8)	(17.5)	(15.1)	(14.2)	(27.0)
Other	(0.8)	(1.2)	0.8	—	—	0.8	0.3	—	0.1
Effective income tax rate	19.4 %	26.9 %	19.2 %	11.0 %	18.0 %	7.4 %	6.2 %	13.0 %	— %

	For the Year Ended December 31, 2018[a]								
	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	0.5	(16.6)	8.3	(2.6)	6.6	2.9	2.0	6.7	7.4
Qualified NDT fund income	(1.9)	(11.8)	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.2)	(6.5)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.3)	(0.4)
Plant basis differences	(3.5)	—	(0.2)	(14.1)	(1.3)	(1.6)	(2.8)	(0.3)	(0.5)
Production tax credits and other credits	(2.2)	(13.5)	—	—	—	—	—	—	—
Noncontrolling interests	(1.0)	(6.1)	—	—	—	—	—	—	—
Excess deferred tax amortization	(8.3)	—	(9.1)	(3.2)	(8.0)	(14.8)	(15.3)	(12.0)	(14.9)
Tax Cuts and Jobs Act of 2017	0.9	2.7	(0.1)	—	—	0.1	—	—	—
Other	1.0	1.3	0.5	0.3	0.9	0.4	0.3	0.4	1.2
Effective income tax rate	5.3 %	(29.5) %	20.2 %	1.3 %	19.1 %	7.8 %	5.1 %	15.5 %	13.8 %

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

(b) At ComEd, the higher effective tax rate is primarily related to the nondeductible Deferred Prosecution Agreement payments. See Note 19 — Commitments and Contingencies for additional information.

(c) At PECO, the negative effective tax rate is primarily related to an increase in plant basis differences attributable to tax repair deductions related to an increase in storms and qualifying projects.

(d) At BGE, the lower effective tax rate, and at PHI, Pepco, DPL, and ACE, the negative effective tax rate is primarily attributable to accelerated amortization of transmission related income tax regulatory liabilities as a result of regulatory settlements. See Note 3 — Regulatory Matters for additional information.

Tax Differences and Carryforwards

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2020 and 2019 are presented below:

	As of December 31, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Plant basis differences	$ (13,868)	$ (2,592)	$ (4,432)	$ (2,131)	$ (1,711)	$ (2,822)	$ (1,259)	$ (806)	$ (725)
Accrual based contracts	40	(37)	—	—	—	77	—	—	—
Derivatives and other financial instruments	41	(41)	84	—	—	2	—	—	—
Deferred pension and postretirement obligation	1,559	(236)	(288)	(30)	(33)	(80)	(74)	(40)	(7)
Nuclear decommissioning activities	(742)	(742)	—	—	—	—	—	—	—
Deferred debt refinancing costs	169	16	(6)	—	(2)	131	(3)	(1)	(1)
Regulatory assets and liabilities	(1,107)	—	87	(231)	142	(41)	38	67	46
Tax loss carryforward	286	55	—	47	57	90	4	49	38
Tax credit carryforward	841	838	—	—	—	—	—	—	—
Investment in partnerships	(835)	(813)	—	—	—	—	—	—	—
Other, net	1,070	347	223	104	29	220	107	18	27
Deferred income tax liabilities (net)	$ (12,546)	$ (3,205)	$ (4,332)	$ (2,241)	$ (1,518)	$ (2,423)	$ (1,187)	$ (713)	$ (622)
Unamortized investment tax credits[(a)]	(464)	(445)	(9)	(1)	(3)	(6)	(2)	(2)	(3)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (13,010)	$ (3,650)	$ (4,341)	$ (2,242)	$ (1,521)	$ (2,429)	$ (1,189)	$ (715)	$ (625)

(a) Does not include unamortized investment tax credits reclassified to liabilities held for sale.

	As of December 31, 2019								
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Plant basis differences	$ (13,413)	$ (2,814)	$ (4,197)	$ (1,978)	$ (1,578)	$ (2,681)	$ (1,204)	$ (753)	$ (687)
Accrual based contracts	61	(43)	—	—	—	104	—	—	—
Derivatives and other financial instruments	165	88	84	—	—	2	—	—	—
Deferred pension and postretirement obligation	1,504	(220)	(270)	(28)	(28)	(89)	(75)	(42)	(10)
Nuclear decommissioning activities	(503)	(503)	—	—	—	—	—	—	—
Deferred debt refinancing costs	183	20	(7)	—	(3)	142	(3)	(2)	(1)
Regulatory assets and liabilities	(884)	—	183	(169)	157	(10)	55	88	77
Tax loss carryforward	240	55	—	25	49	93	13	44	31
Tax credit carryforward	892	897	—	—	—	—	—	—	—
Investment in partnerships	(830)	(808)	—	—	—	—	—	—	—
Other, net	926	236	196	70	10	181	85	12	16
Deferred income tax liabilities (net)	$ (11,659)	$ (3,092)	$ (4,011)	$ (2,080)	$ (1,393)	$ (2,258)	$ (1,129)	$ (653)	$ (574)
Unamortized investment tax credits	(668)	(648)	(10)	(1)	(3)	(7)	(2)	(2)	(3)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (12,327)	$ (3,740)	$ (4,021)	$ (2,081)	$ (1,396)	$ (2,265)	$ (1,131)	$ (655)	$ (577)

The following table provides Exelon’s, Generation’s, PECO’s, BGE’s, PHI’s, Pepco’s, DPL’s, and ACE’s carryforwards, which are presented on a post-apportioned basis, and any corresponding valuation allowances as of December 31, 2020. ComEd does not have net operating losses or credit carryforwards for the year ended December 31, 2020.

	Exelon	**Generation**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Federal								
Federal general business credits carryforwards and other carryforwards	$ 858	$ 852	$ —	$ —	$ —	$ —	$ —	$ —
State								
State net operating losses and other carryforwards	5,202	1,118	616	902	1,436	63	728	531
Deferred taxes on state tax attributes (net)	324	76	49	59	98	4	49	38
Valuation allowance on state tax attributes	27	23	1	—	—	—	—	—
Year in which net operating loss or credit carryforwards will begin to expire[(a)]	2034	2034	2032	2033	2029	2029	2032	2031

(a) Generation's state net operating loss carryforwards will begin expiring in 2029. PECO's Pennsylvania charitable contribution carryforwards and BGE's Maryland charitable deduction and capital loss carryforwards will begin expiring in 2021. ACE's New Jersey tax credit carryforward has an indefinite carryforward period. These amounts are not material.

Tabular Reconciliation of Unrecognized Tax Benefits

The following table presents changes in unrecognized tax benefits, by Registrant.

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at January 1, 2018	$ 743	$ 468	$ 2	$ —	$ 120	$ 125	$ 59	$ 21	$ 14
Change to positions that only affect timing	15	15	—	—	—	—	—	—	—
Increases based on tax positions prior to 2018	30	21	—	—	—	8	7	1	—
Decreases based on tax positions prior to 2018(a)	(251)	(36)	—	—	(120)	(88)	(66)	(22)	—
Decrease from settlements with taxing authorities	(53)	(53)	—	—	—	—	—	—	—
Decreases from expiration of statute of limitations	(7)	(7)	—	—	—	—	—	—	—
Balance at December 31, 2018	477	408	2	—	—	45	—	—	14
Change to positions that only affect timing	26	12	3	1	4	3	2	1	—
Increases based on tax positions related to 2019	2	1	—	—	—	—	—	—	—
Increases based on tax positions prior to 2019	34	19	3	2	3	—	—	—	—
Decreases based on tax positions prior to 2019	(3)	(3)	—	—	—	—	—	—	—
Decrease from settlements with taxing authorities	(29)	4	(2)	—	—	—	—	—	—
Balance at December 31, 2019	507	441	6	3	7	48	2	1	14
Change to positions that only affect timing	6	—	2	3	3	3	1	—	1
Increases based on tax positions related to 2020	3	1	—	—	—	—	—	—	—
Increases based on tax positions prior to 2020	26	23	1	—	—	1	—	—	—
Decreases based on tax positions prior to 2020(b)	(348)	(346)	—	—	—	—	—	—	—
Decrease from settlements with taxing authorities(b)	(69)	(69)	—	—	—	—	—	—	—
Balance at December 31, 2020	$ 125	$ 50	$ 9	$ 6	$ 10	$ 52	$ 3	$ 1	$ 15

(a) Exelon, Generation, BGE, PHI, Pepco, and DPL decreased their unrecognized state tax benefits primarily 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 BGE, PHI, Pepco, and DPL was offset by corresponding regulatory liabilities and that portion had no immediate impact to their effective tax rate.

(b) 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, in the first quarter of 2020, reflecting a decrease to Exelon's and Generation's income tax expense of $67 million.

Like-Kind Exchange

In 2016, the Tax Court held that Exelon was not entitled to defer a gain on its 1999 like-kind exchange transaction. In addition to the tax and interest related to the gain deferral, the Tax Court also ruled that Exelon was liable for penalties and interest on the penalties. Exelon had fully paid the amounts assessed resulting from the Tax Court decision in 2017. In September 2017, Exelon appealed the Tax Court decision to the U.S. Court of Appeals for the Seventh Circuit. In October 2018, the U.S. Court of Appeals for the Seventh Circuit affirmed the

Tax Court's decision. Exelon filed a petition seeking rehearing of the Seventh Circuit's decision, but the Seventh Circuit denied that petition in December 2018. In the first quarter of 2019, Exelon elected not to seek a further review by the U.S. Supreme Court. As a result, Exelon's and ComEd's unrecognized tax benefits decreased by approximately $33 million and $2 million, respectively, in the first quarter of 2019.

Recognition of unrecognized tax benefits

The following table presents Exelon's, Generation's, and PHI's unrecognized tax benefits that, if recognized, would decrease the effective tax rate. ComEd's, PECO's, BGE's, Pepco's, DPL's, and ACE's amounts are not material.

	Exelon	Generation	PHI[a]
December 31, 2020	$ 73	$ 39	$ 33
December 31, 2019	462	429	32
December 31, 2018	463	408	31

(a) PHI has $21 million of unrecognized state tax benefits that, if recognized, $14 million would be in the form of a net operating loss carryforward, which is expected to require a full valuation allowance based on present circumstances.

ACE has $14 million of unrecognized tax benefits as of December 31, 2020, 2019 and 2018 that, if recognized, may be included in future base rates and that portion would have no impact on the effective tax rate. Exelon's, Generation's, ComEd's, PECO's, BGE's, PHI's, Pepco's, and DPL's amounts are not material.

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

As of December 31, 2020, ACE has approximately $14 million of unrecognized state tax benefits that could significantly decrease within the 12 months after the reporting date based on the outcome of pending court cases involving other taxpayers. The unrecognized tax benefit, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Total amounts of interest and penalties recognized

The following table represents the net interest and penalties receivable (payable) related to tax positions reflected in Exelon's Consolidated Balance Sheets. Generation's and the Utility Registrants' amounts are not material.

Net interest and penalties receivable as of	Exelon
December 31, 2020	$ 314
December 31, 2019	318

The Registrants did not record material interest and penalty expense related to tax positions reflected in their Consolidated Balance Sheets. Interest expense and penalty expense are recorded in Interest expense, net and Other, net, respectively, in Other income and deductions in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Description of tax years open to assessment by major jurisdiction

Major Jurisdiction	Open Years	Registrants Impacted
Federal consolidated income tax returns[(a)]	2010-2019	All Registrants
Delaware separate corporate income tax returns	Same as federal	DPL
District of Columbia combined corporate income tax returns	2017-2019	Exelon, PHI, Pepco
Illinois unitary corporate income tax returns	2012-2019	Exelon, Generation, ComEd
Maryland separate company corporate net income tax returns	Same as federal	BGE, Pepco, DPL
New Jersey separate corporate income tax returns	2013-2019	Exelon, Generation
New Jersey separate corporate income tax returns	2014-2019	ACE
New York combined corporate income tax returns	2010-March 2012	Exelon, Generation
New York combined corporate income tax returns	2011-2019	Exelon, Generation
Pennsylvania separate corporate income tax returns	2011-2019	Exelon, Generation
Pennsylvania separate corporate income tax returns	2017-2019	PECO

(a) Certain registrants are only open to assessment for tax years since joining the Exelon federal consolidated group; BGE beginning in 2012 and PHI, Pepco, DPL, and ACE beginning in 2016.

Other Tax Matters

Long-Term Marginal State Income Tax Rate (All Registrants)

Quarterly, Exelon reviews and updates its marginal state income tax rates for changes in state apportionment. The Registrants remeasure their existing deferred income tax balances to reflect the changes in marginal rates, which results in either an increase or a decrease to their net deferred income tax liability balances. Utility Registrants record 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. The impacts to the Utility Registrants for the years ended December 31, 2020, 2019, and 2018 were not material.

December 31, 2020	Exelon	Generation
Increase (decrease) to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	$ 66	$ (26)
December 31, 2019		
Increase to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	$ 23	$ 9
December 31, 2018		
Decrease to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	$ (50)	$ (53)

Allocation of Tax Benefits (All Registrants)

Generation and the Utility Registrants are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net federal and state benefits attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit.

The following table presents the allocation of tax benefits from Exelon under the Tax Sharing Agreement.

	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2020[a]	$ 64	$ 14	$ 17	$ —	$ 17	$ 8	$ 6	$ 1
December 31, 2019[b]	41	—	14	3	7	6	1	—
December 31, 2018[c]	155	1	48	26	2	—	—	—

(a) BGE 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.
(b) ACE 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.
(c) Pepco, DPL, and ACE 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.

Research and Development Activities

In the fourth quarter of 2019, Exelon and Generation recognized additional tax benefits related to certain research and development activities that qualify for federal and state tax incentives for the 2010 through 2018 tax years, which resulted in an increase to Exelon’s and Generation’s net income of $108 million and $75 million, respectively, for the year ended December 31, 2019, reflecting a decrease to Exelon’s and Generation’s Income tax expense of $97 million and $66 million, respectively.

15. Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and OPEB plans for essentially all current employees. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018 for most newly-hired Generation and BSC non-represented, non-craft, employees and January 1, 2021 for most newly-hired utility management employees, these newly-hired employees are not eligible for pension benefits, and will instead be eligible to receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented, non-craft, employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits. Effective January 1, 2021, most non-represented, non-craft, employees who are under the age of 40 are not eligible for retiree health care benefits.

Effective January 1, 2019, Exelon merged the Exelon Corporation Cash Balance Pension Plan (CBPP) into the Exelon Corporation Retirement Program (ECRP). The merging of the plans did not change the benefits offered to the plan participants and, thus, had no impact on Exelon's pension obligation. However, beginning in 2019, actuarial losses and gains related to the CBPP and ECRP are amortized over participants’ average remaining service period of the merged ECRP rather than each individual plan.

The table below shows the pension and OPEB plans in which employees of each operating company participated at December 31, 2020:

	Operating Company[e]							
Name of Plan:	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Qualified Pension Plans:								
Exelon Corporation Retirement Program[a]	X	X	X	X	X	X	X	X
Exelon Corporation Pension Plan for Bargaining Unit Employees[a]	X	X						
Exelon New England Union Employees Pension Plan[a]	X							
Exelon Employee Pension Plan for Clinton, TMI, and Oyster Creek[a]	X	X	X	X	X			X
Pension Plan of Constellation Energy Group, Inc.[b]	X	X	X	X	X	X	X	
Pension Plan of Constellation Energy Nuclear Group, LLC[c]	X	X		X	X	X		
Nine Mile Point Pension Plan[c]	X							
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B[b]	X							
Pepco Holdings LLC Retirement Plan[d]	X	X	X	X	X	X	X	X
Non-Qualified Pension Plans:								
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan[a]	X	X	X		X			
Exelon Corporation Supplemental Management Retirement Plan[a]	X	X	X	X	X	X		X
Constellation Energy Group, Inc. Senior Executive Supplemental Plan[b]	X			X	X			
Constellation Energy Group, Inc. Supplemental Pension Plan[b]	X			X	X			
Constellation Energy Group, Inc. Benefits Restoration Plan[b]	X	X		X	X			
Constellation Energy Nuclear Plan, LLC Executive Retirement Plan[c]	X				X			
Constellation Energy Nuclear Plan, LLC Benefits Restoration Plan[c]	X				X			
Baltimore Gas & Electric Company Executive Benefit Plan[b]	X			X				
Baltimore Gas & Electric Company Manager Benefit Plan[b]	X	X		X				
Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan[d]	X				X	X	X	X
Conectiv Supplemental Executive Retirement Plan[d]	X				X		X	X
Pepco Holdings LLC Combined Executive Retirement Plan[d]					X	X		
Atlantic City Electric Director Retirement Plan[d]								X

	Operating Company[e]							
Name of Plan:	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
OPEB Plans:								
PECO Energy Company Retiree Medical Plan[a]	X	X	X	X	X	X	X	X
Exelon Corporation Health Care Program[a]	X	X	X	X	X	X		X
Exelon Corporation Employees' Life Insurance Plan[a]	X	X	X	X				
Exelon Corporation Health Reimbursement Arrangement Plan[a]	X	X	X	X				
Constellation Energy Group, Inc. Retiree Medical Plan[b]	X	X	X	X	X	X		
Constellation Energy Group, Inc. Retiree Dental Plan[b]	X			X				
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan[b]	X	X	X	X	X	X		
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan[b]	X			X				
Exelon New England Union Post-Employment Medical Savings Account Plan[a]	X							
Retiree Medical Plan of Constellation Energy Nuclear Group, LLC[c]	X	X		X		X		
Retiree Dental Plan of Constellation Energy Nuclear Group, LLC[c]	X	X		X		X		
Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees[c]	X							
Pepco Holdings LLC Welfare Plan for Retirees[d]	X	X	X	X	X	X	X	X

(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 CENG plans.
(d) These plans are collectively referred to as the legacy PHI plans.
(e) Employees generally remain in their legacy benefit plans when transferring between operating companies.

Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Exelon has elected that the trusts underlying these plans be treated as qualified trusts under the IRC. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets, and Funded Status

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 loss increased by $7 million (after-tax) and regulatory assets and liabilities increased by $19 million and decreased by $10 million, respectively.

The following tables provide a rollforward of the changes in the benefit obligations and plan assets of Exelon for the most recent two years for all plans combined:

	Pension Benefits		OPEB	
	2020	2019	2020	2019
Change in benefit obligation:				
Net benefit obligation at beginning of year	$ 22,868	$ 20,692	$ 4,658	$ 4,369
Service cost	387	357	90	93
Interest cost	757	883	154	188
Plan participants' contributions	—	—	49	44
Actuarial loss[a]	2,217	2,322	49	250
Plan amendments	—	68	(111)	—
Curtailments	—	(3)	—	—
Settlements	(45)	(35)	(5)	(4)
Contractual termination benefits	—	1	—	—
Gross benefits paid	(1,290)	(1,417)	(280)	(282)
Net benefit obligation at end of year	$ 24,894	$ 22,868	$ 4,604	$ 4,658

	Pension Benefits		OPEB	
	2020	2019	2020	2019
Change in plan assets:				
Fair value of net plan assets at beginning of year	$ 18,590	$ 16,678	$ 2,541	$ 2,408
Actual return on plan assets	2,547	3,008	190	324
Employer contributions	542	356	59	51
Plan participants' contributions	—	—	49	44
Gross benefits paid	(1,290)	(1,417)	(280)	(282)
Settlements	(45)	(35)	(5)	(4)
Fair value of net plan assets at end of year	$ 20,344	$ 18,590	$ 2,554	$ 2,541

(a) The pension and OPEB actuarial losses in 2020 and 2019 primarily reflect a decrease in the discount rate. OPEB losses in 2020 were offset by gains related to plan changes.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		OPEB	
	2020	2019	2020	2019
Other current liabilities	$ 47	$ 31	$ 42	$ 41
Pension obligations	4,503	4,247	—	—
Non-pension postretirement benefit obligations	—	—	2,008	2,076
Unfunded status (net benefit obligation less plan assets)	$ 4,550	$ 4,278	$ 2,050	$ 2,117

The following table provides the ABO and fair value of plan assets for all pension plans with an ABO in excess of plan assets. Information for pension and OPEB plans with projected benefit obligations (PBO) and accumulated postretirement benefit obligation (APBO), respectively, in excess of plan assets has been disclosed in the Obligations and Plan Assets table above as all pension and OPEB plans are underfunded.

ABO in excess of plan assets	Exelon	
	2020	2019
ABO	$ 23,514	$ 21,727
Fair value of net plan assets	20,344	18,590

Components of Net Periodic Benefit Costs

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

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 years ended December 31, 2020, 2019, and 2018.

	Pension Benefits			OPEB		
	2020	2019	2018	2020	2019	2018
Components of net periodic benefit cost:						
Service cost	$ 387	$ 357	$ 405	$ 90	$ 93	$ 112
Interest cost	757	883	802	154	188	175
Expected return on assets	(1,270)	(1,225)	(1,252)	(163)	(153)	(173)
Amortization of:						
Prior service cost (credit)	4	—	2	(124)	(179)	(186)
Actuarial loss	512	414	629	49	45	66
Curtailment benefits	—	—	—	(1)	—	—
Settlement and other charges	14	17	3	1	1	1
Contractual termination benefits	—	1	—	—	—	—
Net periodic benefit cost	$ 404	$ 447	$ 589	$ 6	$ (5)	$ (5)

Cost Allocation to Exelon Subsidiaries

All Registrants account for their participation in Exelon’s pension and OPEB plans by applying multi-employer accounting. Exelon allocates costs related to its pension and OPEB plans to its subsidiaries based on both active and retired employee participation in each plan.

The amounts below represent the Registrants' allocated pension and OPEB costs. For Exelon, the service cost component is included in Operating and maintenance expense and Property, plant, and equipment, net while the non-service cost components are included in Other, net and Regulatory assets. For Generation and the Utility Registrants, the service cost and non-service cost components are included in Operating and maintenance expense and Property, plant, and equipment, net in their consolidated financial statements.

For the Years Ended December 31,	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2020	$ 411	$ 115	$ 114	$ 5	$ 64	$ 70	$ 15	$ 7	$ 14
2019	442	135	96	12	61	95	25	15	16
2018	583	204	177	18	60	67	15	6	12

Components of AOCI and Regulatory Assets

Exelon recognizes the overfunded or underfunded status of defined benefit pension and OPEB plans as an asset or liability on its balance sheet, with offsetting entries to AOCI and regulatory assets (liabilities). A portion of current year actuarial (gains) losses and prior service costs (credits) is capitalized within Exelon’s Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets (liabilities) for Exelon for the years ended December 31, 2020, 2019, and 2018 for all plans combined.

	Pension Benefits			OPEB		
	2020	2019	2018	2020	2019	2018
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial loss (gain)	$ 941	$ 538	$ 635	$ 22	$ 80	$ (232)
Amortization of actuarial loss	(512)	(414)	(629)	(49)	(45)	(66)
Current year prior service cost (credit)	—	68	(4)	(111)	—	—
Amortization of prior service (cost) credit	(4)	—	(2)	124	179	186
Curtailments	—	(3)	—	1	—	—
Settlements	(14)	(17)	(3)	(1)	(1)	—
Total recognized in AOCI and regulatory assets (liabilities)	$ 411	$ 172	$ (3)	$ (14)	$ 213	$ (112)
Total recognized in AOCI	$ 271	$ 169	$ 3	$ 6	$ 107	$ (55)
Total recognized in regulatory assets (liabilities)	$ 140	$ 3	$ (6)	$ (20)	$ 106	$ (57)

The following table provides the components of gross accumulated other comprehensive loss and regulatory assets (liabilities) for Exelon that have not been recognized as components of periodic benefit cost at December 31, 2020 and 2019, respectively, for all plans combined:

	Pension Benefits		OPEB	
	2020	2019	2020	2019
Prior service cost (credit)	$ 35	$ 39	$ (145)	$ (158)
Actuarial loss	8,077	7,662	538	565
Total	$ 8,112	$ 7,701	$ 393	$ 407
Total included in AOCI	$ 4,339	$ 4,068	$ 183	$ 177
Total included in regulatory assets (liabilities)	$ 3,773	$ 3,633	$ 210	$ 230

Average Remaining Service Period

For pension benefits, Exelon amortizes its unrecognized prior service costs (credits) and certain actuarial (gains) losses, as applicable, based on participants' average remaining service periods.

For OPEB, Exelon amortizes its unrecognized prior service costs (credits) over participants' average remaining service period to benefit eligibility age and amortizes certain actuarial (gains) losses over participants' average remaining service period to expected retirement. The resulting average remaining service periods for pension and OPEB were as follows:

	2020	2019	2018
Pension plans	12.3	11.7	12.0
OPEB plans:			
Benefit Eligibility Age	9.0	8.7	8.8
Expected Retirement	10.2	9.3	9.5

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and OPEB plans involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. The measurement of benefit obligations and costs is impacted by several assumptions and inputs, as shown below, among other factors. When developing the required assumptions, Exelon considers historical information as well as future expectations.

Expected Rate of Return. In determining the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

Mortality. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. For the year ended December 31, 2020, Exelon's mortality assumption utilizes the SOA 2019 base table (Pri-2012) and MP-2020 improvement scale adjusted to use Proxy SSA ultimate improvement rates. For the year ended December 31, 2019, Exelon's mortality assumption utilizes the SOA 2019 base table (Pri-2012) and MP-2019 improvement scale adjusted to a 0.75% long-term rate reached in 2035.

For Exelon, the following assumptions were used to determine the benefit obligations for the plans at December 31, 2020 and 2019. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits		OPEB	
	2020	2019	2020	2019
Discount rate	2.58 %[a]	3.34 %[a]	2.51 %[a]	3.31 %[a]
Investment crediting rate	3.72 %[b]	3.82 %[b]	N/A	N/A
Rate of compensation increase	3.75 %	[c]	3.75 %	[c]
Mortality table	Pri-2012 table with MP- 2020 improvement scale (adjusted)	Pri-2012 table with MP- 2019 improvement scale (adjusted)	Pri-2012 table with MP- 2020 improvement scale (adjusted)	Pri-2012 table with MP- 2019 improvement scale (adjusted)
Health care cost trend on covered charges	N/A	N/A	Initial and ultimate rate of 5.00%	5.00% with ultimate trend of 5.00% in 2017

(a) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and OPEB obligations. Certain benefit plans used individual rates, which range from 2.11% - 2.73% and 2.45% - 2.63% for pension and OPEB plans, respectively, as of December 31, 2020 and 3.02% - 3.44% and 3.27% - 3.40% for pension and OPEB plans, respectively, as of December 31, 2019.
(b) The investment crediting rate above represents a weighted average rate.
(c) 3.25% through 2019 and 3.75% thereafter.

The following assumptions were used to determine the net periodic benefit cost for Exelon for the years ended December 31, 2020, 2019 and 2018:

	Pension Benefits			OPEB		
	2020	2019	2018	2020	2019	2018
Discount rate	3.34 %[a]	4.31 %[a]	3.62 %[a]	3.31 %[a]	4.30 %[a]	3.61 %[a]
Investment crediting rate	3.82 %[b]	4.46 %[b]	4.00 %[b]	N/A	N/A	N/A
Expected return on plan assets	7.00 %[c]	7.00 %[c]	7.00 %[c]	6.69 %[c]	6.67 %[c]	6.60 %[c]
Rate of compensation increase	[d]	[d]	[d]	[d]	[d]	[d]
Mortality table	Pri-2012 table with MP-2019 improvement scale (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	Pri-2012 table with MP-2019 improvement scale (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)
Health care cost trend on covered charges	N/A	N/A	N/A	Initial and ultimate rate of 5.00%	5.00% with ultimate trend of 5.00% in 2017	5.00% with ultimate trend of 5.00% in 2017

(a) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and OPEB costs. Certain benefit plans used individual rates, which range from 3.02%-3.44% and 3.27%-3.40% for pension and OPEB plans, respectively, for the year ended December 31, 2020; 4.13%-4.36% and 4.27%-4.38% for pension and OPEB plans; respectively, for the year ended December 31, 2019; and 3.49%-3.65% and 3.57%-3.68% for pension and OPEB plans, respectively, for the year ended December 31, 2018.

(b) The investment crediting rate above represents a weighted average rate.

(c) Not applicable to pension and OPEB plans that do not have plan assets.

(d) 3.25% through 2019 and 3.75% thereafter.

Contributions

Exelon allocates contributions related to its legacy Exelon pension and OPEB plans to its subsidiaries based on accounting cost. For legacy CEG, CENG, FitzPatrick, and PHI plans, pension and OPEB contributions are allocated to the subsidiaries based on employee participation (both active and retired). The following tables provide contributions to the pension and OPEB plans:

	Pension Benefits			OPEB		
	2020	2019	2018	2020	2019	2018
Exelon	$ 542	$ 356	$ 337	$ 59	$ 51	$ 46
Generation	236	160	128	19	15	11
ComEd	143	72	38	5	5	4
PECO	18	27	28	—	1	—
BGE	56	34	40	22	14	14
PHI	30	10	62	9	15	12
Pepco	2	2	6	9	12	11
DPL	—	1	—	—	—	—
ACE	2	—	6	—	1	—

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation, and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy to make levelized annual contributions with the objective of achieving 100% funded status on an ABO basis over time. This level funding strategy helps minimize volatility of future period required pension contributions. Based on this funding strategy and current market conditions, which are subject to change, Exelon's estimated annual qualified pension contributions will be approximately $500 million in 2021. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

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

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

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Exelon	$ 505	$ 51	$ 75
Generation	196	27	24
ComEd	170	2	23
PECO	14	1	—
BGE	57	1	16
PHI	29	9	7
Pepco	1	2	6
DPL	—	1	—
ACE	3	—	—

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2020 were:

	Pension Benefits	OPEB
2021	$ 1,279	$ 257
2022	1,280	259
2023	1,315	261
2024	1,325	262
2025	1,338	265
2026 through 2030	6,759	1,320
Total estimated future benefit payments through 2030	$ 13,296	$ 2,624

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's OPEB plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and OPEB plans. The actual asset returns across Exelon's pension and OPEB plans for the year ended December 31, 2020 were 14.45% and 9.14%, respectively, compared to an expected long-term return assumption of 7.00% and 6.69%, respectively. Exelon used an EROA of 7.00% and 6.46% to estimate its 2021 pension and OPEB costs, respectively.

Exelon's pension and OPEB plan target asset allocations at December 31, 2020 and 2019 were as follows:

	December 31, 2020		December 31, 2019	
Asset Category	Pension Benefits	OPEB	Pension Benefits	OPEB
Equity securities	34 %	45 %	33 %	46 %
Fixed income securities	43 %	39 %	44 %	32 %
Alternative investments[(a)]	23 %	16 %	23 %	22 %
Total	100 %	100 %	100 %	100 %

(a) Alternative investments include private equity, hedge funds, real estate, and private credit.

Concentrations of Credit Risk. Exelon evaluated its pension and OPEB plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2020. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2020, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in Exelon's pension and OPEB plan assets.

Fair Value Measurements

The following tables present pension and OPEB plan assets measured and recorded at fair value in Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2020 and 2019:

	December 31, 2020					December 31, 2019				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets(a)										
Cash equivalents	$ 408	$ 121	$ —	$ —	$ 529	$ 258	$ 107	$ —	$ —	$ 365
Equities(b)	4,255	—	2	2,552	6,809	3,616	1	5	2,589	6,211
Fixed income:										
U.S. Treasury and agencies	1,137	367	—	—	1,504	1,294	280	—	—	1,574
State and municipal debt	—	85	—	—	85	—	56	—	—	56
Corporate debt(c)	—	4,873	573	—	5,446	—	4,390	245	—	4,635
Other(b)	—	239	21	537	797	—	305	—	851	1,156
Fixed income subtotal	1,137	5,564	594	537	7,832	1,294	5,031	245	851	7,421
Private equity	—	—	—	1,632	1,632	—	—	—	1,391	1,391
Hedge funds	—	—	—	1,314	1,314	—	—	—	1,126	1,126
Real estate	—	—	—	1,080	1,080	—	—	—	1,030	1,030
Private credit	—	—	234	1,046	1,280	—	—	237	929	1,166
Pension plan assets subtotal	5,800	5,685	830	8,161	20,476	5,168	5,139	487	7,916	18,710
OPEB plan assets(a)										
Cash equivalents	50	52	—	—	102	39	49	—	—	88
Equities	618	2	—	569	1,189	473	5	—	719	1,197
Fixed income:										
U.S. Treasury and agencies	16	66	—	—	82	17	64	—	—	81
State and municipal debt	—	89	—	—	89	—	107	—	—	107
Corporate debt(c)	—	89	—	—	89	—	71	—	—	71
Other	285	3	—	179	467	258	5	—	201	464
Fixed income subtotal	301	247	—	179	727	275	247	—	201	723
Hedge funds	—	—	—	308	308	—	—	—	293	293
Real estate	—	—	—	111	111	—	—	—	109	109
Private credit	—	—	—	117	117	—	—	—	131	131
OPEB plan assets subtotal	969	301	—	1,284	2,554	787	301	—	1,453	2,541
Total pension and OPEB plan assets(d)	$ 6,769	$ 5,986	$ 830	$ 9,445	$ 23,030	$ 5,955	$ 5,440	$ 487	$ 9,369	$ 21,251

(a) See Note 18—Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.

(b) Includes derivative instruments of $2 million for the years ended December 31, 2020 and 2019, which have total notional amounts of $6,879 million and $6,668 million at December 31, 2020 and 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 the company's exposure to credit or market loss.

(c) Includes investments in equities sold short held in investment vehicles primarily to hedge the equity option component of its convertible debt. Pension equities sold short totaled $(96) million and $(75) million as of December 31, 2020 and 2019, respectively. OPEB equities sold short totaled $(42) million and $(35) million as of December 31, 2020 and 2019, respectively.

(d) Excludes net liabilities of $132 million and $120 million at December 31, 2020 and 2019, respectively, which include certain derivative assets that have notional amounts of $239 million and $632 million at December 31, 2020 and 2019, respectively. These items are required to reconcile to the fair value of net plan assets and consist primarily of receivables or payables related to pending securities sales and purchases and interest and dividends receivable.

The following table presents the reconciliation of Level 3 assets and liabilities for Exelon measured at fair value for pension and OPEB plans for the years ended December 31, 2020 and 2019:

	Fixed Income	Equities	Private Credit	Total
Pension Assets				
Balance as of January 1, 2020	$ 245	$ 5	$ 237	$ 487
Actual return on plan assets:				
Relating to assets still held at the reporting date	19	(3)	15	31
Purchases, sales and settlements:				
Purchases	34	—	24	58
Settlements[a]	(3)	—	(42)	(45)
Transfers into Level 3[b]	299	—	—	299
Balance as of December 31, 2020	$ 594	$ 2	$ 234	$ 830

	Fixed Income	Equities	Private Credit	Total
Pension Assets				
Balance as of January 1, 2019	$ 216	$ 2	$ 268	$ 486
Actual return on plan assets:				
Relating to assets still held at the reporting date	28	3	28	59
Relating to assets sold during the period	(7)	—	—	(7)
Purchases, sales and settlements:				
Purchases	26	—	41	67
Sales	(4)	—	—	(4)
Settlements[a]	(2)	—	(100)	(102)
Transfers out of Level 3	(12)	—	—	(12)
Balance as of December 31, 2019	$ 245	$ 5	$ 237	$ 487

(a) Represents cash settlements only.

(b) In 2020, a contract was terminated for a certain fixed income commingled fund resulting in the ownership of certain fixed income securities which led to a transfer into Level 3 from not subject to leveling of $299 million.

Valuation Techniques Used to Determine Fair Value

The techniques used to fair value the pension and OPEB assets invested in cash equivalents, equities, fixed income, derivatives, private equity, real estate, and private credit investments are the same as the valuation techniques for these types of investments in NDTFs. See Cash Equivalents and NDT Fund Investments in Note 18 - Fair Value of Financial Assets and Liabilities for further information.

Pension and OPEB assets also include investments in hedge funds. Hedge fund investments include those that employ a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or its equivalent as a practical expedient, and therefore, hedge funds are not classified within the fair value hierarchy. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate.

Defined Contribution Savings Plan (All Registrants)

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 matching contributions to the savings plan for the years ended December 31, 2020, 2019, and 2018:

For the Years Ended December 31,	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2020	$ 158	$ 63	$ 36	$ 12	$ 13	14	$ 4	$ 3	$ 3
2019	161	73	35	11	12	13	3	3	2
2018	179	86	37	9	12	13	3	2	2

16. 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 referenced contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. In the tables below, which present fair value balances, Generation's energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting columns.

Generation's and ComEd's use of cash collateral is generally unrestricted unless Generation or ComEd are downgraded below investment grade. Cash collateral held by PECO, BGE, Pepco, DPL, and ACE must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

Commodity Price Risk (All Registrants)

Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options, and short-term and long-term commitments to purchase and sell energy and commodity products. The Registrants believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

Generation. To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels, and other commodities. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. To manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation’s energy marketing portfolio but represent a small portion of Generation’s overall energy marketing activities and are subject to limits established by Exelon’s RMC.

Utility Registrants. The Utility Registrants procure electric and natural gas supply through a competitive procurement process approved by each of the respective state utility commissions. The Utility Registrants’ 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 10% of planned natural gas purchases in support of projected firm sales.
BGE	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed price contracts for between 10-20% of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period.
Pepco	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
DPL	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed and Index priced contracts through full requirements contracts.
		Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability[(c)]	Exchange traded future contracts for up to 50% of estimated monthly purchase requirements each month, including purchases for storage injections.
ACE	Electricity	NPNS	Fixed price contracts for all BGS requirements through full requirements contracts.

(a) See Note 3—Regulatory Matters 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 December 31, 2020 and 2019 and is not presented in the fair value tables below.

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

	Exelon	Generation					ComEd
December 31, 2020	**Total Derivatives**	**Economic Hedges**	**Proprietary Trading**	**Collateral[a][b]**	**Netting[a]**	**Subtotal**	**Economic Hedges**
Mark-to-market derivative assets (current assets)	$ 639	$ 2,757	$ 40	$ 103	$ (2,261)	$ 639	$ —
Mark-to-market derivative assets (noncurrent assets)	554	1,501	4	64	(1,015)	554	—
Total mark-to-market derivative assets	1,193	4,258	44	167	(3,276)	1,193	—
Mark-to-market derivative liabilities (current liabilities)	(293)	(2,629)	(23)	131	2,261	(260)	(33)
Mark-to-market derivative liabilities (noncurrent liabilities)	(472)	(1,335)	(2)	118	1,015	(204)	(268)
Total mark-to-market derivative liabilities	(765)	(3,964)	(25)	249	3,276	(464)	(301)
Total mark-to-market derivative net assets (liabilities)	$ 428	$ 294	$ 19	$ 416	$ —	$ 729	$ (301)
December 31, 2019							
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 not material and not reflected in the table above.

(b) Of the collateral posted, $209 million and $511 million represents variation margin on the exchanges at December 31, 2020 and 2019, respectively.

Economic Hedges (Commodity Price Risk)

Generation. For the years ended December 31, 2020, 2019, and 2018, 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.

	Gain (Loss)		
Income Statement Location	**2020**	**2019**	**2018**
Operating revenues	$ 112	$ —	$ (270)
Purchased power and fuel	168	(204)	(47)
Total Exelon and Generation	$ 280	$ (204)	$ (317)

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 December 31, 2020, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% for 2021.

Proprietary Trading (Commodity Price Risk)

Generation also executes commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows. For the years ended December 31, 2020, 2019, and 2018, net pre-tax commodity mark-to-market gains and losses for Exelon and Generation were not material. The Utility Registrants do not execute derivatives for proprietary trading purposes.

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 $516 million and $1,269 million at December 31, 2020 and 2019, respectively, for Exelon and $516 million and $569 million at December 31, 2020 and 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 $149 million and $231 million at December 31, 2020 and 2019, respectively.

The mark-to-market derivative assets and liabilities as of December 31, 2020 and 2019 and the mark-to-market gains and losses for the years ended December 31, 2020, 2019, and 2018 were not material for Exelon and Generation.

Credit Risk (All Registrants)

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

Generation. For commodity derivatives, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

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 December 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 December 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	$ 577	$ 27	$ 550	—	$ —
Non-investment grade	32	—	32		
No external ratings					
Internally rated — investment grade	165	1	164		
Internally rated — non-investment grade	80	28	52		
Total	$ 854	$ 56	$ 798	—	$ —

Net Credit Exposure by Type of Counterparty	As of December 31, 2020
Financial institutions	$ 15
Investor-owned utilities, marketers, power producers	607
Energy cooperatives and municipalities	138
Other	38
Total	$ 798

(a) As of December 31, 2020, credit collateral held from counterparties where Generation had credit exposure included $31 million of cash and $25 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 December 31, 2020, the Utility Registrants' counterparty credit risk with suppliers was not material.

Credit-Risk-Related Contingent Features (All Registrants)

Generation. As part of the normal course of business, Generation routinely enters into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances, and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

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:

	As of December 31,	
Credit-Risk Related Contingent Features	**2020**	**2019**
Gross fair value of derivative contracts containing this feature[(a)]	$ (834)	$ (956)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	537	649
Net fair value of derivative contracts containing this feature[(c)]	$ (297)	$ (307)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features ignoring the effects of master netting agreements.

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which Generation could potentially be required to post collateral.

(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

As of December 31, 2020 and 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.

	As of December 31,	
	2020	**2019**
Cash collateral posted	$ 511	$ 982
Letters of credit posted	226	264
Cash collateral held	110	103
Letters of credit held	40	112
Additional collateral required in the event of a credit downgrade below investment grade	1,432	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's, and DPL's credit rating. As of December 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 credit rating as of December 31, 2020, they could have been required to post incremental collateral to their counterparties of $34 million, $54 million, and $9 million, respectively.

17. 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 borrowings from the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at December 31, 2020 and 2019:

	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings at December 31,	
Commercial Paper Issuer	**2020[a][b][c]**	**2019[a][b][c]**	**2020**	**2019**	**2020**	**2019**
Exelon[d]	$ 9,000	$ 9,000	$ 1,031	$ 870	0.25 %	2.25 %
Generation	5,300	5,300	340	320	0.27 %	1.84 %
ComEd	1,000	1,000	323	130	0.23 %	2.38 %
PECO	600	600	—	—	— %	2.39 %
BGE	600	600	—	76	— %	2.46 %
PHI[e]	900	900	368	208	0.24 %	N/A
Pepco	300	300	35	82	0.22 %	2.56 %
DPL	300	300	146	56	0.24 %	2.02 %
ACE	300	300	187	70	0.25 %	2.43 %

(a) Excludes $1,500 million and $1,400 million in bilateral credit facilities at December 31, 2020 and 2019, respectively, and $144 million and $159 million in credit facilities for project finance at December 31, 2020 and 2019, respectively. These credit facilities do not back Generation's commercial paper program.

(b) At December 31, 2020, excludes $135 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL, and ACE with aggregate commitments of $38 million, $32 million, $33 million, $8 million, $8 million, $8 million, and $8 million, respectively. These facilities expire on October 8, 2021. These facilities are solely utilized to issue letters of credit. At December 31, 2019, excludes $142 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL, and ACE with aggregate commitments of $44 million, $33 million, $33 million, $8 million, $8 million, $8 million, and $8 million, respectively.

(c) Pepco, DPL, and ACE's revolving credit facility has the ability to flex to $500 million, $500 million, and $350 million, respectively. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL, or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.

(d) Includes revolving credit agreement at Exelon Corporate with a maximum program size of $600 million at both December 31, 2020 and 2019, respectively. Exelon Corporate had no outstanding commercial paper as of December 31, 2020 and $136 million at 2019 with an average interest rate on commercial paper borrowings of 1.92%.

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

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

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

					Available Capacity at December 31, 2020	
Borrower[(a)]	**Facility Type**	**Aggregate Bank Commitment**[(b)]	**Facility Draws**	**Outstanding Letters of Credit**	**Actual**	**To Support Additional Commercial Paper**[(c)]
Exelon[(c)]	Syndicated Revolver / Bilaterals / Project Finance	$ 10,644	$ —	$ 1,230	$ 9,414	$ 7,698
Generation	Syndicated Revolver	5,300	—	262	5,038	4,698
Generation	Bilaterals	1,500	—	840	660	—
Generation	Project Finance	144	—	119	25	—
ComEd	Syndicated Revolver	1,000	—	2	998	675
PECO	Syndicated Revolver	600	—	—	600	600
BGE	Syndicated Revolver	600	—	—	600	600
PHI	Syndicated Revolver	900	—	1	899	531
Pepco	Syndicated Revolver	300	—	1	299	264
DPL	Syndicated Revolver	300	—	—	300	154
ACE	Syndicated Revolver	300	—	—	300	113

(a) On May 26, 2018, each of the Registrants' respective syndicated revolving credit facilities had their maturity dates extended to May 26, 2023.

(b) Excludes $135 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL, and ACE with aggregate commitments of $38 million, $32 million, $33 million, $8 million, $8 million, $8 million, and $8 million, respectively. These facilities expire on October 8, 2021. These facilities are solely utilized to issue letters of credit. As of December 31, 2020, letters of credit issued under these facilities totaled $5 million, $5 million, and $2 million for Generation, ComEd, and BGE, respectively.

(c) Includes $600 million aggregate bank commitment related to Exelon Corporate. Exelon Corporate had $6 million outstanding letters of credit at December 31, 2020. Exelon Corporate had $594 million in available capacity to support additional commercial paper at December 31, 2020.

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. The funds were used to refinance commercial paper. Generation repaid the $1.5 billion borrowed on the revolving credit facility on April 3, 2020.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a 12-month term loan agreement for $500 million, which was renewed annually on March 22, 2018, March 20, 2019, and March 19, 2020, respectively. The loan agreement will expire on March 18, 2021. Pursuant to the loan agreement, as of December 31, 2020, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. The loans beared interest at LIBOR plus 0.95% as of December 31, 2019 as part of the March 20, 2019 renewal. The loan agreement is reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On March 19, 2020, Generation entered into a term loan agreement for $200 million. The loan agreement 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.

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.

On January 25, 2021, ComEd entered into two 90-day term loan agreements of $125 million each with variable interest rates of LIBOR plus 0.50% and LIBOR plus 0.75%, respectively.

Revolving 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 as needed.

Bilateral Credit Agreements

The following table reflects the bilateral credit agreements at December 31, 2020:

Registrant	Date Initiated	Latest Amendment Date	Maturity Date[a]	Amount
Generation[b]	October 26, 2012	October 23, 2020	October 22, 2021	$ 200
Generation[c]	January 11, 2013	January 4, 2019	March 1, 2021	100
Generation[c]	January 5, 2016	January 4, 2019	April 5, 2021	150
Generation[c]	February 21, 2019	N/A	March 31, 2021	100
Generation[c]	October 25, 2019	N/A	N/A	200
Generation[c]	October 25, 2019	N/A	N/A	100
Generation[c]	November 20, 2019	N/A	N/A	300
Generation[c]	November 21, 2019	N/A	N/A	150
Generation[c]	November 21, 2019	N/A	November 21, 2021	100
Generation[c]	May 15, 2020	N/A	N/A	100

(a) Credit facilities that do not contain a maturity date are specific to the agreements set within each contract. In some instances, credit facilities are automatically renewed based on the contingency standards set within the specific agreement.
(b) Bilateral credit facility relates to CENG, which is incorporated within Generation, and supports the issuance of letters of credit and funding for working capital and does not back Generation's commercial paper program. During the second and third quarters of 2020, CENG drew on its bilateral credit facility. As of December 31, 2020, there was no outstanding balance at this facility.
(c) Bilateral credit agreements solely support the issuance of letters of credit and do not back Generation's commercial paper program.

Borrowings under Exelon’s, Generation’s, ComEd’s, PECO’s, BGE's, Pepco's, DPL's, and ACE'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 the particular Registrant’s credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon[a]	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	0 - 27.5	27.5	—	—	—	7.5	—	7.5
LIBOR-based borrowings	90.0 - 127.5	127.5	100.0	90.0	90.0	107.5	100.0	107.5

(a) Includes interest rate adders at Exelon Corporate of 27.5 and 127.5 for prime and LIBOR-based borrowings, respectively.

If any registrant loses its investment grade rating, the maximum adders for prime rate borrowings and LIBOR-based rate borrowings would be 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

Variable Rate Demand Bonds

DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders 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, PHI views VRDBs as a source of long-term financing. As of both December 31, 2020 and December 31, 2019, $79 million in variable rate demand bonds issued by DPL were outstanding and are included in the Long-term debt due within one year in Exelon's, PHI's, and DPL's Consolidated Balance Sheet.

Long-Term Debt

The following tables present the outstanding long-term debt at the Registrants as of December 31, 2020 and 2019:

Exelon

	Rates			Maturity Date	December 31,	
					2020	2019
Long-term debt						
First mortgage bonds[(a)]	0.19 %	-	7.90 %	2021 - 2050	$ 18,915	$ 17,486
Senior unsecured notes	2.45 %	-	7.60 %	2021 - 2050	10,585	10,685
Unsecured notes	2.40 %	-	6.35 %	2021 - 2050	3,700	3,300
Pollution control notes	2.50 %	-	2.70 %	2020	—	412
Nuclear fuel procurement contracts			3.15 %	2020	—	3
Notes payable and other	2.10 %	-	7.99 %	2021 - 2053	170	154
Junior subordinated notes			3.50 %	2022	1,150	1,150
Long-term software licensing agreement			3.95 %	2024	30	55
Unsecured tax-exempt bonds	0.17 %	-	1.70 %	2022 - 2024	143	222
Medium-terms notes (unsecured)			7.72 %	2027	10	10
Transition bonds			5.55 %	2021	21	40
Loan agreement			2.00 %	2023	50	50
Nonrecourse debt:						
Fixed rates	2.29 %	-	6.00 %	2031 - 2037	977	1,182
Variable rates	2.99 %	-	3.18 %	2021 - 2027	765	811
Total long-term debt					36,516	35,560
Unamortized debt discount and premium, net					(77)	(72)
Unamortized debt issuance costs					(248)	(214)
Fair value adjustment					721	765
Long-term debt due within one year					(1,819)	(4,710)
Long-term debt					$ 35,093	$ 31,329
Long-term debt to financing trusts[(b)]						
Subordinated debentures to ComEd Financing III			6.35 %	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	5.25 %	-	7.38 %	2028	81	81
Subordinated debentures to PECO Trust IV			5.75 %	2033	103	103
Total long-term debt to financing trusts					$ 390	$ 390

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's, Pepco's, DPL's, and ACE's assets are subject to the liens of their respective mortgage indentures.
(b) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon's Consolidated Balance Sheets.

Generation

	Rates		Maturity Date	December 31, 2020	December 31, 2019
Long-term debt					
Senior unsecured notes	3.25 % -	7.60 %	2022 - 2042	$ 4,219	$ 5,420
Pollution control notes	2.50 % -	2.70 %	2020	—	412
Nuclear fuel procurement contracts		3.15 %	2020	—	3
Notes payable and other	2.10 % -	4.85 %	2021 - 2028	111	115
Nonrecourse debt:					
Fixed rates	2.29 % -	6.00 %	2031 - 2037	977	1,182
Variable rates	2.99 % -	3.18 %	2021 - 2027	765	811
Total long-term debt				6,072	7,943
Unamortized debt discount and premium, net				(5)	(5)
Unamortized debt issuance costs				(46)	(42)
Fair value adjustment				66	78
Long-term debt due within one year				(197)	(3,182)
Long-term debt				$ 5,890	$ 4,792

ComEd

	Rates		Maturity Date	December 31, 2020	December 31, 2019
Long-term debt					
First mortgage bonds[a]	2.20 % -	6.45 %	2021 - 2050	$ 9,079	$ 8,578
Other		7.49 %	2053	8	8
Total long-term debt				9,087	8,586
Unamortized debt discount and premium, net				(28)	(27)
Unamortized debt issuance costs				(76)	(68)
Long-term debt due within one year				(350)	(500)
Long-term debt				$ 8,633	$ 7,991
Long-term debt to financing trust[b]					
Subordinated debentures to ComEd Financing III		6.35 %	2033	$ 206	$ 206
Total long-term debt to financing trusts				206	206
Unamortized debt issuance costs				(1)	(1)
Long-term debt to financing trusts				$ 205	$ 205

(a) Substantially all of ComEd's assets, other than expressly excepted property, are subject to the lien of its mortgage indenture.
(b) Amount owed to this financing trust is recorded as Long-term debt to financing trust within ComEd's Consolidated Balance Sheets.

PECO

	Rates		Maturity Date	December 31,	
				2020	2019
Long-term debt					
First mortgage bonds[(a)]	1.70 % -	5.95 %	2021 - 2050	$ 3,750	$ 3,400
Loan agreement		2.00 %	2023	50	50
Total long-term debt				3,800	3,450
Unamortized debt discount and premium, net				(20)	(21)
Unamortized debt issuance costs				(27)	(24)
Long-term debt due within one year				(300)	—
Long-term debt				$ 3,453	$ 3,405
Long-term debt to financing trusts[(b)]					
Subordinated debentures to PECO Trust III	5.25 % -	7.38 %	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV		5.75 %	2033	103	103
Long-term debt to financing trusts				$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Amounts owed to this financing trust are recorded as Long-term debt to financing trusts within PECO's Consolidated Balance Sheets.

BGE

	Rates		Maturity Date	December 31,	
				2020	2019
Long-term debt					
Unsecured notes	2.40 % -	6.35 %	2021 - 2050	$ 3,700	$ 3,300
Total long-term debt				3,700	3,300
Unamortized debt discount and premium, net				(12)	(9)
Unamortized debt issuance costs				(24)	(21)
Long-term debt due within one year				(300)	—
Long-term debt				$ 3,364	$ 3,270

PHI

	Rates		Maturity Date	December 31,	
				2020	2019
Long-term debt					
First mortgage bonds[a]	0.19 % -	7.90 %	2021 - 2050	$ 6,086	$ 5,508
Senior unsecured notes		7.45 %	2032	185	185
Unsecured tax-exempt bonds	0.17 % -	1.70 %	2022 - 2024	143	222
Medium-terms notes (unsecured)		7.72 %	2027	10	10
Transition bonds		5.55 %	2021	21	40
Finance leases		3.54 %	2022 - 2028	50	28
Other	7.28 %-	7.99 %	2021 - 2022	1	2
Total long-term debt				6,496	5,995
Unamortized debt discount and premium, net				4	4
Unamortized debt issuance costs				(28)	(19)
Fair value adjustment				534	583
Long-term debt due within one year				(347)	(103)
Long-term debt				$ 6,659	$ 6,460

(a) Substantially all of Pepco's, DPL's, and ACE's assets are subject to the liens of their respective mortgage indentures.

Pepco

	Rates		Maturity Date	December 31,	
				2020	2019
Long-term debt					
First mortgage bonds[a]	2.53 % -	7.90 %	2022 - 2050	$ 3,075	$ 2,775
Unsecured tax-exempt bonds		1.70 %	2022	110	110
Finance leases		3.54 %	2025 - 2028	17	10
Other	7.28 % -	7.99 %	2021 - 2022	1	2
Total long-term debt				3,203	2,897
Unamortized debt discount and premium, net				2	2
Unamortized debt issuance costs				(40)	(35)
Long-term debt due within one year				(3)	(2)
Long-term debt				$ 3,162	$ 2,862

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

DPL

	Rates		Maturity Date	December 31, 2020	December 31, 2019
Long-term debt					
First mortgage bonds[a]	0.19 % -	4.27 %	2023 - 2049	$ 1,624	$ 1,446
Unsecured tax-exempt bonds	0.17 % -	0.20 %	2024	33	112
Medium-terms notes (unsecured)		7.72 %	2027	10	10
Finance leases		3.54 %	2025 - 2028	20	10
Total long-term debt				1,687	1,578
Unamortized debt discount and premium, net				1	1
Unamortized debt issuance costs				(11)	(12)
Long-term debt due within one year				(82)	(80)
Long-term debt				$ 1,595	$ 1,487

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

ACE

	Rates		Maturity Date	December 31, 2020	December 31, 2019
Long-term debt					
First mortgage bonds[a]	2.25 % -	6.80 %	2021 - 2050	$ 1,387	$ 1,287
Transition bonds		5.55 %	2021	21	40
Finance leases		3.54 %	2022 - 2028	13	8
Total long-term debt				1,421	1,335
Unamortized debt discount and premium, net				(1)	(1)
Unamortized debt issuance costs				(7)	(7)
Long-term debt due within one year				(261)	(20)
Long-term debt				$ 1,152	$ 1,307

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

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

Year	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2021	$ 1,819	$ 197	$ 350	$ 300	$ 300	$ 347	$ 3	$ 82	$ 261
2022	3,092	1,025	—	350	250	317	312	3	2
2023	859	1	—	50	300	508	3	503	2
2024	814	1	250	—	—	558	403	3	152
2025	2,215	900	—	350	—	158	3	3	152
Thereafter	28,107 (a)	3,948	8,692 (b)	2,934 (c)	2,850	4,608	2,479	1,093	852
Total	$ 36,906	$ 6,072	$ 9,292	$ 3,984	$ 3,700	$ 6,496	$ 3,203	$ 1,687	$ 1,421

(a) Includes $390 million due to ComEd and PECO financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.

Debt Covenants

As of December 31, 2020, the Registrants are in compliance with debt covenants.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing, in which approximately $2.2 billion of generating assets have been pledged as collateral at December 31, 2020. 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 nonrecourse debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, 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.

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. Interest rates on the loan were fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. The advances were completed as of December 31, 2015 and the outstanding loan balance will bear interest at an average blended interest rate of 2.82%. As of December 31, 2020 and December 31, 2019, approximately $460 million and $485 million were outstanding, respectively. In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2020, Generation had $37 million in letters of credit outstanding related to the project. In December 2017, Generation's interests in Antelope Valley were contributed to and are pledged as collateral for the EGR IV financing structures 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 provided 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 event of default and in 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. Further, distributions from Antelope Valley to EGR IV were suspended.

The United States Bankruptcy Court entered an order on June 20, 2020 confirming PG&E's plan of reorganization. On July 1, 2020 the plan became effective, and PG&E emerged from bankruptcy. On July 21, 2020, Antelope Valley received a waiver from the DOE for the event of default and, as such, distributions from Antelope Valley to EGR IV were permitted and the debt was classified as noncurrent as of June 30, 2020. The debt continues to be presented as noncurrent as of December 31, 2020.

See Note 12 — Asset Impairments for additional information.

Continental Wind, LLC. In September 2013, Continental Wind, an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million senior secured notes. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico, and Texas with a total net capacity of 667 MW. The net proceeds were distributed to Generation for its general business purposes. The notes are scheduled to mature on February 28, 2033. The notes bear interest at a fixed rate of 6.00% with interest payable semi-annually. As of December 31, 2020 and December 31, 2019, approximately $415 million and $447 million were outstanding, respectively.

In addition, Continental Wind has a $122 million letter of credit facility and $4 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2020, the Continental Wind letter of credit facility had $114 million in letters of credit outstanding related to the project.

In 2017, Generation's interests in Continental Wind were contributed to EGRP. Refer to Note 23 - Variable Interest Entities for additional information on EGRP.

Renewable Power Generation. In March 2016, RPG, an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for paydown of long term debt obligations at Sacramento PV Energy and Constellation

Solar Horizons and for general business purposes. The loan is scheduled to mature on March 31, 2035. The term loan bears interest at a fixed rate of 4.11% payable semi-annually. As of December 31, 2020 and December 31, 2019, approximately $95 million and $106 million were outstanding, respectively.

In 2017, Generation's interests in RPG were contributed to EGRP. Refer to Note 23 - Variable Interest Entities for additional information on EGRP.

SolGen, LLC. In September 2016, SolGen, an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 30, 2036. The term loan bears interest at a fixed rate of 3.93% payable semi-annually. As of December 31, 2020 and December 31, 2019, approximately $ 125 million and $131 million were outstanding, respectively. As a result of the sale agreement with an affiliate of Brookfield Renewable in the fourth quarter of 2020, the outstanding balance was reclassified to Liabilities held for sale in Exelon's and Generation's Consolidated Balance Sheets as of December 31, 2020. In 2017, Generation's interests in SolGen were contributed to and were pledged as collateral for the EGR IV financing structure. In December 2020, as part of the EGR IV financing, SolGen was removed from the collateral terms structured within the agreement. See EGR IV discussed below for additional information and Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the sale agreement.

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 with a maturity date of November 28, 2024. In addition to the financing, EGR IV entered into interest rate swaps with an initial notional amount of $636 million at an interest rate of 2.32% to manage a portion of the interest rate exposure in connection with the financing.

In December 2020, EGR IV entered into a financing agreement for a $750 million nonrecourse senior secured term loan credit facility, scheduled to mature on December 15, 2027. The term loan bears interest at a variable rate equal to LIBOR plus 2.75%, subject to a 1% LIBOR floor with interest payable quarterly. In addition to the financing, EGR IV entered into interest rate swaps with an initial notional amount of $516 million at an interest rate of 1.05% to manage a portion of the interest rate exposure in connection with the financing.

The proceeds were used to repay the November 2017 nonrecourse senior secured term loan credit facility of $850 million, of which $709 million was outstanding as of the retirement date in December of 2020, and to settle the November 2017 interest rate swap. Generation's interests in EGRP and Antelope Valley remained contributed to and are pledged as collateral for this financing. As of December 31, 2020, $750 million was outstanding. See Note 23 — Variable Interest Entities for additional information on EGRP and Note 16 — Derivative Financial Instruments for additional information on interest rate swaps.

18. Fair Value of Financial Assets and Liabilities (All Registrants)

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

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

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of December 31, 2020 and 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.

	December 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	$ 36,912	$ 40,688	$ 3,064	$ 43,752	$ 36,039	$ 37,453	$ 2,580	$ 40,033
Generation	6,087	5,648	1,208	6,856	7,974	7,304	1,366	8,670
ComEd	8,983	11,117	—	11,117	8,491	9,848	—	9,848
PECO	3,753	4,553	50	4,603	3,405	3,868	50	3,918
BGE	3,664	4,366	—	4,366	3,270	3,649	—	3,649
PHI	7,006	6,099	1,806	7,905	6,563	5,902	1,164	7,066
Pepco	3,165	3,336	748	4,084	2,864	3,198	388	3,586
DPL	1,677	1,484	455	1,939	1,567	1,408	311	1,719
ACE	1,413	1,018	602	1,620	1,327	1,026	464	1,490
Long-Term Debt to Financing Trusts(a)								
Exelon	$ 390	$ —	$ 467	$ 467	$ 390	$ —	$ 428	$ 428
ComEd	205	—	246	246	205	—	227	227
PECO	184	—	221	221	184	—	201	201
SNF Obligation								
Exelon	$ 1,208	$ 909	$ —	$ 909	$ 1,199	$ 1,055	$ —	$ 1,055
Generation	1,208	909	—	909	1,199	1,055	—	1,055

(a) Includes unamortized debt issuance costs which are not fair valued. Refer to Note 17 — Debt and Credit Agreements for each Registrants' unamortized debt issuance costs.

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

Type	Level	Registrants	Valuation
Long-Term Debt, including amounts due within one year			
Taxable Debt Securities	2	All	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. Exelon obtains credit spreads based on trades of existing Exelon 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	Exelon, Generation, DPL	Debt rates are reset on a regular basis and the carrying value approximates fair value.
Taxable Private Placement Debt Securities	3	Exelon, Pepco, DPL, ACE	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.
Government Backed Fixed Rate Project Financing Debt	3	Exelon, Generation	The fair value is similar to the process for taxable debt securities. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable U.S. Treasury rate as well as a current market curve derived from government-backed securities.
Non-Government Backed Fixed Rate Nonrecourse Debt	3	Exelon, Generation, Pepco	Fair value is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project.
Long-Term Debt to Financing Trusts			
Long Term Debt to Financing Trusts	3	Exelon, ComEd, PECO	Fair value is based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities and qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.
SNF Obligation			
SNF Obligation	2	Exelon, Generation	The carrying amount is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation is calculated by compounding the current book value of the SNF obligation at the 13-week U.S. Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2035 and 2030 for the years ended December 31, 2020 and 2019, respectively.

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 December 31, 2020 and 2019:

Exelon and Generation

	Exelon					Generation				
As of December 31, 2020	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents[(a)]	$ 686	$ —	$ —	$ —	$ 686	$ 124	$ —	$ —	$ —	$ 124
NDT fund investments										
Cash equivalents[(b)]	210	95	—	—	305	210	95	—	—	305
Equities	3,886	2,077	—	1,562	7,525	3,886	2,077	—	1,562	7,525
Fixed income										
Corporate debt[(c)]	—	1,485	285	—	1,770	—	1,485	285	—	1,770
U.S. Treasury and agencies	1,871	126	—	—	1,997	1,871	126	—	—	1,997
Foreign governments	—	56	—	—	56	—	56	—	—	56
State and municipal debt	—	101	—	—	101	—	101	—	—	101
Other	—	41	—	961	1,002	—	41	—	961	1,002
Fixed income subtotal	1,871	1,809	285	961	4,926	1,871	1,809	285	961	4,926
Private credit	—	—	212	629	841	—	—	212	629	841
Private equity	—	—	—	504	504	—	—	—	504	504
Real estate	—	—	—	679	679	—	—	—	679	679
NDT fund investments subtotal[(d)(e)]	5,967	3,981	497	4,335	14,780	5,967	3,981	497	4,335	14,780
Rabbi trust investments										
Cash equivalents	60	—	—	—	60	4	—	—	—	4
Mutual funds	91	—	—	—	91	29	—	—	—	29
Fixed income	—	11	—	—	11	—	—	—	—	—
Life insurance contracts	—	87	34	—	121	—	28	—	—	28
Rabbi trust investments subtotal	151	98	34	—	283	33	28	—	—	61
Investments in equities[(f)]	195	—	—	—	195	195	—	—	—	195
Commodity derivative assets										
Economic hedges	745	1,914	1,599	—	4,258	745	1,914	1,599	—	4,258
Proprietary trading	—	17	27	—	44	—	17	27	—	44
Effect of netting and allocation of collateral[(g)(h)]	(607)	(1,597)	(905)	—	(3,109)	(607)	(1,597)	(905)	—	(3,109)
Commodity derivative assets subtotal	138	334	721	—	1,193	138	334	721	—	1,193
DPP consideration	—	639	—	—	639	—	639	—	—	639
Total assets	7,137	5,052	1,252	4,335	17,776	6,457	4,982	1,218	4,335	16,992
Liabilities										
Commodity derivative liabilities										
Economic hedges	(682)	(1,928)	(1,655)	—	(4,265)	(682)	(1,928)	(1,354)	—	(3,964)
Proprietary trading	—	(21)	(4)	—	(25)	—	(21)	(4)	—	(25)
Effect of netting and allocation of collateral[(g)(h)]	540	1,918	1,067	—	3,525	540	1,918	1,067	—	3,525
Commodity derivative liabilities subtotal	(142)	(31)	(592)	—	(765)	(142)	(31)	(291)	—	(464)
Deferred compensation obligation	—	(145)	—	—	(145)	—	(42)	—	—	(42)
Total liabilities	(142)	(176)	(592)	—	(910)	(142)	(73)	(291)	—	(506)
Total net assets	$ 6,995	$ 4,876	$ 660	$ 4,335	$ 16,866	$ 6,315	$ 4,909	$ 927	$ 4,335	$ 16,486

	Exelon					Generation				
As of December 31, 2019	**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	1,801	—	1,388	6,542	3,353	1,801	—	1,388	6,542
Fixed income										
Corporate debt[(c)]	—	1,421	257	—	1,678	—	1,421	257	—	1,678
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	—	33	—	953	986	—	33	—	953	986
Fixed income subtotal	1,808	1,717	257	953	4,735	1,808	1,717	257	953	4,735
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)(e)]	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[(g)(h)]	(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
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[(g)(h)]	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 $409 million and $373 million at December 31, 2020 and 2019, respectively, and restricted cash of $59 million and $110 million at December 31, 2020 and 2019, respectively, and includes long-term restricted cash of $53 million and $177 million at December 31, 2020 and 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Generation excludes cash of $171 million and $177 million at December 31, 2020 and 2019, respectively, and restricted cash of $20 million and $58 million at December 31, 2020 and 2019, respectively.

(b) Includes $116 million and $90 million of cash received from outstanding repurchase agreements at December 31, 2020 and 2019, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (e) below.

(c) Includes investments in equities sold short of $(62) million and $(48) million as of December 31, 2020 and 2019, respectively, held in an investment vehicle primarily to hedge the equity option component of its convertible debt.

(d) Includes derivative assets of $2 million and $2 million, which have total notional amounts of $1,043 million and $724 million at December 31, 2020 and 2019, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of Exelon and Generation's exposure to credit or market loss.

(e) Excludes net liabilities of $181 million and $147 million at December 31, 2020 and 2019, respectively, which include certain derivative assets that have notional amounts of $104 million and $99 million at December 31, 2020 and 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.

(f) Reflects equity investments held by Generation which were previously designated as equity investments without readily determinable fair values but are now publicly traded and therefore have readily determinable fair values. Generation recorded the fair value of these investments in Other current assets on Exelon's and Generation's Consolidated Balance Sheets based on the quoted market prices of the stocks at December 31, 2020, which resulted in an unrealized gain of $186 million within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income for the year ended December 31, 2020.

(g) Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $(67) million, $321 million, and $162 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2020. 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.

(h) Of the collateral posted/(received), $209 million and $511 million represents variation margin on the exchanges as of December 31, 2020 and 2019, respectively.

As of December 31, 2020, Exelon and Generation have outstanding commitments to invest in private credit, private equity, and real estate investments of approximately $195 million, $254 million, and $369 million, respectively. These commitments will be funded by Generation's existing NDT funds.

Exelon and Generation held investments without readily determinable fair values with carrying amounts of $73 million and $55 million as of December 31, 2020, respectively. Exelon and Generation held investments without readily determinable fair values with carrying amounts of $69 million as of December 31, 2019. Changes in fair value, cumulative adjustments, and impairments were not material for the years ended December 31, 2020 and December 31, 2019.

ComEd, PECO, and BGE

	ComEd				PECO				BGE			
As of December 31, 2020	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 285	$ —	$ —	$ 285	$ 8	$ —	$ —	$ 8	$ 120	$ —	$ —	$ 120
Rabbi trust investments												
Mutual funds	—	—	—	—	9	—	—	9	10	—	—	10
Life insurance contracts	—	—	—	—	—	13	—	13	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	9	13	—	22	10	—	—	10
Total assets	285	—	—	285	17	13	—	30	130	—	—	130
Liabilities												
Mark-to-market derivative liabilities[(b)]	—	—	(301)	(301)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(9)	—	(9)	—	(5)	—	(5)
Total liabilities	—	(8)	(301)	(309)	—	(9)	—	(9)	—	(5)	—	(5)
Total net assets (liabilities)	$ 285	$ (8)	$ (301)	$ (24)	$ 17	$ 4	$ —	$ 21	$ 130	$ (5)	$ —	$ 125

	ComEd				PECO				BGE			
As of December 31, 2019	**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												
Mark-to-market derivative liabilities[(b)]	—	—	(301)	(301)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(9)	—	(9)	—	(5)	—	(5)
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 $83 million and $90 million at December 31, 2020 and 2019, respectively, and restricted cash of $37 million and $33 million at December 31, 2020 and 2019, respectively, and includes long-term restricted cash of $43 million and $163 million at December 31, 2020 and 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of $18 million and $12 million at December 31, 2020 and 2019, respectively. BGE excludes cash of $24 million at both December 31, 2020 and 2019, respectively, and restricted cash of $1 million at both December 31, 2020 and 2019, respectively.

(b) The Level 3 balance consists of the current and noncurrent liability of $33 million and $268 million, respectively, at December 31, 2020 and $32 million and $269 million, respectively, at December 31, 2019 related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

PHI, Pepco, DPL, and ACE

	As of December 31, 2020				As of December 31, 2019			
PHI	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[(a)]	$ 86	$ —	$ —	$ 86	$ 124	$ —	$ —	$ 124
Rabbi trust investments								
Cash equivalents	55	—	—	55	44	—	—	44
Mutual funds	14	—	—	14	14	—	—	14
Fixed income	—	11	—	11	—	12	—	12
Life insurance contracts	—	26	34	60	—	24	41	65
Rabbi trust investments subtotal	69	37	34	140	58	36	41	135
Total assets	155	37	34	226	182	36	41	259
Liabilities								
Deferred compensation obligation	—	(17)	—	(17)	—	(19)	—	(19)
Total liabilities	—	(17)	—	(17)	—	(19)	—	(19)
Total net assets	$ 155	$ 20	$ 34	$ 209	$ 182	$ 17	$ 41	$ 240

	Pepco				DPL				ACE			
As of December 31, 2020	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 35	$ —	$ —	$ 35	$ —	$ —	$ —	$ —	$ 13	$ —	$ —	$ 13
Rabbi trust investments												
Cash equivalents	53	—	—	53	—	—	—	—	—	—	—	—
Fixed income	—	2	—	2	—	—	—	—	—	—	—	—
Life insurance contracts	—	26	34	60	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	53	28	34	115	—	—	—	—	—	—	—	—
Total assets	88	28	34	150	—	—	—	—	13	—	—	13
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets	$ 88	$ 26	$ 34	$ 148	$ —	$ —	$ —	$ —	$ 13	$ —	$ —	$ 13

	Pepco				DPL				ACE			
As of December 31, 2019	**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	$ 77	$ 24	$ 41	$ 142	$ —	$ —	$ —	$ —	$ 16	$ —	$ —	$ 16

(a) PHI excludes cash of $74 million and $57 million at December 31, 2020 and 2019, respectively, and includes long-term restricted cash of $10 million and $14 million at December 31, 2020 and 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Pepco excludes cash of $30 million and $29 million at December 31, 2020 and 2019, respectively. DPL excludes cash of $15 million and $13 million at December 31, 2020 and 2019, respectively. ACE excludes cash of $17 million and $12 million at December 31, 2020 and 2019, respectively, and includes long-term restricted cash of $10 million and $14 million at December 31, 2020 and 2019, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets.

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2020 and 2019:

	Exelon	Generation			ComEd	PHI and Pepco	
For the year ended December 31, 2020	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
Balance as of January 1, 2020	$ 1,068	$ 511	$ 817	$ 1,328	$ (301)	$ 41	$ —
Total realized / unrealized gains (losses)							
Included in net income	(409)	2	(414) (a)	(412)	—	3	—
Included in noncurrent payables to affiliates	—	21	—	21	—	—	(21)
Included in regulatory assets/liabilities	21	—	—	—	— (b)	—	21
Change in collateral	(53)	—	(53)	(53)	—	—	—
Purchases, sales, issuances and settlements							
Purchases	151	8	143	151	—	—	—
Sales	(27)	—	(27)	(27)	—	—	—
Settlements	(55)	(45)	—	(45)	—	(10)	—
Transfers into Level 3	(12)	—	(12) (c)	(12)	—	—	—
Transfers out of Level 3	(24)	—	(24) (c)	(24)	—	—	—
Balance as of December 31, 2020	$ 660	$ 497	$ 430	$ 927	$ (301)	$ 34	$ —
The amount of total gains included in net income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2020	$ 11	$ 2	$ 6	$ 8	$ —	$ 3	$ —

	Exelon	Generation			ComEd	PHI and Pepco	
For the year ended December 31, 2019	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
Balance as of January 1, 2019	$ 907	$ 543	$ 575	$ 1,118	$ (249)	$ 38	$ —
Total realized / unrealized gains (losses)							
Included in net income	(23)	5	(31) (a)	(26)	—	3	—
Included in noncurrent payables to affiliates	—	34	—	34	—	—	(34)
Included in regulatory assets/liabilities	(18)	—	—	—	(52) (b)	—	34
Change in collateral	138	—	138	138	—	—	—
Purchases, sales, issuances and settlements							
Purchases	176	44	132	176	—	—	—
Sales	(23)	(21)	(2)	(23)	—	—	—
Settlements	(89)	(94)	5	(89)	—	—	—
Transfers into Level 3	5	—	5 (c)	5	—	—	—
Transfers out of Level 3	(5)	—	(5) (c)	(5)	—	—	—
Balance as of December 31, 2019	$ 1,068	$ 511	$ 817	$ 1,328	$ (301)	$ 41	$ —
The amount of total gains included in net income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2019	$ 359	$ 5	$ 351	$ 356	$ —	$ 3	$ —

(a) Includes a reduction for the reclassification of $420 million and $377 million of realized gains due to the settlement of derivative contracts for the years ended December 31, 2020 and 2019, respectively.

(b) Includes $33 million of decreases in fair value and an increase for realized losses due to settlements of $33 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2020. Includes $78 million of decreases in fair value and an increase for realized losses due to settlements of $26 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 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 years ended December 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 (losses) gains included in net income for the year ended December 31, 2020	$ (404)	$ (10)	$ 3	$ 2	$ (404)	$ (10)	$ 2	$ 3
Change in unrealized (losses) gains relating to assets and liabilities held for the year ended December 31, 2020	(31)	37	3	2	(31)	37	2	3

	Exelon				Generation			PHI and Pepco
	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance
Total gains (losses) included in net income for the year ended December 31, 2019	$ 219	$ (245)	$ 3	$ 5	$ 219	$ (245)	$ 5	$ 3
Change in unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2019	546	(195)	3	5	546	(195)	5	3

Valuation Techniques Used to Determine Fair Value

Cash Equivalents (All Registrants). 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.

NDT Fund Investments (Exelon and Generation). The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in equities and fixed income. Generation's and CENG's NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments, including private credit, private equity, and real estate. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

Equities. These investments consist of individually held equity securities, equity mutual funds, and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Exelon and Generation are able to independently corroborate. Equity securities held individually, including real estate investment trusts, rights, and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. The equity securities that are held directly by the trust funds are valued based on quoted prices in active markets and categorized as Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies, and fund investments are held in accordance with a stated set of fund objectives. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly or more frequently, with 30 or less days of notice and without further restrictions.

Fixed income. For fixed income securities, which consist primarily of corporate debt securities, U.S. government securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds, and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class, or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon and Generation have obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon and Generation selectively corroborate the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Other fixed income investments primarily consist of fixed income commingled funds and mutual funds, which are maintained by investment companies and hold fund investments in accordance with a stated set of fund objectives. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly or more frequently, with 30 or less days of notice and without further restrictions.

Derivative instruments. These instruments, consisting primarily of futures and swaps to manage risk, are recorded at fair value. Over-the-counter derivatives are valued daily, based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over-the-counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Private credit. Private credit investments primarily consist of investments in private debt strategies. These investments are generally less liquid assets with an underlying term of 3 to 5 years and are intended to be held to maturity. The fair value of these investments is determined by the fund manager or administrator 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 credit investments held directly by Exelon and Generation are categorized as Level 3 because they are based largely on inputs that are unobservable and utilize complex valuation models. 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. Managed private credit fund investments are not classified within the fair value hierarchy because their fair value is determined using NAV or its equivalent as a practical expedient.

Private equity. These investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments, and investments in natural resources. 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 valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include unobservable inputs such as cost, operating results, discounted future cash flows, and market based comparable data. These valuation inputs are unobservable. The fair value of private equity investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Real estate. These investments are funds with a direct investment in pools of real estate properties. These funds are reported by the fund manager and are generally based on independent appraisals from sources with professional qualifications, typically using a combination of market comparables and discounted cash flows. These valuation inputs are unobservable. The fair value of real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of December 31, 2020. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2020, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.

See Note 10 — Asset Retirement Obligations for additional information on the NDT fund investments. See Note 15 — Retirement Benefits for the valuation techniques used for hedge fund investments.

Rabbi Trust Investments (Exelon, Generation, PECO, BGE, PHI, Pepco, DPL, and ACE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The Rabbi trusts' assets are included in investments in the Registrants' Consolidated Balance Sheets and consist 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 Exelon relies on its third-party insurance provider to develop the inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Exelon. Therefore, Exelon has not disclosed such inputs.

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

The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the tables above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

Investments in Equities (Exelon and Generation). Exelon and Generation hold certain investments in equity securities with readily determinable fair values in addition to those held within the NDT funds. These equity securities are valued based on quoted prices in active markets and are categorized as Level 1.

Deferred Purchase Price Consideration (Exelon and Generation). Exelon and Generation have DPP consideration for the sale of certain receivables of retail electricity at Generation. This amount is valued based on the sales price of the receivables net of allowance for credit losses based on accounts receivable aging historical experience coupled with specific identification through a credit monitoring process, which considers current 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. Since the DPP consideration is based on the sales price of the receivables, it is categorized as Level 2 in the fair value hierarchy. See Note 6 — Accounts Receivable for additional information on the sale of certain receivables.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd). 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 the Registrants believe 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 Registrants' 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. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data, in their 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.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties, and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.49 and $0.38 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 16 — Derivative Financial Instruments for additional information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

See Note 16 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

The following table presents the significant inputs to the forward curve used to value these positions:

Type of trade	Fair Value at December 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)	$ 245	$ 558	Discounted Cash Flow	Forward power price	$2.25	-	$163	$30	$9	-	$180	$29
				Forward gas price	$1.57	-	$7.88	$2.59	$0.83	-	$10.72	$2.55
			Option Model	Volatility percentage	11%	-	237%	32%	8%	-	236%	70%
Mark-to-market derivatives— Proprietary trading (Exelon and Generation)(a)(b)	$ 23	$ 45	Discounted Cash Flow	Forward power price	$10	-	$106	$27	$25	-	$180	$33
Mark-to-market derivatives (Exelon and ComEd)	$ (301)	$ (301)	Discounted Cash Flow	Forward heat rate(c)	8x	-	9x	8.85x	9x	-	10x	9.68x
				Marketability reserve	3%	-	8%	4.93%	3%	-	7%	4.95%
				Renewable factor	91%	-	123%	99%	91%	-	123%	99%

(a) The valuation techniques, unobservable inputs, ranges, and arithmetic averages are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on level three positions of $162 million and $214 million as of December 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.

19. Commitments and Contingencies (All Registrants)

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 December 31, 2020:

Description	Exelon	PHI	Pepco	DPL	ACE
Total commitments	$ 513	$ 320	$ 120	$ 89	$ 111
Remaining commitments[(a)]	82	67	55	7	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 $135 million, which will generate future earnings at Exelon and Generation. Investment costs, which are expected to be primarily capital in nature, are recognized as incurred and recorded in Exelon's and Generation's financial statements. As of December 31, 2020, 27 MWs of new generation were developed and Exelon and Generation have incurred costs of $119 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 March 2019. The third and final 40 MW wind REC tranche will be conducted in 2022.

Commercial Commitments (All Registrants). The Registrants' commercial commitments as of December 31, 2020, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
Exelon	**Total**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026 and beyond**
Letters of credit	$ 1,243	$ 1,179	$ 50	$ 14	$ —	$ —	$ —
Surety bonds(a)	1,070	1,017	53	—	—	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values(b)	28	2	3	3	6	5	9
Total commercial commitments	$ 2,719	$ 2,198	$ 106	$ 17	$ 6	$ 5	$ 387
Generation							
Letters of credit	$ 1,228	$ 1,164	$ 50	$ 14	$ —	$ —	$ —
Surety bonds(a)	926	873	53	—	—	—	—
Total commercial commitments	$ 2,154	$ 2,037	$ 103	$ 14	$ —	$ —	$ —
ComEd							
Letters of credit	$ 7	$ 7	$ —	$ —	$ —	$ —	$ —
Surety bonds(a)	16	16	—	—	—	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	$ 223	$ 23	$ —	$ —	$ —	$ —	$ 200
PECO							
Surety bonds(a)	$ 2	$ 2	$ —	$ —	$ —	$ —	$ —
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	$ 180	$ 2	$ —	$ —	$ —	$ —	$ 178
BGE							
Letters of credit	$ 2	$ 2	$ —	$ —	$ —	$ —	$ —
Surety bonds(a)	3	3	—	—	—	—	—
Total commercial commitments	$ 5	$ 5	$ —	$ —	$ —	$ —	$ —
PHI							
Surety bonds(a)	$ 22	$ 22	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values(b)	28	2	3	3	6	5	9
Total commercial commitments	$ 50	$ 24	$ 3	$ 3	$ 6	$ 5	$ 9
Pepco							
Surety bonds(a)	$ 14	$ 14	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values(b)	9	—	1	1	2	2	3
Total commercial commitments	$ 23	$ 14	$ 1	$ 1	$ 2	$ 2	$ 3
DPL							
Surety bonds(a)	$ 4	$ 4	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values(b)	12	1	1	1	3	2	4
Total commercial commitments	$ 16	$ 5	$ 1	$ 1	$ 3	$ 2	$ 4
ACE							
Surety bonds(a)	$ 4	$ 4	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values(b)	7	1	1	1	1	1	2
Total commercial commitments	$ 11	$ 5	$ 1	$ 1	$ 1	$ 1	$ 2

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

(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The lease term associated with these assets ranges from 1 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $71 million guaranteed by Exelon and PHI, of which $24 million, $30 million, and $17 million is guaranteed by Pepco, DPL, and ACE, respectively. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Nuclear Insurance (Exelon and Generation)

Generation is subject to liability, property damage, and other risks associated with major incidents at any of its nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2020, the current liability limit per incident is $13.8 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors at least once every five years with the last adjustment effective November 1, 2018. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. Effective January 1, 2017, the required amount of nuclear energy liability insurance purchased is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool, as required by the Price Anderson-Act, which provides the additional $13.3 billion per incident in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Generation's share of this secondary layer would be approximately $2.9 billion, however any amounts payable under this secondary layer would be capped at $434 million per year.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.8 billion limit for a single incident.

As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates 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. See Note 23 — Variable Interest Entities for additional information on Generation's operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years, NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. Generation's portion of the annual distribution declared by NEIL is estimated to be $75 million for 2020, and was $136 million and $58 million for 2019 and 2018, respectively. In addition, in March 2018, NEIL declared a supplemental distribution. Generation's portion of the supplemental distribution declared by NEIL was $31 million. The distributions were recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

Premiums paid to NEIL by its members are also subject to a potential assessment for adverse loss experience in the form of a retrospective premium obligation. NEIL has never assessed this retrospective premium since its formation in 1973, and Generation cannot predict the level of future assessments, if any. The current maximum aggregate annual retrospective premium obligation for Generation is approximately $252 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides “all risk” property damage, decontamination, and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery by Generation will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity, and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon’s and Generation’s financial statements.

Spent Nuclear Fuel Obligation (Exelon and Generation)

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation’s nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation historically had paid the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. Due to the lack of a viable disposal program, the DOE reduced the SNF disposal fee to zero in May 2014. Until a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. This fee may be adjusted prospectively to ensure full cost recovery.

Generation currently assumes the DOE will begin accepting SNF in 2035 and uses that date for purposes of estimating the nuclear decommissioning asset retirement obligations. The SNF acceptance date assumption is based on management’s estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage.

The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance is expected to be delayed significantly. In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government’s breach, for costs associated with storage of SNF at Generation’s nuclear stations pending the DOE’s fulfillment of its obligations. Generation’s settlement agreement does not include FitzPatrick and FitzPatrick does not currently have a settlement agreement in place. Calvert Cliffs, Ginna, and Nine Mile Point each have separate settlement agreements in place with the DOE which were extended during 2020 to provide for the reimbursement of SNF storage costs through December 31, 2022. Generation submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the settlement agreements, Generation received total cumulative cash reimbursements of $1,455 million through December 31, 2020 for costs incurred. After considering the amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek, Generation received net cumulative cash reimbursements of $1,266 million. As of December 31, 2020 and 2019, the amount of SNF storage costs for which reimbursement has been or will be requested from the DOE under the DOE settlement agreements is as follows:

	December 31, 2020	December 31, 2019
DOE receivable - current[a]	$ 129	$ 249
DOE receivable - noncurrent[b]	70	30
Amounts owed to co-owners[c]	(23)	(37)

(a) Recorded in Accounts receivable, other.
(b) Recorded in Deferred debits and other assets, other.
(c) Recorded in Accounts receivable, other. Represents amounts owed to the co-owners of Peach Bottom, Quad Cities, and Nine Mile Point Unit 2 generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The below table outlines the SNF liability recorded at Exelon and Generation as of December 31, 2020 and 2019:

	December 31, 2020	December 31, 2019
Former ComEd units[a]	$ 1,082	$ 1,075
Fitzpatrick[b]	126	124
Total SNF Obligation	$ 1,208	$ 1,199

(a) ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. The unfunded liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of Exelon's 2001 corporate restructuring.
(b) A prior owner of FitzPatrick elected to defer payment of the one-time fee of $34 million, with interest to the date of payment, for the FitzPatrick unit. As part of the FitzPatrick acquisition on March 31, 2017, Generation assumed a SNF liability for the DOE one-time fee obligation with interest related to FitzPatrick along with an offsetting asset, included in Other deferred debits and other assets, for the contractual right to reimbursement from NYPA, a prior owner of FitzPatrick, for amounts paid for the FitzPatrick DOE one-time fee obligation.

Interest for Exelon's and Generation's SNF liabilities accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect for calculation of the interest accrual at December 31, 2020 was 0.096% for the deferred amount transferred from ComEd and 0.101% for the deferred FitzPatrick amount.

The following table summarizes sites for which Exelon and Generation do not have an outstanding SNF Obligation:

Description	Sites
Fees have been paid	Former PECO units, Clinton and Calvert Cliffs
Outstanding SNF Obligation remains with former owners	Nine Mile Point, Ginna and TMI

Environmental Remediation Matters

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

MGP Sites (Exelon and the Utility Registrants). ComEd, PECO, BGE, and DPL have identified sites where former MGP or gas purification activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has 21 sites that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2026.
- PECO has 8 sites that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2023.
- BGE has 4 sites that currently require some level of remediation and/or ongoing activity. BGE expects the majority of the remediation at these sites to continue through at least 2023.
- DPL has 1 site that is currently under study and the required cost at the site is not expected to be material.

The historical nature of the MGP and gas purification sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. While BGE and DPL do not have riders for MGP clean-up costs, they have historically received recovery of actual clean-up costs in distribution rates.

As of December 31, 2020 and 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:

	December 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	$ 483	$ 314	$ 478	$ 320
Generation	121	—	105	—
ComEd	293	293	304	303
PECO	23	21	19	17
BGE	2	—	2	—
PHI	44	—	48	—
Pepco	42	—	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 2008 ROD required only that the radiological materials and other wastes at the site be capped, the 2018 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 have sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's financial statements.

In January 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. In September 2018, the PRPs agreed to an Administrative Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater Remedial 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 $30 million. Generation determined a loss associated with the RI/FS is probable and has recorded a liability, included in the table above, that reflects management's best estimate of Cotter's allocable share of the cost among the PRPs. At this time Generation cannot predict the likelihood that, or the extent to which any, remediation activities may be required and therefore cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's future financial statements.

In August 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's (now Generation's) indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until August 31, 2021 so that settlement discussions can proceed. On August 3, 2020, the DOJ advised Cotter and the other PRPs that it is seeking approximately $90 million from all the PRPs and has directed that the PRPs must submit a good faith joint proposed settlement offer. Generation has determined that a loss associated with this matter is probable under its indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above.

Benning Road Site (Exelon, Generation, PHI, and Pepco). In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility, which was deactivated in June 2012. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River.

Since 2013, Pepco and Pepco Energy Services (now Generation, pursuant to Exelon's 2016 acquisition of PHI) have been performing RI work and have submitted multiple draft RI reports to the DOEE. In September 2019, Pepco and Generation issued a draft "final" RI report which DOEE approved on February 3, 2020. Pepco and Generation are developing a FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the FS, and approval by the DOEE, by September 16, 2021. After completion and approval of the FS, DOEE will prepare a Proposed Plan for public comment and then issue a ROD identifying any further response actions determined to be necessary. PHI, Pepco, and Generation have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

Anacostia River Tidal Reach (Exelon, PHI, and Pepco). Contemporaneous with the Benning Road site RI/FS being performed by Pepco and Generation, DOEE and the National Park Service have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-District of Columbia boundary line to the confluence of the Anacostia and Potomac Rivers. The river-wide RI incorporated the results of the river sampling performed by Pepco and Pepco Energy Services as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by DOEE's contractor. In April 2018, DOEE released a draft RI report for public review and comment. Pepco submitted written comments on the draft RI and participated in a public hearing.

Pepco has determined that it is probable that costs for remediation will be incurred and recorded a liability in the third quarter 2019 for management's best estimate of its share of those costs. On September 30, 2020, DOEE released its Interim ROD. The Interim ROD reflects an adaptive management approach which will require several 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 has concluded that incremental exposure remains reasonably possible, but management cannot reasonably estimate a range of loss beyond the amounts recorded, which are included in the table above.

In addition to the activities associated with the remedial process outlined above, CERCLA separately requires federal and state (here including Washington, D.C.) Natural Resource Trustees (federal or state agencies designated by the President or the relevant state, respectively, or Indian tribes) to conduct an assessment of any damages to natural resources within their jurisdiction as a result of the contamination that is being remediated. The Trustees can seek compensation from responsible parties for such damages, including restoration costs. During the second quarter of 2018, Pepco became aware that the Trustees are in the beginning stages of a Natural Resources Damages (NRD) assessment, a process that often takes many years beyond the remedial decision to complete. Pepco has concluded that a loss associated with the eventual NRD assessment is reasonably possible. Due to the very early stage of the assessment process, Pepco cannot reasonably estimate the range of loss.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon and Generation). Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2020 and 2019, Exelon and Generation recorded estimated liabilities of approximately $89 million and $83 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2020, approximately $25 million of this amount related to 261 open claims presented to Generation, while the remaining $64 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2055, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether adjustments to the estimated liabilities are necessary.

It is reasonably possible that additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued could have a material, unfavorable impact on Exelon's and Generation's financial statements. However, management cannot reasonably estimate a range of loss beyond the amounts recorded.

Fund Transfer Restrictions (All Registrants). Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

Under applicable law, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, or ACE may limit the dividends that these companies can distribute to Exelon.

ComEd has agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to restrictions established by the MDPSC that prohibit BGE from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. No such event has occurred.

Pepco is subject to certain dividend restrictions established by settlements approved in Maryland and the District of Columbia. Pepco is prohibited from paying a dividend on its common shares if (a) after the dividend payment, Pepco's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the MDPSC and DCPSC or (b) Pepco's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. No such event has occurred.

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.

ACE is subject to certain dividend restrictions established by settlements approved in New Jersey. ACE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, ACE's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the NJBPU or (b) ACE's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. ACE is also subject to a dividend restriction which requires ACE to obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%. No such events have occurred.

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 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 TIF Agreement on June 30, 2020, could be material to Generation's financial statements.

Deferred Prosecution Agreement (DPA) and Related Matters (Exelon and ComEd). Exelon and ComEd received a grand jury subpoena in the second quarter of 2019 from the U.S. Attorney's Office for the Northern District of Illinois (USAO) requiring production of information concerning their lobbying activities in the State of Illinois. On October 4, 2019, Exelon and ComEd received a second grand jury subpoena from the USAO requiring production of records of any communications with certain individuals and entities. On October 22, 2019, the SEC notified Exelon and ComEd that it had also opened an investigation into their lobbying activities. On July 17, 2020, ComEd entered into a DPA with the USAO to resolve the USAO investigation. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the Speaker of the Illinois House of Representatives and the Speaker's associates, with the intent to influence the Speaker's action regarding legislation affecting ComEd's interests. The DPA provides that the USAO will defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period subject to certain obligations of ComEd, including payment to the U.S. Treasury of $200 million, with $100 million payable within thirty days of the filing of the DPA with the United States District Court for the Northern District of Illinois and an additional $100 million within ninety days of such filing date. The payments were recorded within Operating and maintenance expense in Exelon's and ComEd's Consolidated Statements of Operations and Comprehensive Income in the second quarter of 2020. The payments will not be recovered in rates or charged to customers and ComEd will not seek or accept reimbursement or indemnification from any source other than Exelon. Exelon made equity contributions to ComEd of $200 million in 2020. On August 13, 2020, a motion was filed in the U.S. District Court for the Northern District of Illinois by a ComEd customer and on behalf of ComEd customers seeking to enjoin ComEd from paying these funds to the U.S. Treasury and requiring the U.S. government to establish a victims' restitution fund from which the $200 million would be disbursed to ComEd customers. The motion was denied without prejudice on November 6, 2020 and ComEd submitted the $200 million payment to the U.S. Treasury. On January 6, 2021, the customer petitioned the Seventh Circuit for a writ of mandamus to seek review of the district court's ruling, but on January 8, 2021, the Seventh Circuit denied the petition. On January 22, 2021, the customer petitioned the Seventh Circuit for rehearing of its denial of his petition for a writ of mandamus. On February 5, 2021, the Seventh Circuit denied the petition for rehearing.

Exelon was not made a party to the DPA, and therefore the investigation by the USAO into Exelon's activities ended with no charges being brought against Exelon.

The SEC's investigation remains ongoing and Exelon and ComEd have cooperated fully and intend to continue to cooperate fully with the SEC. Exelon and ComEd cannot predict the outcome of the SEC investigation. No loss contingency has been reflected in Exelon's and ComEd's consolidated financial statements with respect to the SEC investigation, as this contingency is neither probable nor reasonably estimable at this time.

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

- A putative class action lawsuit against Exelon and certain officers of Exelon and ComEd was filed in federal court in December 2019 alleging misrepresentations and omissions in Exelon's SEC filings related to ComEd's lobbying activities and the related investigations. The complaint was amended on September 16, 2020, to dismiss two of the original defendants and add other defendants, including ComEd. Defendants filed a motion to dismiss in November 2020. Briefing was completed on February 17, 2021.

- A derivative shareholder lawsuit was filed against Exelon, its directors and certain officers of Exelon and ComEd in April 2020 alleging, among other things, breaches of fiduciary duties also purporting to relate to matters that are the subject of the subpoenas and the SEC investigation. The plaintiff voluntarily dismissed this derivative action without prejudice to refile on July 28, 2020.

- Three putative class action lawsuits against ComEd and Exelon were filed in Illinois state court in the third quarter of 2020 seeking restitution and compensatory damages on behalf of ComEd customers. These three state cases were consolidated into a single action in October of 2020. In addition, on November 2, 2020, the Citizens Utility Board (CUB) filed a motion to intervene in the state cases pursuant to an Illinois statute allowing CUB to intervene as a party or otherwise participate on behalf of utility consumers in any proceeding which affects the interest of utility consumers. On November 23, 2020, the court allowed CUB's intervention, but denied CUB's request to stay these cases. Plaintiffs subsequently filed a consolidated complaint, and ComEd and Exelon filed a motion to dismiss on jurisdictional and substantive grounds on January 11, 2021. Briefing on that motion is ongoing.

- Four putative class action lawsuits against ComEd and Exelon were filed in federal court in the third quarter of 2020 alleging, among other things, civil violations of federal racketeering laws. In addition, CUB filed a motion to intervene in these cases on October 22, 2020 which was granted on December 23, 2020. In addition, on December 2, 2020, the court appointed interim lead plaintiffs in the federal cases which consisted of counsel for three of the four federal cases. These plaintiffs filed a consolidated complaint on January 5, 2021. CUB also filed its own complaint against ComEd only on the same day. The remaining federal case, Potter, et al. v. Exelon et al, differed from the other lawsuits as it named additional individual defendants not named in the consolidated complaint. On January 10, 2021, the Potter plaintiffs filed a motion asking the court to clarify that their class action complaint against ComEd, Exelon and the individual named defendants remains in effect, notwithstanding the consolidated amended complaint, and asked the court to stay the Potter case. On January 21, 2021, the court determined that the appointed lead counsel had sole discretion to determine which parties to name as plaintiffs and defendants, and that the Potter plaintiffs have the option to opt-out of that class and file a separate, individual action against the defendants named in their original complaint. The Potter plaintiffs have until March 23, 2021 to make that decision.

- Four shareholders sent letters to the Exelon Board of Directors in 2020 demanding, among other things, that the Exelon Board of Directors investigate and address alleged breaches of fiduciary duties and other alleged violations by Exelon and ComEd officers and directors related to the conduct described in the DPA.

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

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.

20. Shareholders' Equity (Exelon and Utility Registrants)

ComEd Common Stock Warrants

The following table presents warrants outstanding to purchase ComEd common stock and shares of common stock reserved for the conversion of warrants. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants.

	December 31,	
	2020	2019
Warrants outstanding	60,143	60,228
Common Stock reserved for conversion	20,048	20,076

Share Repurchases

There currently is no Exelon Board of Director authority to repurchase shares. Any previous shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon’s management.

Preferred and Preference Securities

The following table presents Exelon, ComEd, PECO, BGE, Pepco, and ACE's shares of preferred securities authorized, none of which were outstanding as of December 31, 2020 and 2019. There are no shares of preferred securities authorized for DPL.

	Preferred Securities Authorized
Exelon	100,000,000
ComEd	850,000
PECO	15,000,000
BGE	1,000,000
Pepco	6,000,000
ACE[(a)]	2,799,979

(a) Includes 799,979 shares of cumulative preferred stock and 2,000,000 of no-par preferred stock as of December 31, 2020 and 2019.

The following table presents ComEd's, BGE's, and ACE's preference securities authorized, none of which were outstanding as of December 31, 2020 and 2019. There are no shares of preference securities authorized for Exelon, PECO, Pepco, and DPL.

	Preference Securities Authorized
ComEd	6,810,451
BGE[(a)]	6,500,000
ACE	3,000,000

(a) Includes 4,600,000 shares of unclassified preference securities and 1,900,000 shares of previously redeemed preference securities as of December 31, 2020 and 2019.

21. Stock-Based Compensation Plans (All Registrants)

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes performance share awards, restricted stock units, and stock options. At December 31, 2020, there were approximately 34 million shares authorized for issuance under the LTIP. For the years ended December 31, 2020, 2019, and 2018, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

The Registrants grant cash awards. The following table does not include expense related to these plans as they are not considered stock-based compensation plans under the applicable authoritative guidance.

The following table presents the stock-based compensation expense included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The Utility Registrants' stock-based compensation expense for the years ended December 31, 2020, 2019, and 2018 was not material.

	Year Ended December 31,		
Exelon	**2020**	**2019**	**2018**
Total stock-based compensation expense included in operating and maintenance expense	$ 64	$ 77	$ 208
Income tax benefit	(16)	(20)	(54)
Total after-tax stock-based compensation expense	$ 48	$ 57	$ 154
Generation			
Total stock-based compensation expense included in operating and maintenance expense	$ 27	$ 37	$ 77
Income tax benefit	(7)	(10)	(20)
Total after-tax stock-based compensation expense	$ 20	$ 27	$ 57

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The following table presents information regarding Exelon’s realized tax benefit when distributed:

	Year Ended December 31,		
	2020	**2019**	**2018**
Performance share awards	$ 21	$ 41	$ 16
Restricted stock units	15	24	28

Performance Share Awards

Performance share awards are granted under the LTIP. The performance share awards are settled 50% in common stock and 50% in cash at the end of the three-year performance period, except for awards granted to vice presidents and higher officers that are settled 100% in cash if certain ownership requirements are satisfied.

The common stock portion of the performance share awards is considered an equity award and is valued based on Exelon's stock price on the grant date. The cash portion of the performance share awards is considered a liability award which is remeasured each reporting period based on Exelon’s current stock price. As the value of the common stock and cash portions of the awards are based on Exelon’s stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the straight-line method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant.

Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon’s nonvested performance share awards activity:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2019[(a)]	1,709,755	$ 39.21
Granted	1,122,378	46.61
Change in performance	(751,309)	42.51
Vested	(747,551)	35.70
Forfeited	(67,964)	45.59
Undistributed vested awards[(b)]	(334,917)	50.76
Nonvested at December 31, 2020[(a)]	930,392	$ 43.67

(a) Excludes 1,414,661 and 2,017,870 of performance share awards issued to retirement-eligible employees as of December 31, 2020 and 2019, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2020.

The following table summarizes the weighted average grant date fair value and the total fair value of performance share awards vested.

	Year Ended December 31,		
	2020[(a)]	2019	2018
Weighted average grant date fair value (per share)	$ 46.61	$ 47.37	$ 38.15
Total fair value of performance shares vested	39	158	61
Total fair value of performance shares settled in cash	63	131	49

(a) As of December 31, 2020, $13 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.8 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized ratably over the first six months in the year of grant if the employee reaches retirement eligibility prior to July 1st of the grant year or through the date of which the employee reaches retirement eligibility. Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon’s nonvested restricted stock unit activity:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2019[(a)]	1,498,713	$ 40.35
Granted	847,382	46.33
Vested	(725,151)	38.38
Forfeited	(52,046)	45.20
Undistributed vested awards[(b)]	(454,768)	45.91
Nonvested at December 31, 2020[(a)]	1,114,130	$ 43.67

(a) Excludes 748,165 and 863,196 of restricted stock units issued to retirement-eligible employees as of December 31, 2020 and 2019, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2020.

The following table summarizes the weighted average grant date fair value and the total fair value of restricted stock units vested.

	Year Ended December 31,		
	2020[a]	2019	2018
Weighted average grant date fair value (per share)	$ 46.33	$ 45.65	$ 38.60
Total fair value of restricted stock units vested	54	92	106

(a) As of December 31, 2020, $23 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.3 years.

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock were granted through 2012 under the LTIP. The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. Stock options will expire no later than ten years from the date of grant.

At December 31, 2020 all stock options were vested and there were no unrecognized compensation costs.

The following table presents information with respect to stock option activity:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2019	1,889,045	$ 40.43	1.56	$ 10
Options exercised	(475,827)	38.30		5
Options expired	(147,808)	46.07		
Balance of shares outstanding at December 31, 2020	1,265,410	$ 40.57	0.91	$ 3
Exercisable at December 31, 2020[a]	1,265,410	$ 40.57	0.91	$ 3

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised:

	Year Ended December 31,		
	2020	2019	2018
Intrinsic value[a]	$ 5	$ 9	$ 12
Cash received for exercise price	18	59	56

(a) The difference between the market value on the date of exercise and the option exercise price.

22. Changes in Accumulated Other Comprehensive Income (Exelon)

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

	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items [(a)]	Foreign Currency Items	AOCI of Investments Unconsolidated Affiliates [(b)]	Total
Balance at December 31, 2017	$ (14)	$ 10	$ (2,998)	$ (23)	$ (1)	$ (3,026)
OCI before reclassifications	11	—	(143)	(10)	1	(141)
Amounts reclassified from AOCI	1	—	181	—	—	182
Net current-period OCI	12	—	38	(10)	1	41
Impact of adoption of Recognition and Measurement of Financial Assets and Financial Liabilities standard[(c)]	—	(10)	—	—	—	(10)
Balance at December 31, 2018	$ (2)	$ —	$ (2,960)	$ (33)	$ —	$ (2,995)
OCI before reclassifications	—	—	(289)	6	(2)	(285)
Amounts reclassified from AOCI	—	—	84	—	2	86
Net current-period OCI	—	—	(205)	6	—	(199)
Balance at December 31, 2019	$ (2)	$ —	$ (3,165)	$ (27)	$ —	$ (3,194)
OCI before reclassifications	(3)	—	(357)	4	—	(356)
Amounts reclassified from AOCI	—	—	150	—	—	150
Net current-period OCI	(3)	—	(207)	4	—	(206)
Balance at December 31, 2020	$ (5)	$ —	$ (3,372)	$ (23)	$ —	$ (3,400)

(a) This AOCI component is included in the computation of net periodic pension and OPEB cost. See Note 15 — 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.

(c) Exelon adopted the new standard Recognition and Measurement of Financial Assets and Financial Liabilities. The standard was adopted as of January 1, 2018, which resulted in an increase to Retained earnings and Accumulated other comprehensive loss of $10 million for Exelon. The amounts reclassified related to Rabbi Trusts.

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

	For the Year Ended December 31,		
	2020	2019	2018
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	$ 16	$ 23	$ 24
Actuarial loss reclassified to periodic benefit cost	(66)	(52)	(86)
Pension and non-pension postretirement benefit plans valuation adjustment	122	100	50

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

At December 31, 2020 and 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 December 31, 2020 and 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 footnotes to the table below, are such that creditors, or beneficiaries, do not have recourse to the general credit of Exelon, Generation, PHI, and ACE.

	December 31, 2020				December 31, 2019			
	Exelon	Generation	PHI[(a)]	ACE	Exelon	Generation	PHI[(a)]	ACE
Cash and cash equivalents	$ 98	$ 98	$ —	$ —	$ 163	$ 163	$ —	$ —
Restricted cash and cash equivalents	47	44	3	3	88	85	3	3
Accounts receivable								
Customer	148	148	—	—	151	151	—	—
Other	36	36	—	—	39	39	—	—
Unamortized energy contract assets	22	22	—	—	23	23	—	—
Inventories, net								
Materials and supplies	244	244	—	—	227	227	—	—
Assets held for sale[(b)]	101	101	—	—	—	—	—	—
Other current assets	674	669	5	—	32	31	1	—
Total current assets	1,370	1,362	8	3	723	719	4	3
Property, plant and equipment, net	5,803	5,803	—	—	6,022	6,022	—	—
Nuclear decommissioning trust funds	3,007	3,007	—	—	2,741	2,741	—	—
Unamortized energy contract assets	249	249	—	—	250	250	—	—
Other noncurrent assets	52	42	10	10	89	73	16	14
Total noncurrent assets	9,111	9,101	10	10	9,102	9,086	16	14
Total assets[(c)]	$ 10,481	$ 10,463	$ 18	$ 13	$ 9,825	$ 9,805	$ 20	$ 17
Long-term debt due within one year	$ 94	$ 68	$ 26	$ 21	$ 544	$ 523	$ 21	$ 20
Accounts payable	81	81	—	—	106	106	—	—
Accrued expenses	70	70	—	—	70	70	—	—
Unamortized energy contract liabilities	4	4	—	—	8	8	—	—
Liabilities held for sale[(b)]	16	16	—	—	—	—	—	—
Other current liabilities	5	5	—	—	3	3	—	—
Total current liabilities	270	244	26	21	731	710	21	20
Long-term debt	889	889	—	—	527	504	23	21
Asset retirement obligations	2,318	2,318	—	—	2,128	2,128	—	—
Unamortized energy contract liabilities	—	—	—	—	1	1	—	—
Other noncurrent liabilities	129	129	—	—	89	89	—	—
Total noncurrent liabilities	3,336	3,336	—	—	2,745	2,722	23	21
Total liabilities[(d)]	$ 3,606	$ 3,580	$ 26	$ 21	$ 3,476	$ 3,432	$ 44	$ 41

(a) Includes certain purchase accounting adjustments from the PHI merger not pushed down to ACE.

(b) Generation entered into an agreement for the sale of a significant portion of Generation's solar business. As a result of this transaction, in the fourth quarter of 2020, Exelon and Generation reclassified the consolidated VIEs' solar assets and liabilities as held for sale. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the sale of the solar business.

(c) Exelon's and Generation's balances include unrestricted assets for current unamortized energy contract assets of $22 million and $23 million, Property, plant, and equipment of $1 million and $20 million, non-current unamortized energy contract assets of $249 million and $250 million, and Assets held for sale of $9 million and $0 million as of December 31, 2020 and 2019, respectively.

(d) Exelon's and Generation's balances include liabilities with recourse of $8 million and $3 million as of December 31, 2020 and 2019, respectively.

As of December 31, 2020 and 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 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. Refer to Note 12 — Asset Impairments 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.
NER - A bankruptcy remote, special purpose entity which is 100% owned by Generation, which purchases certain of Generation's customer accounts receivable arising from the sale of retail electricity. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. Refer to Note 6 — Accounts Receivable for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	Generation conducts all activities.

CENG - On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the NOSA pursuant to which Generation conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF.

EDF has the option to sell its 49.99% equity interest in CENG to Generation. On November 20, 2019, Generation received notice of EDF's intention to exercise the put option to sell its interest in CENG to Generation and the put automatically exercised on January 19, 2020. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

Exelon and Generation, where indicated, provide the following support to CENG:

- Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. See Note 19 — Commitments and Contingencies for more details,
- Generation and EDF share in the $688 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance, and
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

EGRP - EGRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by EGRP. Generation owns a number of limited liability companies that build, own, and operate solar and wind power facilities some of which are owned by EGRP. While Generation or EGRP owns 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that certain of the solar and wind entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of these solar and wind entities that qualify as VIEs because Generation controls the design, construction, and operation of the facilities. There is limited recourse to Generation related to certain solar and wind entities.

In 2017, Generation's interests in EGRP were contributed to and are pledged for the EGR IV non-recourse debt project financing structure. Refer to Note 17 — Debt and Credit Agreements for additional information.

As of December 31, 2020 and 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 Funding - A special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of Transition Bonds. Proceeds from the sale of each series of Transition Bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on Transition Bonds and related taxes, expenses, and fees.	ACE's equity investment is a variable interest as, by design, it absorbs any initial variability of ATF. The bondholders also have a variable interest for the investment made to purchase the Transition Bonds.	ACE controls the servicing activities.

Unconsolidated VIEs

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected in Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements.

As of December 31, 2020 and 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.

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

	December 31, 2020			December 31, 2019		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 777	$ 401	$ 1,178	$ 636	$ 443	$ 1,079
Total liabilities[(a)]	61	223	284	33	227	260
Exelon's ownership interest in VIE[(a)]	—	157	157	—	191	191
Other ownership interests in VIE[(a)]	716	21	737	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 December 31, 2020 and 2019.

As of December 31, 2020 and 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. Refer to Note 12 — Asset Impairments 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.

24. 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.

	Taxes other than income taxes								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020									
Utility[(a)]	$ 859	$ 99	$ 238	$ 135	$ 87	$ 299	$ 275	$ 21	$ 3
Property	602	265	30	16	164	126	84	39	3
Payroll	235	113	27	16	17	25	7	5	3
For the year ended December 31, 2019									
Utility[(a)]	$ 881	$ 112	$ 242	$ 132	$ 90	$ 304	$ 286	$ 18	$ —
Property	595	274	29	17	153	122	85	34	2
Payroll	232	115	27	15	17	24	7	4	2
For the year ended December 31, 2018									
Utility[(a)]	$ 919	$ 114	$ 243	$ 131	$ 94	$ 337	$ 316	$ 21	$ —
Property	557	273	30	15	143	94	58	32	3
Payroll	247	130	27	16	17	24	5	3	2

(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.

	Other, Net								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020									
Decommissioning-related activities:									
Net realized income on NDT funds(a)									
Regulatory Agreement Units	$ 185	$ 185	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory Agreement Units	160	160	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory Agreement Units	724	724	—	—	—	—	—	—	—
Non-regulatory Agreement Units	391	391	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities(b)	(729)	(729)	—	—	—	—	—	—	—
Decommissioning-related activities	731	731	—	—	—	—	—	—	—
AFUDC—Equity	104	—	29	17	22	36	28	4	4
Non-service net periodic benefit cost	53	—	—	—	—	—	—	—	—
Unrealized gains from equity investments(c)	186	186	—	—	—	—	—	—	—
For the year ended December 31, 2019									
Decommissioning-related activities:									
Net realized income on NDT funds(a)									
Regulatory Agreement Units	$ 297	$ 297	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory Agreement Units	363	363	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory Agreement Units	795	795	—	—	—	—	—	—	—
Non-regulatory Agreement Units	411	411	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities(b)	(876)	(876)	—	—	—	—	—	—	—
Decommissioning-related activities	990	990	—	—	—	—	—	—	—
AFUDC—Equity	85	—	17	13	21	34	25	4	5
Non-service net periodic benefit cost	13	—	—	—	—	—	—	—	—
For the year ended December 31, 2018									
Decommissioning-related activities:									
Net realized income on NDT funds(a)									
Regulatory Agreement Units	$ 506	$ 506	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory Agreement Units	302	302	—	—	—	—	—	—	—
Net unrealized losses on NDT funds									
Regulatory Agreement Units	(715)	(715)	—	—	—	—	—	—	—
Non-regulatory Agreement Units	(483)	(483)	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities(b)	171	171	—	—	—	—	—	—	—
Decommissioning-related activities	(219)	(219)	—	—	—	—	—	—	—
AFUDC—Equity	69	—	19	7	18	25	22	2	1
Non-service net periodic benefit cost	(47)	—	—	—	—	—	—	—	—

(a) Realized income includes interest, dividends, and realized gains and losses on sales of NDT fund investments.

(b) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of income taxes related to all NDT fund activity for those units. See Note 10 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) Unrealized gains resulting from equity investments without readily determinable fair values that became publicly traded entities in the fourth quarter of 2020 and were fair valued based on quoted market prices of the stocks as of December 31, 2020.

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**
For the year ended December 31, 2020									
Property, plant, and equipment(a)	$ 4,364	$ 2,070	$ 922	$ 319	$ 397	$ 586	$ 257	$ 155	$ 140
Amortization of regulatory assets(a)	588	—	211	28	153	196	120	36	40
Amortization of intangible assets, net(a)	62	53	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities(b)	30	30	—	—	—	—	—	—	—
Nuclear fuel(c)	983	983	—	—	—	—	—	—	—
ARO accretion(d)	500	500	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 6,527	$ 3,636	$ 1,133	$ 347	$ 550	$ 782	$ 377	$ 191	$ 180
For the year ended December 31, 2019									
Property, plant, and equipment(a)	$ 3,665	$ 1,485	$ 886	$ 303	$ 359	$ 547	$ 239	$ 146	$ 123
Amortization of regulatory assets(a)	528	—	147	30	143	207	135	38	34
Amortization of intangible assets, net(a)	59	50	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities(b)	21	21	—	—	—	—	—	—	—
Nuclear fuel(c)	1,016	1,016	—	—	—	—	—	—	—
ARO accretion(d)	491	491	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 5,780	$ 3,063	$ 1,033	$ 333	$ 502	$ 754	$ 374	$ 184	$ 157
For the year ended December 31, 2018									
Property, plant, and equipment(a)	$ 3,740	$ 1,748	$ 820	$ 274	$ 335	$ 480	$ 218	$ 131	$ 94
Amortization of regulatory assets(a)	555	—	120	27	148	260	167	51	42
Amortization of intangible assets, net(a)	58	49	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities(b)	14	14	—	—	—	—	—	—	—
Nuclear fuel(c)	1,115	1,115	—	—	—	—	—	—	—
ARO accretion(d)	489	489	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 5,971	$ 3,415	$ 940	$ 301	$ 483	$ 740	$ 385	$ 182	$ 136

(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.

	Cash paid (refunded) during the year:								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020									
Interest (net of amount capitalized)	$ 1,521	$ 331	$ 371	$ 144	$ 125	$ 257	$ 129	$ 61	$ 57
Income taxes (net of refunds)	10	70	(61)	(37)	(57)	46	40	12	(3)
For the year ended December 31, 2019									
Interest (net of amount capitalized)	$ 1,470	$ 373	$ 343	$ 129	$ 106	$ 255	$ 130	$ 59	$ 55
Income taxes (net of refunds)	265	(44)	(42)	82	17	29	7	19	(5)
For the year ended December 31, 2018									
Interest (net of amount capitalized)	$ 1,421	$ 369	$ 332	$ 125	$ 94	$ 250	$ 123	$ 56	$ 61
Income taxes (net of refunds)	95	746	(153)	(2)	14	(32)	41	(6)	(12)

	Other non-cash operating activities:								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2020									
Pension and non-pension postretirement benefit costs	$ 411	$ 115	$ 114	$ 5	$ 62	$ 70	$ 15	$ 7	$ 14
Allowance for credit losses	150	17	32	42	15	43	24	16	2
Other decommissioning-related activity(a)	(659)	(659)	—	—	—	—	—	—	—
Energy-related options(b)	104	104	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates(c)	(6)	—	47	(16)	(16)	(21)	(40)	7	12
Severance costs	105	90	1	1	—	—	—	—	—
Provision for excess and obsolete inventory	131	128	2	1	—	—	—	—	—
Long-term incentive plan	56	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	222	155	2	1	31	28	7	8	3
Asset impairments	—	—	15	—	—	13	—	7	6
AFUDC - Equity	(104)	—	(29)	(17)	(22)	(36)	(28)	(4)	(4)
For the year ended December 31, 2019									
Pension and non-pension postretirement benefit costs	$ 438	$ 135	$ 96	$ 12	$ 61	$ 95	$ 25	$ 15	$ 16
Allowance for credit losses	120	31	33	31	8	17	7	4	5
Other decommissioning-related activity(a)	(506)	(506)	—	—	—	—	—	—	—
Energy-related options(b)	22	22	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates(d)	124	—	128	—	—	(4)	(4)	—	—
Long-term incentive plan	10	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	244	172	3	—	30	33	8	8	4
Change in environmental liabilities	23	—	—	—	—	23	23	—	—
AFUDC - Equity	(85)	—	(17)	(13)	(21)	(34)	(25)	(4)	(5)
For the year ended December 31, 2018									
Pension and non-pension postretirement benefit costs	$ 583	$ 204	$ 177	$ 18	$ 59	$ 67	$ 15	$ 6	$ 12
Allowance for credit losses	159	48	40	33	10	28	11	6	11
Other decommissioning-related activity(a)	(2)	(2)	—	—	—	—	—	—	—
Energy-related options(b)	10	10	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates(d)	49	—	28	—	—	21	21	—	—
Asset retirement costs	20	—	—	—	—	20	22	(1)	(1)
Long-term incentive plan	140	—	—	—	—	—	—	—	—
AFUDC - Equity	(69)	—	(19)	(7)	(18)	(25)	(22)	(2)	(1)

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of operating revenues, ARO updates and accretion, ARC amortization, investment income, and income taxes related to all NDT fund activity for these units. See Note 10 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

(c) For ComEd, reflects the true-up adjustments in regulatory assets and liabilities associated with its distribution, energy efficiency, distributed generation, and transmission formula rates. For BGE, Pepco, and DPL, reflects the change in regulatory assets and liabilities associated with their decoupling mechanisms and transmission formula rates. For PECO and ACE, reflects the change in regulatory assets and liabilities associated with their transmission formula rates. See Note 3 — Regulatory Matters for additional information.

(d) For ComEd, reflects the true-up adjustments in regulatory assets and liabilities associated with its distribution and energy efficiency formula rates. For Pepco and DPL, reflects the change in regulatory assets and liabilities associated with their decoupling mechanisms. See Note 3 — Regulatory Matters for additional information.

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

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2020									
Cash and cash equivalents	$ 663	$ 226	$ 83	$ 19	$ 144	$ 111	$ 30	$ 15	$ 17
Restricted cash and cash equivalents	438	89	279	7	1	39	35	—	3
Restricted cash included in other long-term assets	53	—	43	—	—	10	—	—	10
Cash, restricted cash, and cash equivalents - Held for Sale	12	12	—	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,166	$ 327	$ 405	$ 26	$ 145	$ 160	$ 65	$ 15	$ 30
December 31, 2019									
Cash and cash equivalents	$ 587	$ 303	$ 90	$ 21	$ 24	$ 131	$ 30	$ 13	$ 12
Restricted cash and cash equivalents	358	146	150	6	1	36	33	—	2
Restricted cash included in other long-term assets	177	—	163	—	—	14	—	—	14
Total cash, restricted cash, and cash equivalents	$ 1,122	$ 449	$ 403	$ 27	$ 25	$ 181	$ 63	$ 13	$ 28
December 31, 2018									
Cash and cash equivalents	$ 1,349	$ 750	$ 135	$ 130	$ 7	$ 124	$ 16	$ 23	$ 7
Restricted cash and cash equivalents	247	153	29	5	6	43	37	1	4
Restricted cash included in other long-term assets	185	—	166	—	—	19	—	—	19
Total cash, restricted cash, and cash equivalents	$ 1,781	$ 903	$ 330	$ 135	$ 13	$ 186	$ 53	$ 24	$ 30
December 31, 2017									
Cash and cash equivalents	$ 898	$ 416	$ 76	$ 271	$ 17	$ 30	$ 5	$ 2	$ 2
Restricted cash and cash equivalents	207	138	5	4	1	42	35	—	6
Restricted cash included in other long-term assets	85	—	63	—	—	23	—	—	23
Total cash, restricted cash, and cash equivalents	$ 1,190	$ 554	$ 144	$ 275	$ 18	$ 95	$ 40	$ 2	$ 31

Supplemental Balance Sheet Information

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

	Investments								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2020									
Equity method investments:									
Other equity method investments	$ 81	$ 65	$ 6	$ 8	$ —	$ —	$ —	$ —	$ —
Other investments:									
Employee benefit trusts and investments(a)	283	61	—	22	10	140	115	—	—
Equity investments without readily determinable fair values	73	55	—	—	—	—	—	—	—
Other available for sale debt security investments	3	3	—	—	—	—	—	—	—
Total investments	$ 440	$ 184	$ 6	$ 30	$ 10	$ 140	$ 115	$ —	$ —
December 31, 2019									
Equity method investments:									
Other equity method investments	$ 92	$ 71	$ 6	$ 8	$ —	$ —	$ —	$ —	$ —
Other investments:									
Employee benefit trusts and investments(a)	262	54	—	19	7	135	110	—	—
Equity investments without readily determinable fair values	69	69	—	—	—	—	—	—	—
Other available for sale debt security investments	41	41	—	—	—	—	—	—	—
Total investments	$ 464	$ 235	$ 6	$ 27	$ 7	$ 135	$ 110	$ —	$ —

(a) The Registrants' debt and equity security investments are recorded at fair market value.

	Accrued expenses								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2020									
Compensation-related accruals(a)	$ 1,069	$ 426	$ 170	$ 73	$ 84	$ 109	$ 36	$ 18	$ 17
Taxes accrued	527	229	94	16	73	117	90	18	12
Interest accrued	331	44	109	37	46	51	26	7	12
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.

25. 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:

	For the Years Ended December 31,		
	2020	2019	2018
Operating revenues from affiliates:			
ComEd[(a)(b)]	$ 330	$ 369	$ 523
PECO[(c)]	190	158	128
BGE[(d)]	315	289	260
PHI	367	353	355
Pepco[(e)]	279	264	206
DPL[(f)]	75	70	120
ACE[(g)]	13	19	29
Other	9	3	2
Total operating revenues from affiliates (Generation)	$ 1,211	$ 1,172	$ 1,268

(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 2020, ComEd's Purchased power from Generation of $345 million is recorded as Operating revenues from ComEd of $330 million and Purchased power and fuel from ComEd of $15 million at Generation. For 2019, ComEd's Purchased power from Generation of $376 million is recorded as Operating revenues from ComEd of $369 million and Purchased power and fuel from ComEd of $7 million at Generation.
(c) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has a ten-year agreement with PECO to sell solar AECs.
(d) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs.
(e) Generation provides electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.
(f) Generation provides a portion of DPL's energy requirements under its MDPSC and DPSC approved market based SOS commodity programs.
(g) Generation provides electric supply to ACE under contracts executed through ACE's competitive procurement process.

PHI

PHI's Operating revenues from affiliates are primarily with BSC for services that PHISCO provides to BSC.

Operating and maintenance expense from affiliates

The Registrants receive a variety of corporate support services from BSC. Pepco, DPL, and ACE also receive corporate support services from PHISCO. See Note 1 - Significant Accounting Policies for additional information regarding BSC and PHISCO.

The following table presents the service company costs allocated to the Registrants:

	Operating and maintenance from affiliates			Capitalized costs		
	For the years ended December 31,			For the years ended December 31,		
	2020	2019	2018	2020	2019	2018
Exelon						
BSC				$ 585	$ 516	$ 448
PHISCO				61	72	79
Generation						
BSC	$ 552	$ 570	$ 652	54	66	67
ComEd						
BSC	283	263	265	186	148	135
PECO						
BSC	150	149	146	76	88	64
BGE						
BSC	170	157	157	132	126	79
PHI						
BSC	152	139	147	149	88	102
PHISCO	—	—	—	61	72	79
Pepco						
BSC	85	85	89	55	38	40
PHISCO	120	124	137	27	33	32
DPL						
BSC	54	52	51	51	25	28
PHISCO	97	100	111	18	20	25
ACE						
BSC	45	42	42	40	19	20
PHISCO	87	90	98	16	19	21

Current Receivables from/Payables to affiliates

The following tables present current receivables from affiliates and current payables to affiliates:

December 31, 2020

	Receivables from affiliates:										
Payables to affiliates:	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	BSC	PHISCO	Other	Total
Generation		$ 13	$ —	$ —	$ —	$ —	$ —	$ 72	$ —	$ 22	$ 107
ComEd	$ 78 (a)		—	—	—	—	—	59	—	9	146
PECO	17	1		—	—	—	—	28	—	4	50
BGE	11	—	—		—	—	—	47	—	3	61
PHI	—	—	—	—	—	—	—	4	—	11	15
Pepco	13	2	—	1		—	—	25	14	—	55
DPL	3	1	—	—	—		—	21	10	1	36
ACE	6	—	—	—	—	—		15	9	1	31
Other	25	5	2	2	2	1	6	—	—		43
Total	$ 153	$ 22	$ 2	$ 3	$ 2	$ 1	$ 6	$ 271	$ 33	$ 51	$ 544

December 31, 2019

	Receivables from affiliates:								
Payables to affiliates:	**Generation**	**ComEd**	**PECO**	**BGE**	**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 December 31, 2020 and 2019, Generation also had a contract liability with ComEd for $50 million and $37 million, respectively, that was included in Other liabilities on Generation's Consolidated Balance Sheets. At December 31, 2020 and 2019, ComEd had a Current Payable to Generation of $28 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

Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 10 — Asset Retirement Obligations 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:

	December 31,	
	2020	**2019**
ComEd	$ 2,541	$ 2,622
PECO	475	480

Long-term debt to financing trusts

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

	As of December 31,					
	2020			**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	$ 390	$ 205	$ 184	$ 390	$ 205	$ 184

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.

26. Subsequent Events (Exelon and Generation)

Planned Separation

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies. Under the separation plan, Exelon shareholders will retain their current shares of Exelon stock and receive a pro-rata distribution of shares of the new company's stock in a transaction that is expected to be tax-free to Exelon and its shareholders for U.S. federal income tax purposes. The actual number of shares to be distributed to Exelon shareholders will be determined prior to closing.

Exelon is targeting to complete the separation in the first quarter of 2022, subject to final approval by Exelon's Board of Directors, a Form 10 registration statement being declared effective by the SEC, regulatory approvals, and satisfaction of other conditions. The transaction is subject to approval by the FERC, NRC, and NYPSC, and receipt of a private letter ruling from the IRS and tax opinion from Exelon's tax advisors. There can be no assurance that any separation transaction will ultimately occur or, if one does occur, of its terms or timing.

Impacts of February 2021 Weather Events and Texas-based Generating Assets Outages

Beginning on February 15, 2021, Generation's Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced periodic outages as a result of historically severe cold weather conditions. In addition, those weather conditions drove increased demand for service, limited the availability of natural gas to fuel power plants, dramatically increased wholesale power prices, and also increased gas prices in certain regions. In response to the high demand and significantly reduced total generation on the system, ERCOT implemented load reductions to maintain the reliability of the grid and required the use of an administrative price cap of $9,000 per megawatt hour during load shedding events.

Exelon and Generation estimate the impact to their Net income for the first quarter of 2021 arising from these market and weather conditions to be approximately $560 million to $710 million. The estimated impact includes favorable results in certain regions within Generation's wholesale gas business. The ultimate impact to Exelon's and Generation's consolidated financial statements may be affected by a number of factors, including final settlement data, the impacts of customer and counterparty credit losses, any state sponsored solutions to address the financial challenges caused by the event, and litigation and contract disputes which may result.

Generation used a combination of commercial paper and letters of credit to manage collateral needs and has posted approximately $1.4 billion of collateral with ERCOT as of February 22, 2021. Generation continues to believe it has sufficient cash on hand and available capacity on its revolver, which was $2.4 billion as of February 22, 2021, to meet its liquidity requirements.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

All Registrants

None.

ITEM 9A. CONTROLS AND PROCEDURES

All Registrants—Disclosure Controls and Procedures

During the fourth quarter of 2020, each registrant's management, including its principal executive officer and principal financial officer, evaluated the effectiveness of that registrant's disclosure controls and procedures related to the recording, processing, summarizing, and reporting of information in that registrant’s periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by each registrant to ensure that (a) information relating to that registrant, including its consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to that registrant’s management, including its principal executive officer and principal financial officer, by other employees of that registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated, and reported, as applicable, within the time periods specified in the SEC’s rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2020, the principal executive officer and principal financial officer of each registrant concluded that such registrant’s disclosure controls and procedures were effective to accomplish their objectives.

All Registrants—Changes in Internal Control Over Financial Reporting

Each registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2020 that have materially affected, or are reasonably likely to materially affect, any of the Registrant's internal control over financial reporting, including no changes resulting from COVID-19. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Executive Overview for additional information on COVID-19.

All Registrants—Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2020. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2020 and, therefore, concluded that each registrant’s internal control over financial reporting was effective. Management’s Report on Internal Control Over Financial Reporting is included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

ITEM 9B. OTHER INFORMATION

All Registrants

On February 22, 2021, ComEd adopted Amended and Restated Bylaws to amend the standard for independent directors.

PART III

Exelon Generation Company, LLC, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to Generation, PECO, BGE, PHI, Pepco, DPL, and ACE are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive officers of the Registrants at February 24, 2021.

Directors, Director Nomination Process and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)), and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in Exelon's definitive 2021 proxy statement (2021 Exelon Proxy Statement) and the ComEd information statement (2021 ComEd Information Statement) to be filed with the SEC on or before April 30, 2021 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to Exelon's and ComEd's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at www.exeloncorp.com. The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Carter C. Culver, Senior Vice President and Deputy General Counsel, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, www.exeloncorp.com, or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under Executive Compensation Data and Report of the Compensation Committee in the Exelon Proxy Statement for the 2021 Annual Meeting of Shareholders or the ComEd 2021 Information Statement, which are incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The additional information required by this item will be set forth under *Ownership of Exelon Stock* in the 2021 Exelon Proxy Statement or the ComEd 2021 Information Statement and incorporated herein by reference.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

	[A]	[B]	[C]
Plan Category	Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)	Weighted-average price of outstanding Options, warrants and rights (Note 2)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column [A]) (Note 3)
Equity compensation plans approved by security holders	7,130,386	$ 16.29	46,987,104

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(1) Balance includes stock options, unvested performance shares, and unvested restricted stock units that were granted under the Exelon LTIP or predecessor company plans (including shares awarded under those plans and deferred into the stock deferral plan) and deferred stock units granted to directors as part of their compensation. Unvested performance shares are subject to performance metrics and to a total shareholder return modifier. Additionally, pursuant to the terms of the Exelon LTIP plan, 50% of final payouts are made in the form of shares of common stock and 50% is made in form of in cash, or if the participant has exceeded 200% of their stock ownership requirement, 100% of the final payout is made in cash. For performance shares granted in 2018, 2019, and 2020, the total includes the maximum number of shares that could be issued assuming all participants receive 50% of payouts in shares and assuming the performance and total shareholder return modifier metrics were both at maximum, representing best case performance, for a total of 6,988,082 shares. If the performance and total shareholder return modifier metrics were at "target", the number of securities to be issued for such awards would be 3,494,041. The balance also includes 450,154 shares to be issued upon the conversion of deferred stock units awarded to members of the Exelon board of directors. Conversion of the deferred stock units to shares of common stock occurs after a director terminates service to the Exelon board or the board of any of its subsidiary companies. See Note 21 — Stock-Based Compensation Plans of the Combined Notes to Consolidated Financial Statements for additional information about the material features of the plans.

(2) The weighted-average price reported in column B does not take the performance shares and shares credited to deferred compensation plans into account.

(3) Includes 15,229,957 shares remaining available for issuance from the employee stock purchase plan and 4,729,509 shares remaining available for issuance to former Constellation employees with outstanding awards made under the prior Constellation LTIP.

No ComEd securities are authorized for issuance under equity compensation plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under Related Persons Transactions and Director Independence in the Exelon Proxy Statement for the 2021 Annual Meeting of Shareholders or the ComEd 2021 Information Statement, which are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under The Ratification of PricewaterhouseCoopers LLP as Exelon’s Independent Accountant for 2021 in the Exelon Proxy Statement for the 2021 Annual Meeting of Shareholders and the ComEd 2021 Information Statement, which are incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

(1) Exelon

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 24, 2021 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2020, 2019, and 2018

Consolidated Statements of Cash Flows for the Years Ended December 31, 2020, 2019, and 2018

Consolidated Balance Sheets at December 31, 2020 and 2019

Consolidated Statements of Changes in Equity for the Years Ended December 31, 2020, 2019, and 2018

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedules:

Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2020 and 2019 and for the Years Ended December 31, 2020, 2019, and 2018

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2020, 2019, and 2018

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Statements of Operations and Other Comprehensive Income

(In millions)	For the Years Ended December 31, 2020	2019	2018
Operating expenses			
Operating and maintenance	$ (2)	$ 33	$ (5)
Operating and maintenance from affiliates	10	9	9
Other	2	1	4
Total operating expenses	10	43	8
Operating loss	(10)	(43)	(8)
Other income and (deductions)			
Interest expense, net	(378)	(321)	(312)
Equity in earnings of investments	2,313	3,254	2,183
Interest income from affiliates, net	30	39	42
Other, net	15	14	3
Total other income	1,980	2,986	1,916
Income before income taxes	1,970	2,943	1,908
Income taxes	7	7	(97)
Net income	$ 1,963	$ 2,936	$ 2,005
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs	$ (40)	$ (64)	$ (66)
Actuarial loss reclassified to periodic cost	190	148	247
Pension and non-pension postretirement benefit plan valuation adjustment	(357)	(289)	(143)
Unrealized (loss) gain on cash flow hedges	(1)	1	12
Unrealized gain on equity investments	—	—	1
Unrealized (loss) on foreign currency translation	—	—	(10)
Other comprehensive income (loss)	(208)	(204)	41
Comprehensive income	$ 1,755	$ 2,732	$ 2,046

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2020	2019	2018
Net cash flows provided by operating activities	$ 3,018	$ 1,948	$ 2,576
Cash flows from investing activities			
Changes in Exelon intercompany money pool	(477)	95	1
Notes receivable from affiliates	550	—	—
Investment in affiliates	(1,969)	(1,071)	(1,231)
Net cash flows used in investing activities	(1,896)	(976)	(1,230)
Cash flows from financing activities			
Changes in short-term borrowings	(136)	136	—
Issuance of long-term debt	2,000	—	—
Retirement of long-term debt	(1,450)	—	—
Dividends paid on common stock	(1,492)	(1,408)	(1,332)
Proceeds from employee stock plans	45	112	105
Other financing activities	(27)	—	(4)
Net cash flows used in financing activities	(1,060)	(1,160)	(1,231)
Increase (Decrease) in cash, restricted cash, and cash equivalents	62	(188)	115
Cash, restricted cash, and cash equivalents at beginning of period	1	189	74
Cash, restricted cash, and cash equivalents at end of period	$ 63	$ 1	$ 189

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

	December 31,	
(In millions)	2020	2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 63	$ 1
Accounts receivable, net		
Other accounts receivable	354	168
Accounts receivable from affiliates	11	41
Mark-to-market derivative assets	—	3
Notes receivable from affiliates	598	679
Regulatory assets	315	253
Other	4	4
Total current assets	1,345	1,149
Property, plant, and equipment, net	46	47
Deferred debits and other assets		
Regulatory assets	3,816	3,772
Investments in affiliates	43,149	42,245
Deferred income taxes	1,625	1,524
Notes receivable from affiliates	324	329
Other	312	308
Total deferred debits and other assets	49,226	48,178
Total assets	$ 50,617	$ 49,374

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

(In millions)	December 31, 2020	December 31, 2019
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 500	$ 636
Long-term debt due within one year	300	1,458
Accounts payable	1	1
Accrued expenses	76	131
Payables to affiliates	457	363
Regulatory liabilities	4	13
Pension obligations	92	77
Other	4	10
Total current liabilities	1,434	2,689
Long-term debt	7,418	5,717
Deferred credits and other liabilities		
Regulatory liabilities	32	31
Pension obligations	8,351	7,960
Non-pension postretirement benefit obligations	387	403
Deferred income taxes	348	263
Other	62	87
Total deferred credits and other liabilities	9,180	8,744
Total liabilities	18,032	17,150
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 976 shares and 973 shares outstanding at December 31, 2020 and 2019, respectively)	19,373	19,274
Treasury stock, at cost (2 shares at December 31, 2020 and 2019)	(123)	(123)
Retained earnings	16,735	16,267
Accumulated other comprehensive loss, net	(3,400)	(3,194)
Total shareholders' equity	32,585	32,224
Total liabilities and shareholders' equity	$ 50,617	$ 49,374

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Exelon Corporation.

Exelon Corporate owns 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99%.

2. Debt and Credit Agreements

Short-Term Borrowings

Exelon Corporate meets its short-term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had no outstanding commercial paper borrowings and $136 million at December 31, 2020 and 2019, respectively.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a 12-month term loan agreement for $500 million, which was renewed annually on March 22, 2018, March 20, 2019, and March 19, 2020, respectively. The loan agreement will expire on March 18, 2021. Pursuant to the loan agreement, as of December 31, 2020, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. The loans beared interest at LIBOR plus 0.95% as of December 31, 2019 as part of the March 20, 2019 renewal. The loan agreement is reflected in Exelon's Consolidated Balance Sheet within Short-Term borrowings.

Revolving Credit Agreements

On May 26, 2018, Exelon Corporate's syndicated revolving credit facility of $600 million had its maturity date extended to May 26, 2023. As of December 31, 2020, Exelon Corporation had available capacity under those commitments of $594 million. See Note 17—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon Corporation's credit agreement.

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 as needed.

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate as of December 31, 2020 and December 31, 2019:

	Rates		Maturity Date	December 31, 2020	December 31, 2019
Long-term debt					
Junior subordinated notes		3.50 %	2022	$ 1,150	$ 1,150
Senior unsecured notes[(a)]	2.45 % -	7.60 %	2021 - 2050	6,439	5,889
Total long-term debt				7,589	7,039
Unamortized debt discount and premium, net				(10)	(7)
Unamortized debt issuance costs				(47)	(39)
Fair value adjustment				186	182
Long-term debt due within one year				(300)	(1,458)
Long-term debt				$ 7,418	$ 5,717

(a) Senior unsecured notes include mirror debt that is held on both Generation and Exelon Corporation's balance sheets.

The debt maturities for Exelon Corporate for the periods 2021, 2022, 2023, 2024, 2025, and thereafter are as follows:

2021	$ 300
2022	1,150
2023	—
2024	—
2025	807
Thereafter	5,332
Total long-term debt	$ 7,589

3. Commitments and Contingencies

See Note 19—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for Exelon Corporate’s commitments and contingencies related to environmental matters and fund transfer restrictions.

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

4. Related Party Transactions

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
(In millions)	2020	2019	2018
Operating and maintenance from affiliates:			
BSC[a]	$ 10	$ 9	$ 11
Other	—	—	(2)
Total operating and maintenance from affiliates:	$ 10	$ 9	$ 9
Interest income from affiliates, net:			
Generation	$ 29	$ 36	$ 36
BSC	1	3	4
EEDC[b]	—	—	2
Total interest income from affiliates, net:	$ 30	$ 39	$ 42
Equity in earnings (losses) of investments:			
EEDC[b]	$ 1,729	$ 2,054	$ 1,830
Generation	589	1,125	369
UII	—	97	—
PCI	—	1	(17)
Exelon Enterprises	—	(16)	—
Exelon INQB8R	(6)	(8)	—
Exelon Transmission Company	—	(2)	1
Other	1	3	—
Total equity in earnings of investments:	$ 2,313	$ 3,254	$ 2,183
Cash contributions received from affiliates	$ 3,372	$ 2,514	$ 2,302

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

	December 31,	
(in millions)	2020	2019
Accounts receivable from affiliates (current):		
BSC[(a)]	$ —	$ 11
Generation	3	13
ComEd	—	2
PECO	1	2
BGE	—	1
PHISCO	6	7
Exelon Enterprises	1	—
Exelon VTI, LLC	—	5
Total accounts receivable from affiliates (current):	$ 11	$ 41
Notes receivable from affiliates (current):		
BSC[(a)]	$ 252	$ 109
Generation[(c)]	285	558
PECO	40	—
PHI	21	12
Total notes receivable from affiliates (current):	$ 598	$ 679
Investments in affiliates:		
BSC[(a)]	$ 196	$ 197
EEDC[(b)]	30,103	28,147
Generation	12,400	13,484
PCI	62	62
UII	365	365
Voluntary Employee Beneficiary Association trust	—	(4)
Exelon Enterprises	3	6
Exelon INQB8R, LLC	23	(8)
Other	(3)	(4)
Total investments in affiliates:	$ 43,149	$ 42,245
Notes receivable from affiliates (non-current):		
Generation[(c)]	$ 324	$ 329
Accounts payable to affiliates (current):		
UII	$ 360	$ 360
BSC	91	—
EEDC[(b)]	4	—
Generation[(c)]	2	—
Exelon Enterprises	—	3
Total accounts payable to affiliates (current):	$ 457	$ 363

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology, and supply management services. All services are provided at cost, including applicable overhead.

(b) EEDC consists of ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE.

(c) 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, which are eliminated in consolidation in Exelon's Consolidated Balance Sheets.

Exelon Corporation and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2020					
Allowance for credit losses[a]	$ 294	$ 240 [b]	$ (18) [c]	$ 79 [d]	$ 437
Deferred tax valuation allowance	26	—	1	—	27
Reserve for obsolete materials	155	128 [e]	(1)	6	276
For the year ended December 31, 2019					
Allowance for credit losses[a]	$ 319	$ 119 [b]	$ 26	$ 170 [d]	$ 294
Deferred tax valuation allowance	35	—	(9)	—	26
Reserve for obsolete materials	156	6	—	7	155
For the year ended December 31, 2018					
Allowance for credit losses[a]	$ 322	$ 159 [b]	$ 35	$ 197 [d]	$ 319
Deferred tax valuation allowance	37	—	5	7	35
Reserve for obsolete materials	174	25	(31) [f]	12	156

(a) Excludes the non-current allowance for credit losses related to PECO's installment plan receivables of $5 million, $9 million, and $13 million for the years ended December 31, 2020, 2019, and 2018, respectively.
(b) The amount charged to costs and expenses includes the amount that was reclassified to regulatory assets/liabilities under different mechanisms applicable to the different jurisdictions the Utility Registrants operate in.
(c) Includes a decrease related to the sale of customer accounts receivable at Generation in the second quarter of 2020. See Note 6—Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Primarily reflects write-offs, net of recoveries of individual accounts receivable.
(e) Primarily reflects expense resulting from materials and supplies inventory reserve adjustments as a result of the decision to early retire Byron, Dresden, and Mystic 8 and 9. See Note 7—Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.
(f) Primarily reflects the reclassification of assets as held for sale at Generation.

Exelon Generation Company, LLC and Subsidiary Companies

(2) Generation

(i)	Financial Statements (Item 8):
	Report of Independent Registered Public Accounting Firm dated February 24, 2021 of PricewaterhouseCoopers LLP
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2020, 2019, and 2018
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2020, 2019, and 2018
	Consolidated Balance Sheets at December 31, 2020 and 2019
	Consolidated Statements of Changes in Equity for the Years Ended December 31, 2020, 2019, and 2018
	Notes to Consolidated Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2020, 2019, and 2018
	Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Exelon Generation Company, LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2020					
Allowance for credit losses	$ 81	$ 12	$ (56) (a)	$ 5 (b)	$ 32
Deferred tax valuation allowance	24	—	(1)	—	23
Reserve for obsolete materials	143	123 (c)	(1)	—	265
For the year ended December 31, 2019					
Allowance for credit losses	$ 104	$ 27	$ (11)	$ 39 (b)	$ 81
Deferred tax valuation allowance	26	—	(2)	—	24
Reserve for obsolete materials	145	—	—	2	143
For the year ended December 31, 2018					
Allowance for credit losses	$ 114	$ 44	$ 4	$ 58 (b)	$ 104
Deferred tax valuation allowance	23	—	3	—	26
Reserve for obsolete materials	166	20	(32) (d)	9	145

(a) Reflects the sale of customer accounts receivable at Generation in the second quarter of 2020. See Note 6—Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Write-offs, net of recoveries of individual accounts receivable.

(c) Primarily reflects expense resulting from materials and supplies inventory reserve adjustments as a result of the decision to early retire Byron, Dresden, and Mystic 8 and 9. See Note 7—Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

(d) Primarily reflects the reclassification of assets as held for sale.

Commonwealth Edison Company and Subsidiary Companies

(3) ComEd

(i)	Financial Statements (Item 8):
	Report of Independent Registered Public Accounting Firm dated February 24, 2021 of PricewaterhouseCoopers LLP
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2020, 2019, and 2018
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2020, 2019, and 2018
	Consolidated Balance Sheets at December 31, 2020 and 2019
	Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2020, 2019, and 2018
	Notes to Consolidated Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2020, 2019, and 2018
	Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Commonwealth Edison Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2020					
Allowance for credit losses	$ 79	$ 54 [(a)]	$ 13	$ 28 [(b)]	$ 118
Reserve for obsolete materials	7	3	—	4	6
For the year ended December 31, 2019					
Allowance for credit losses	$ 81	$ 35 [(a)]	$ 20	$ 57 [(b)]	$ 79
Reserve for obsolete materials	6	6	—	5	7
For the year ended December 31, 2018					
Allowance for credit losses	$ 73	$ 44 [(a)]	$ 23	$ 59 [(b)]	$ 81
Reserve for obsolete materials	5	3	1	3	6

(a) ComEd is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through a rider mechanism. The amount charged to costs and expenses includes the amount that was reclassified to regulatory assets/liabilities under such mechanism. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Write-offs, net of recoveries of individual accounts receivable.

PECO Energy Company and Subsidiary Companies

(4) PECO

(i)	Financial Statements (Item 8):
	Report of Independent Registered Public Accounting Firm dated February 24, 2021 of PricewaterhouseCoopers LLP
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2020, 2019, and 2018
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2020, 2019, and 2018
	Consolidated Balance Sheets at December 31, 2020 and 2019
	Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2020, 2019, and 2018
	Notes to Consolidated Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2020, 2019, and 2018
	Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

PECO Energy Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2020					
Allowance for credit losses(a)	$ 62	$ 76 (b)	$ 6	$ 20 (c)	$ 124
Deferred tax valuation allowance	—	—	1	—	$ 1
Reserve for obsolete materials	2	1	—	1	2
For the year ended December 31, 2019					
Allowance for credit losses(a)	$ 61	$ 31	$ 3	$ 33 (c)	$ 62
Reserve for obsolete materials	2	—	—	—	2
For the year ended December 31, 2018					
Allowance for credit losses(a)	$ 56	$ 33	$ 3	$ 31 (c)	$ 61
Reserve for obsolete materials	2	—	—	—	2

(a) Excludes the non-current allowance for credit losses related to PECO's installment plan receivables of $5 million, $9 million, and $13 million for the years ended December 31, 2020, 2019, and 2018, respectively.

(b) The amount charged to costs and expenses includes the amount that was reclassified to the COVID-19 regulatory asset. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(c) Write-offs, net of recoveries of individual accounts receivable.

Baltimore Gas and Electric Company

(5) BGE

(i)	Financial Statements (Item 8):
	Report of Independent Registered Public Accounting Firm dated February 24, 2021 of PricewaterhouseCoopers LLP
	Statements of Operations and Comprehensive Income for the Years Ended December 31, 2020, 2019 and 2018
	Statements of Cash Flows for the Years Ended December 31, 2020, 2019 and 2018
	Balance Sheets at December 31, 2020 and 2019
	Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2020, 2019 and 2018
	Notes to Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2020, 2019, and 2018
	Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Baltimore Gas and Electric Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2020					
Allowance for credit losses	$ 17	$ 31 (a)	$ 6	$ 10 (b)	$ 44
Deferred tax valuation allowance	1	—	(1)	—	—
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2019					
Allowance for credit losses	$ 20	$ 8 (a)	$ 7	$ 18 (b)	$ 17
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2018					
Allowance for credit losses	$ 24	$ 10 (a)	$ (2)	$ 12 (b)	$ 20
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	—	1	—	—	1

(a) The amount charged to costs and expenses includes the amount that was reclassified to regulatory assets/liabilities under different mechanisms as approved by the MDPSC.

(b) Write-offs, net of recoveries of individual accounts receivable.

Pepco Holdings LLC and Subsidiary Companies

(6) PHI

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 24, 2021 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2020, 2019, and 2018

Consolidated Statements of Cash Flows for the Years Ended December 31, 2020, 2019, and 2018

Consolidated Balance Sheets at December 31, 2020 and 2019

Consolidated Statements of Changes in Equity for the Years Ended December 31, 2020, 2019, and 2018

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2020, 2019, and 2018

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Pepco Holdings LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2020					
Allowance for credit losses	$ 53	$ 69 (a)	$ 13	$ 16 (b)	$ 119
Reserve for obsolete materials	3	—	—	1	2
For the year ended December 31, 2019					
Allowance for credit losses	$ 53	$ 17 (a)	$ 7	$ 24 (c)	$ 53
Deferred tax valuation allowance	8	—	(8)	—	—
Reserve for obsolete materials	2	1	—	—	3
For the year ended December 31, 2018					
Allowance for credit losses	$ 55	$ 28 (a)	$ 7	$ 37 (c)	$ 53
Deferred tax valuation allowance	13	—	2	7	8
Reserve for obsolete materials	2	—	—	—	2

(a) The amount charged to costs and expenses includes the amount that was reclassified to regulatory assets/liabilities under different mechanisms applicable to the different jurisdictions Pepco, DPL, and ACE operate in.

(b) Write-offs, net of recoveries of individual accounts receivable.

(c) Write-offs of individual accounts receivable.

Potomac Electric Power Company

(7) Pepco

(i)	Financial Statements (Item 8):
	Report of Independent Registered Public Accounting Firm dated February 24, 2021 of PricewaterhouseCoopers LLP
	Statements of Operations and Comprehensive Income for the Years Ended December 31, 2020, 2019 and 2018
	Statements of Cash Flows for the Years Ended December 31, 2020, 2019 and 2018
	Balance Sheets at December 31, 2020 and 2019
	Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2020, 2019 and 2018
	Notes to Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2020, 2019, and 2018
	Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Potomac Electric Power Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2020					
Allowance for credit losses	$ 20	$ 25 (a)	$ 5	$ 5 (b)	$ 45
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2019					
Allowance for credit losses	$ 21	$ 7 (a)	$ 2	$ 10 (c)	$ 20
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2018					
Allowance for credit losses	$ 21	$ 11 (a)	$ 3	$ 14 (c)	$ 21
Reserve for obsolete materials	1	—	—	—	1

(a) The amount charged to costs and expenses includes the amount that was reclassified to regulatory assets/liabilities under different mechanisms as approved by the DCPSC and MDPSC.

(b) Write-offs, net of recoveries of individual accounts receivable.

(c) Write-off of individual accounts receivable.

Delmarva Power & Light Company

(8) DPL

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 24, 2021 of PricewaterhouseCoopers LLP

Statements of Operations and Comprehensive Income for the Years Ended December 31, 2020, 2019 and 2018

Statements of Cash Flows for the Years Ended December 31, 2020, 2019 and 2018

Balance Sheets at December 31, 2020 and 2019

Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2020, 2019 and 2018

Notes to Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2020, 2019, and 2018

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Delmarva Power & Light Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2020					
Allowance for credit losses	$ 15	$ 16 (a)	$ 4	$ 4 (b)	$ 31
For the year ended December 31, 2019					
Allowance for credit losses	$ 13	$ 4 (a)	$ 3	$ 5 (c)	$ 15
For the year ended December 31, 2018					
Allowance for credit losses	$ 16	$ 6 (a)	$ 2	$ 11 (c)	$ 13

(a) The amount charged to costs and expenses includes the amount that was reclassified to regulatory assets/liabilities under different mechanisms as approved by the DPSC and MDPSC.

(b) Write-offs, net of recoveries of individual accounts receivable.

(c) Write-off of individual accounts receivable.

Atlantic City Electric Company and Subsidiary Company

(9) ACE

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 24, 2021 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2020, 2019, and 2018

Consolidated Statements of Cash Flows for the Years Ended December 31, 2020, 2019, and 2018

Consolidated Balance Sheets at December 31, 2020 and 2019

Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2020, 2019, and 2018

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2020, 2019, and 2018

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Atlantic City Electric Company and Subsidiary Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2020					
Allowance for credit losses	$ 18	$ 28 (a)	$ 4	$ 7 (b)	$ 43
Reserve for obsolete materials	1	—	—	1	—
For the year ended December 31, 2019					
Allowance for credit losses	$ 19	$ 5 (a)	$ 2	$ 8 (c)	$ 18
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2018					
Allowance for credit losses	$ 18	$ 11 (a)	$ 2	$ 12 (c)	$ 19
Reserve for obsolete materials	1	—	—	—	1

(a) ACE is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through the Societal Benefits Charge. The amount charged to costs and expenses includes the amount that was reclassified to regulatory assets/liabilities under such mechanism. See Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Write-offs, net of recoveries of individual accounts receivable.

(c) Write-off of individual accounts receivable.

Exhibits required by Item 601 of Regulation S-K:

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
2-1	Agreement and Plan of Merger dated as of April 28, 2011 by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc. (File No. 001-16169, Form 8-K dated April 28, 2011, Exhibit 2.1).
2-2	Distribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Constellation Energy Group, Inc. and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 2.3).
2-3	Contribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Energy Delivery Company, LLC and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 2.4).
2-4	Contribution Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Ventures Company, LLC and Exelon Generation Company, LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 2.5).
2-5	Purchase Agreement dated as of August 8, 2012 by and between Constellation Power Source Generation, Inc. and Raven Power Holdings, LLC. (File No. 333-85496, Form 10-Q dated November 7, 2012, Exhibit 2.1).
2-6	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (File No. 001-12869, Form 8-K dated November 1, 2010, Exhibit 2.1).
2-7	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (File No. 001-12869, Form 8-K dated November 8, 2010, Exhibit 2.1).
2-8	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., Baltimore Gas and Electric Company and RF HoldCo LLC. (File No. 001-12869, Form 8-K dated February 4, 2010, Exhibit 99.2).
2-9	Amended and Restated Agreement and Plan of Merger, dated as of July 18, 2014, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated July 21, 2014, Exhibit 2.1).
3-1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended July 24, 2018 (File No. 001-16169, Form 8-K dated July 27, 2018, Exhibit 3.1).
3-2	Exelon Corporation Amended and Restated Bylaws, as amended on August 3, 2020 (File No. 001-16169, Form 10-Q dated August 4, 2020, Exhibit 3.1).
3-3	Certificate of Formation of Exelon Generation Company, LLC (Registration Statement No. 333-85496, Form S-4 dated December 27, 2000, Exhibit 3.1).
3-4	Second Amended and Restated Operating Agreement of Exelon Generation Company, LLC dated of October 30, 2019 (File No. 333-85496, Form 10-Q dated October 31, 2019, Exhibit 3.1).

Exhibit No.	Description
3-5	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the "$9.00 Cumulative Preference Stock," the "$6.875 Cumulative Preference Stock" and the "$2.425 Cumulative Preference Stock" (File No. 001-01839, Form 10-K dated March 30, 1995, Exhibit 3.2).
3-6	Commonwealth Edison Company Amended and Restated By-Laws, Effective February 22, 2021.**
3-7	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 001-01401, Form 10-K dated April 2, 2001, Exhibit 3.3).
3-8	PECO Energy Company Amended and Restated Bylaws dated August 3, 2020 (File 000-16844, Form 10-Q dated August 4, 2020, Exhibit 3.3).
3-9	Articles of Amendment to the Charter of Baltimore Gas and Electric Company as of February 2, 2010. (File No. 001-01910, Form 8-K dated February 4, 2010, Exhibit 3.1).
3-10	Articles of Restatement to the Charter of Baltimore Gas and Electric Company, restated as of August 16, 1996. (File No. 001-01910, Form 10-Q dated November 14, 1996, Exhibit 3).
3-11	Amended and Restated Bylaws of Baltimore Gas and Electric Company dated August 3, 2020 (File No. 001-01910, Form 10-Q dated August 4, 2020, Exhibit 3.4).
3-12	Certificate of Formation of Pepco Holdings LLC, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 3.2).
3-13	Amended and Restated Limited Liability Company Agreement of Pepco Holdings LLC, dated August 3, 2020 (File No. 001-31403, Form 10-Q dated August 4, 2020, Exhibit 3.5).
3-14	Potomac Electric Power Company Restated Articles of Incorporation and Articles of Restatement of (as filed in the District of Columbia) (File No. 001-31403, Form 10-Q dated May 5, 2006, Exhibit 3.1).
3-15	Potomac Electric Power Company Restated Articles of Incorporation and Articles of Restatement of (as filed in Virginia) (File No. 001-01072, Form 10-Q dated November 4, 2011, Exhibit 3.3).
3-16	Delmarva Power & Light Company Articles of Restatement of Certificate and Articles of Incorporation (filed in Delaware and Virginia 02/22/07) (File No. 001-01405, Form 10-K dated March 1, 2007, Exhibit 3.3).
3-17	Atlantic City Electric Company Restated Certificate of Incorporation (filed in New Jersey on August 9, 2002) (File No. 001-03559, Amendment No. 1 to Form U5B dated February 13, 2003, Exhibit B.8.1).
3-18	Bylaws of Potomac Electric Power Company (File No. 001-01072, Form 10-Q dated May 5, 2006, Exhibit 3.2).
3-19	Bylaws of Delmarva Power & Light Company (File No. 001-01405, Form 10-Q dated May 9, 2005, Exhibit 3.2.1).
3-20	Bylaws of Atlantic City Electric Company (File No. 001-03559, Form 10-Q dated May 9, 2005, Exhibit 3.2.2).

Exhibit No.	Description
4-1	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank National Association, as current successor trustee), (Registration No. 2-2281, Exhibit B-1).[a]
4-1-1	Supplemental Indentures to PECO Energy Company's First and Refunding Mortgage:

Dated as of	File Reference	Exhibit No.
December 1, 1941	2-4863[a]	B-1(h)
April 15, 2004	000-16844, Form 10-Q dated September 30, 2004	4-1-1
September 15, 2006	000-16844, Form 8-K dated September 25, 2006	4.1
March 1, 2007	000-16844, Form 8-K dated March 19, 2007	4.1
September 1, 2012	000-16844, Form 8-K dated September 17, 2012	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
September 1, 2014	000-16844, Form 8-K dated September 15, 2014	4.1
September 15, 2015	000-16844, Form 8-K dated October 5, 2015	4.1
September 1, 2016	000-16844, Form 8-K dated September 21, 2016	4.1
September 1, 2017	000-16844, Form 8-K dated September 18, 2017	4.1
February 1, 2018	000-16844, Form 8-K dated February 23, 2018	4.1
September 1, 2018	000-16844, Form 8-K dated September 11, 2018	4.1
August 15, 2019	000-16844, Form 8-K dated September 10, 2019	4.1
June 1, 2020	000-16844, Form 8-K dated June 8, 2020	4.1

Exhibit No.	Description
4-2	Exelon Corporation Direct Stock Purchase Plan (Registration Statement No. 333-206474, Form S-3, Prospectus).
4-3	Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944. (Registration No. 2-60201, Form S-7, Exhibit 2-1).[a]

Exhibit No.	Description
4-3-1	Supplemental Indentures to Commonwealth Edison Company Mortgage.

Dated as of	File Reference	Exhibit No.
January 13, 2003	001-01839, Form 8-K dated February 13, 2003	4-4
February 22, 2006	001-01839, Form 8-K dated March 6, 2006	4.1
August 1, 2006	001-01839, Form 8-K dated August 28, 2006	4.1
September 15, 2006	001-01839, Form 8-K dated October 2, 2006	4.1
March 1, 2007	001-01839, Form 8-K dated March 23, 2007	4.1
August 30, 2007	001-01839, Form 8-K dated September 10, 2007	4.1
December 20, 2007	001-01839, Form 8-K dated January 16, 2008	4.1
March 10, 2008	001-01839, Form 8-K dated March 27, 2008	4.1
July 12, 2010	001-01839, Form 8-K dated August 2, 2010	4.1
August 22, 2011	001-01839, Form 8-K dated September 7, 2011	4.1
September 17, 2012	001-01839, Form 8-K dated October 1, 2012	4.1
August 1, 2013	001-01839, Form 8-K dated August 19, 2013	4.1
January 2, 2014	001-01839, Form 8-K dated January 10, 2014	4.1
October 28, 2014	001-01839, Form 8-K dated November 10, 2014	4.1
February 18, 2015	001-01839, Form 8-K dated March 2, 2015	4.1
November 4, 2015	001-01839, Form 8-K dated November 19, 2015	4.1
June 15, 2016	001-01839, Form 8-K dated June 27, 2016	4.1
August 9, 2017	001-01839, Form 8-K dated August 23, 2017	4.1

Dated as of	**File Reference**	**Exhibit No.**
February 6, 2018	001-01839, Form 8-K dated February 20, 2018	4.1
July 26, 2018	001-01839, Form 8-K dated August 14, 2018	4.1
February 7, 2019	001-01839, Form 8-K dated February 19, 2019	4.1
October 29, 2019	001-01839, Form 8-K dated November 12, 2019	4.1
February 10, 2020	001-01839, Form 8-K dated February 10, 2020	4.1

Exhibit No.	**Description**
4-4	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee (File No. 001-01839, Form 10-K dated April 1, 2002, Exhibit 4.4.2).
4-5	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual trustee (File No. 001-01839, Form 10-K dated March 29, 1996, Exhibit 4.29).
4-6	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (File No. 000-16844, Form 10-Q dated July 30, 2003, Exhibit 4.1).
4-7	Form of 4.25% Senior Note due 2022 issued by Exelon Generation Company, LLC. (File No. 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1).
4-8	Form of 5.60% Senior Note due 2042 issued by Exelon Generation Company, LLC. (File No. 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2).
4-9	Form of 2.80% Senior Note due 2022 issued by Baltimore Gas and Electric Company. (File No. 001-01910, Form 8-K dated August 17, 2012, Exhibit 4.1).
4-10	Form of 3.35% Senior Note due 2023 Baltimore Gas and Electric Company. (File No. 001-01910, Form 8-K dated June 17, 2013, Exhibit 4.1).
4-11	Form of 6.000% Senior Notes due 2033 issued by Exelon Generation Company, LLC (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1).
4-12	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank National Association, as Trustee, dated as of June 24, 2003 (File No. 000-16844, Form 10-Q dated July 30, 2003, Exhibit 4.2).
4-13	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust National Association, as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003 (File No. 000-16844, Form 10-Q dated July 30, 2003, Exhibit 4.3).
4-14	Indenture dated May 1, 2001 between Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 001-16169, Form 10-Q dated July 26, 2005, Exhibit 4.10).
4-15	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation (File No. 001-16169, Form 8-K dated June 9, 2005, Exhibit 99.3).

Exhibit No.	Description
4-16	Indenture dated as of September 28, 2007 from Exelon Generation Company, LLC to U.S. Bank National Association, as trustee (File No. 333-85496, Form 8-K dated September 28, 2007, Exhibit 4.1).
4-17	Form of 6.25% Exelon Generation Company, LLC Senior Note due 2039 (File No. 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.2).
4-18	Form of 4.00% Exelon Generation Company, LLC Senior Note due 2020 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.1).
4-19	Form of 5.75% Exelon Generation Company, LLC Senior Note due 2041 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.2).
4-20	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (File No. 333-75217, Registration Statement on Form S-3 dated March 29, 1999, Exhibit 4(a)).
4-21	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (File No. 333-102723, Registration Statement on Form S-3 dated January 24, 2003, Exhibit 4(b)).
4-22	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (File No. 333-135991, Registration Statement on Form S-3 dated July 24, 2006, Exhibit 4(a)).
4-23	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (File No. 001-12869, Form 8-K dated June 30, 2008, Exhibit 4(a)).
4-24	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (File No. 001-12869, Form 10-Q dated August 11, 2008, Exhibit 4(a)).
4-25	Indenture, dated as of September 30, 2013, among Continental Wind, LLC, the guarantors party thereto and Wilmington Trust, National Association, as trustee (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit 4.1).
4-26	Indenture dated July 1, 1985, between Baltimore Gas and Electric Company and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, filed by Baltimore Gas and Electric Company, File No. 1-1910).[a]
4-27	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (File No. 333-135991, Registration Statement on Form S-3 dated July 24, 2006, Exhibit 4(b)).
4-28	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (File No. 001-01910, Form 8-K dated July 5, 2007, Exhibit 4.1).
4-29	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (File No. 001-01910, Form 10-Q dated November 6, 2009, Exhibit 4(b)).
4-30	Replacement Capital Covenant dated June 27, 2008. (File No. 001-12869, Form 8-K dated June 30, 2008, Exhibit No. 4(b)).

Exhibit No.	**Description**
4-31	Amendment to Replacement Capital Covenant, dated as of March 12, 2012, amending the Replacement Capital Covenant, dated as of June 27, 2008 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 99.4).
4-32	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (File No. 001-12869, Form 8-K dated December 14, 2010, Exhibit 4 (b)).
4-33	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (File No. 001-01910, Form 8-K dated November 16, 2011, Exhibit 4(b)).
4-34	Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1).
4-35-1	First Supplemental Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.2).
4-35-2	Form of 2.50% Notes due 2024 (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.2, Exhibit A).
4-35-3	Purchase Contract and Pledge Agreement, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.4).
4-35-4	Form of Remarketing Agreement (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.4, Exhibit P).
4-35-5	Form of Corporate Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.4, Exhibit A).
4-35-6	Form of Treasury Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.4, Exhibit B).
4-36	Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 001-16169, Form 8-K dated June 11, 2015, Exhibit 4.1).
4-36-1	First Supplemental Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 001-16169, Form 8-K dated June 11, 2015, Exhibit 4.2).
4-36-2	Second Supplemental Indenture, dated as of December 2, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 001-16169, Form 8-K dated December 2, 2015, Exhibit 4.1).
4-37	Form of Conversion Supplemental Indenture, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 4.1).
4-38	Third Supplemental Indenture, dated as of April 7, 2016, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee (File No. 001-16169, Form 8-K dated April 7, 2016, Exhibit 4.2).
4-39	Mortgage and Deed of Trust, dated July 1, 1936, of Potomac Electric Power Company to The Bank of New York Mellon as successor trustee, securing First Mortgage Bonds of Potomac Electric Power Company, and Supplemental Indenture dated July 1, 1936 (File No. 2-2232, Registration Statement dated June 19, 1936, Exhibit B-4).(a)

Exhibit No.	Description
4-39-1	Supplemental Indentures to Potomac Electric Power Company Mortgage.

Dated as of	File Reference	Exhibit No.
December 10, 1939	Form 8-K dated January 3, 1940[(a)]	B
March 16, 2004	001-01072, Form 8-K dated March 23, 2004	4.3
May 24, 2005	001-01072, Form 8-K dated May 26, 2005	4.2
November 13, 2007	001-01072, Form 8-K dated November 15, 2007	4.2
March 24, 2008	001-01072, Form 8-K dated March 28, 2008	4.1
December 3, 2008	001-01072, Form 8-K dated December 8, 2008	4.2
March 28, 2012	001-01072, Form 8-K dated March 29, 2012	4.2
March 11, 2013	001-01072, Form 8-K dated March 12, 2013	4.2
November 14, 2013	001-01072, Form 8-K dated November 15, 2013	4.2
March 11, 2014	001-01072, Form 8-K dated March 12, 2014	4.2
March 9, 2015	001-01072, Form 8-K dated March 10, 2015	4.3
May 15, 2017	001-01072, Form 8-K dated May 22, 2017	4.2
June 1, 2018	001-01072, Form 8-K dated June 21, 2018	4.2
May 2, 2019	001-01072, Form 8-K dated June 13, 2019	4.2
February 12, 2020	001-01072, Form 8-K dated February 25, 2020	4.2

Exhibit No.	Description
4-40	Indenture, dated as of July 28, 1989, between Potomac Electric Power Company and The Bank of New York Mellon, Trustee, with respect to Medium-Term Note Program (File No. 001-01072, Form 8-K dated June 21, 1990, Exhibit 4).(a)
4-41	Senior Note Indenture, dated November 17, 2003 between Potomac Electric Power Company and The Bank of New York Mellon (File No. 001-01072, Form 8-K dated November 21, 2003, Exhibit 4.2).
4-41-1	Supplemental Indenture, dated March 31, 2008, to Senior Note Indenture between Potomac Electric Power Company and The Bank of New York Mellon (File No. 001-01072, Form 10-K dated March 2, 2009, Exhibit 4.3).

Exhibit No.	Description
4-42	Mortgage and Deed of Trust of Delaware Power & Light Company to The Bank of New York Mellon (ultimate successor to the New York Trust Company), as trustee, dated as of October 1, 1943, and copies of the First through Sixty-Eighth Supplemental Indentures thereto (File No. 33-1763, Registration Statement dated November 27, 1985, Exhibit 4-A)[(a)]
4-42-1	Supplemental Indentures to Delmarva Power & Light Company Mortgage.

Dated as of	File Reference	Exhibit No.
October 1, 1993	33-53855, Registration Statement dated January 30, 1995[(a)]	4-L
October 1, 1994	33-53855, Registration Statement dated January 30, 1995[(a)]	4-N
January 1, 1997	001-01405, Form 10-K dated February 24, 2012	4.4
November 7, 2013	001-01405, Form 8-K dated November 8, 2013	4.2
June 2, 2014	001-01405, Form 8-K dated June 3, 2014	4.3
May 4, 2015	001-01405, Form 8-K dated May 5, 2015	4.2
December 5, 2016	001-01405, Form 8-K dated December 12, 2016	4.2
April 5, 2017	001-01405, Form 10-Q dated May 3, 2017	4.5
April 3, 2018	000-01405, Form 10-Q dated May 2, 2018	4.3
June 1, 2018	000-01405, Form 8-K dated June 21, 2018	4.2
April 3, 2019	001-01405, Form 10-Q dated May 2, 2019	4.2
May 2, 2019	001-01405, Form 8-K dated December 12, 2019	4.2
March 18, 2020	001-01405, Form 10-Q dated May 8, 2020	4.4
June 1, 2020	001-01405, Form 8-K dated June 9, 2020	4.4

Exhibit No.	Description
4-43	Indenture between Delmarva Power & Light Company and The Bank of New York Mellon Trust Company, N.A. (ultimate successor to Manufacturers Hanover Trust Company), as trustee, dated as of November 1, 1988 (File No. 33-46892, Registration Statement dated April 1, 1992, Exhibit 4-G).[(a)]
4-44	Mortgage and Deed of Trust, dated January 15, 1937, between Atlantic City Electric Company and The Bank of New York Mellon (formerly Irving Trust Company), as trustee (File No. 2-66280, Registration Statement dated December 21, 1979, Exhibit 2(a)).[(a)]
4-44-1	Supplemental Indentures to Atlantic City Electric Company Mortgage.

Dated as of	File Reference	Exhibit No.
June 1, 1949	2-66280, Registration Statement dated December 21, 1979[(a)]	2(b)
March 1, 1991	Form 10-K dated March 28, 1991[(a)]	4(d)(1)
April 1, 2004	001-03559, Form 8-K dated April 6, 2004	4.3
March 8, 2006	001-03559, Form 8-K dated March 17, 2006	4
March 29, 2011	001-03559, Form 8-K dated April 1, 2011	4.2
August 18, 2014	001-03559, Form 8-K dated August 19, 2014	4.2
December 1, 2015	001-03559, Form 8-K dated December 2, 2015	4.2
October 9, 2018	001-03559, Form 8-K dated October 16, 2018	4.1
May 2, 2019	001-03559, Form 8-K dated May 21, 2019	4.3
June 1, 2020	001-03559, Form 8-K dated June 9, 2020	4.2

Exhibit No.	Description
4-45	Indenture, dated as of March 1, 1997, between Atlantic City Electric Company and The Bank of New York Mellon, as trustee (File No. 001-03559, Form 8-K dated March 24, 1997, Exhibit 4.2).
4-46	Senior Note Indenture, dated as of April 1, 2004, between Atlantic City Electric Company and The Bank of New York Mellon, as trustee (File No. 001-03559, Form 8-K dated April 6, 2004, Exhibit 4.2).
4-47	Indenture, dated as of December 19, 2002 between Atlantic City Electric Transition Funding LLC and The Bank of New York Mellon, as trustee (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 4.1).
4-48	2002-1 Series Supplement, dated as of December 19, 2002 between Atlantic City Electric Transition Funding LLC and The Bank of New York Mellon, as trustee (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 4.2).

Exhibit No.	Description
4-49	2003-1 Series Supplement, dated as of December 23, 2003 between Atlantic City Electric Transition Funding LLC and The Bank of New York Mellon, as trustee (File No. 333-59558, Form 8-K dated December 23, 2003, Exhibit 4.2).
4-50	Indenture, dated September 6, 2002, between Pepco Holdings, Inc. and The Bank of New York Mellon, as trustee (File No. 333-100478, Registration Statement on Form S-3 dated October 10, 2002, Exhibit 4.03).
4-51	Corporate Commercial Paper Master Note (File No. 001-31403, Form 10-K dated February 24, 2012, Exhibit 4.13).
4-52	Pepco Holdings, Inc. Certificate of Series A Non-Voting Non-Convertible Preferred Stock (File No. 001-31403, Form 8-K dated April 30, 2014, Exhibit 3.1).
4-53	Form of 2.400% notes due 2026 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.1).
4-54	Form of 3.500% notes due 2046 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.2).
4-55	Form of Exelon Generation Company, LLC 2.950% senior notes due 2020 (File No. 333-85496, Form 8-K dated March 10, 2017, Exhibit 4.1).
4-56	Form of Exelon Generation Company, LLC 3.400% notes due 2022 (File No. 333-85496, Form 8-K dated March 10, 2017, Exhibit 4.2).
4-57	Second Supplemental Indenture, dated April 3, 2017, between Exelon and The Bank of New York Mellon Trust Company, N.A., as trustee, to that certain Indenture (For Unsecured Subordinated Debt Securities), dated June 17, 2014 (File No. 001-16169, Form 8-K dated April 4, 2017, Exhibit 4.3).
4-58	Form of Exelon Corporation 3.497% junior subordinated notes due 2022 (File No. 001-16169, Form 8-K dated April 4, 2017, Exhibit 4.4).
4-59	Form of First Mortgage Bond, 4.15% Series due March 15, 2043 (File No. 001-01072, Form 8-K dated May 22, 2017, Exhibit 4.2).
4-60	BGE Form of 3.750% notes due 2047 (File No. 001-01910, Form 8-K dated August 24, 2017, Exhibit 4.1).
4-61	Exempt Facilities Loan Agreement dated as of June 1, 2019 between the Maryland Economic Development Corporation and Potomac Electric Power Company (File No. 001-01072, Form 8-K dated June 27, 2019, Exhibit 4.1).
4-62	Indenture, dated as of September 1, 2019, between Baltimore Gas and Electric Company and U.S. Bank National Association, as trustee (File No. 001-01910, Form 8-K dated September 12, 2019, Exhibit 4.1).
4-63	Description of Exelon Securities (File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 4.63).
4-64	Description of PECO Securities (File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 4.64).
4-65	Description of ComEd Securities (File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 4.65).
4-66	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. 001-16169, Form 8-K dated April 1, 2020, Exhibit 4.2).

Exhibit No.	Description
4-67	Form of Exelon Generation Company LLC 3.250% Senior Notes due 2025 (File No. 333-85496, Form 8-K dated May 15, 2020, Exhibit 4.1).
4-68	Pollution Control Facilities Loan Agreement, dated as of June 1, 2020, between The Pollution Control Financing Authority of Salem County and Atlantic City Electric (File No. 001-03559, Form 8-K dated June 2, 2020, Exhibit 4.1).
4-69	Gas Facilities Loan Agreement, dated as of July 1, 2020, between The Delaware Economic Development Authority and Delmarva Power (File No. 001-01405, Form 8-K dated July 1, 2020, Exhibit 4.1).
10-1	Exelon Corporation Non-Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective April 28, 2020). (File No. 001-16169, Form 10-Q dated August 4, 2020, Exhibit 10.1).
10-2	Form of Exelon Corporation Unfunded Deferred Compensation Plan for Directors (as amended and restated Effective March 12, 2012) * (File No. 001-16169, Form 10-K dated February 10, 2016, Exhibit 10.3).
10-3	Form of Restricted Stock Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, Form 10-Q dated October 31, 2019, Exhibit 10.2).
10-4	Unicom Corporation Deferred Compensation Unit Plan, as amended (File No. 001-11375, Form 10-K dated March 29, 1996, Exhibit 10.12).
10-5	Amendment Number One to the Unicom Corporation Deferred Compensation Unit Plan, as amended January 1, 2008 * (File No. 001-16169, Form 10-K dated February 6, 2009, Exhibit 10.16).
10-6	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, Form 10-K dated February 6, 2009, Exhibit 10.19).
10-7	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009) (File No. 000-16844, Form 10-K dated February 6, 2009, Exhibit 10.20).
10-8	Exelon Corporation Annual Incentive Plan for Senior Executives (As Amended Effective January 1, 2014 * (File No. 001-16169, Proxy Statement dated April 1, 2014, Appendix A).
10-9	Exelon Corporation Employee Stock Purchase Plan, as amended and restated effective September 25, 2019 (File No. 001-16169, Form 10-Q dated October 31, 2019, Exhibit 10.3).
10-10	Exelon Corporation 2006 Long-Term Incentive Plan (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex H).
10-11	Form of Stock Option Grant Instrument under the Exelon Corporation 2006 Long-Term Incentive Plan (File No. 001-16169, Form 8-K dated January 27, 2006, Exhibit 99.2).
10-12	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries, as amended and restated effective September 25, 2019 (File No. 001-16169, Form 10-Q dated October 31, 2019, Exhibit 10.4).
10-13	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2020) * (File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 10.13).
10-14	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 * (File No. 001-16169, Form 10-K dated February 13, 2007, Exhibit 10.52).
10-15	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 * (File No. 001-16169, Form 10-K dated February 13, 2007, Exhibit 10.53).

Exhibit No.	Description
10-16	Amendment Number One to the Exelon Corporation 2006 Long-Term Incentive Plan, Effective December 4, 2006 (File No. 001-16169, Form 10-K dated February 13, 2007, Exhibit 10.54).
10-17	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005) (File No. 001-16169, Form 10-K dated February 13, 2007, Exhibit 10.56).
10-18	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective September 25, 2019) (File No. 001-16169, Form 10-Q dated October 31, 2019, Exhibit 10.5).
10-19	Restricted stock unit award agreement (File 001-16169, Form 8-K dated August 31, 2007, Exhibit 99.1).
10-20	Form of Exelon Corporation 2011 Long-Term Incentive Plan, as amended effective December 18, 2014. * (File No. 001-16169, Form 10-K dated February 10, 2016, Exhibit 10.34).
10-20-1	Form of Exelon Corporation Long-Term Incentive Program, as amended and restated as of January 1, 2020. * (File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 10.21).
10-20-2	Amendment Number Two to the Exelon Corporation 2011 Long-Term Incentive Plan (As Amended and Restated Effective January 21, 2014), Effective October 26, 2015. * (File No. 001-16169, Form 10-K dated February 10, 2016, Exhibit 10.34.3).
10-21	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2020) (File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 10.21).
10-22	Credit Agreement for $500,000,000 dated as of March 23, 2011 between Exelon Corporation and Various Financial Institutions (File No. 001-16169, Form 8-K dated March 23, 2011, Exhibit 99.1).
10-23	Credit Agreement for $5,300,000,000 dated as of March 23, 2011 between Exelon Generation Company, LLC and Various Financial Institutions (File No. 333-85496, Form 8-K dated March 23, 2011, Exhibit 99.2).
10-24	Credit Agreement for $600,000,000 dated as of March 23, 2011 between PECO Energy Company and Various Financial Institutions (File No. 000-16844, Form 8-K dated March 23, 2011, Exhibit 99.3).
10-25	Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, Various Financial Institutions, as Lenders, and JP Morgan Chase Bank, N.A., as Administrative Agent (File No. 001-01839, Form 8-K dated March 28, 2012, Exhibit 99.1).
10-26	Amendment No. 3 to Credit Agreement dated as of March 23, 2011 among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated August 10, 2013, Exhibit 99.1).
10-27	Amendment No. 1 to Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-1839, Form 8-K dated August 10, 2013, Exhibit 99.2).
10-28	Amendment No. 1 to Credit Agreement, dated as of December 21, 2011, to the Credit Agreement dated as of March 23, 2011, among Exelon Generation Company, LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 4.6).
10-29	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. * (File No. 001-12869, Form 10-K dated February 27, 2009, Exhibit 10(b)).
10-30	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. * (File No. 001-12869, Form 10-K dated February 27, 2009, Exhibit 10(c)).

Exhibit No.	Description
10-31	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010. * (File No. 001-12869, Form 10-Q dated August 6, 2010, Exhibit 10(b)).
10-32	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. * (File No. 001-12869, Form 10-K dated February 27, 2009, Exhibit 10(e)).
10-33	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. * (File No. 001-12869, Form 10-K dated February 27, 2009, Exhibit 10(f)).
10-34	Constellation Energy Group, Inc. Executive Supplemental Benefits Plan, as amended and restated. * (File No. 001-12869, Form 10-Q dated August 11, 2008, Exhibit No. 10(a)).
10-35	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan. * (File No. 001-12869, Form 8-K dated June 4, 2010, Exhibit 10.1).
10-36	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (File No. 001-12869, Form 8-K dated November 12, 2009, Exhibit 10.1).
10-37	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (File No. 001-12869, Form 10-K dated March 3, 2011, Exhibit 10(s)).
10-38	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (File No. 001-12869, Form 10-K dated March 3, 2011, Exhibit 10(t)).
10-39	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (File No. 001-12869, Form 8-K dated November 3, 2010, Exhibit 10.1).
10-40	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (File No. 001-12869, Form 8-K dated November 3, 2010, Exhibit 10.2).
10-41	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (File No. 001-12869, Form 8-K dated January 19, 2012, Exhibit 10.1).
10-42-1	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.1).
10-42-2	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.2).
10-42-3	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.3).
10-42-4	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.4).

Exhibit No.	Description
10-43	Bondable Transition Property Sale Agreement, dated as of December 19, 2002, between ACE Funding and ACE (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 10.1).
10-44	Bondable Transition Property Servicing Agreement, dated as of December 19, 2002, between ACE Funding and ACE (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 10.2).
10-45	Purchase Agreement, dated as of April 20, 2010, by and among Pepco Holdings, Inc., Conectiv, LLC, Conectiv Energy Holding Company, LLC and New Development Holdings, LLC (File No. 001-31403, Form 8-K dated July 8, 2010, Exhibit 2.1).
10-46	Purchase Agreement, dated March 9, 2015, among Potomac Electric Power Company and BNY Mellon Capital Markets, LLC, Morgan Stanley & Co. LLC, and RBS Securities Inc., as representatives of the several underwriters named therein (File No. 001-01072, Form 8-K dated March 10, 2015, Exhibit 1.1).
10-47	Purchase Agreement, May 4, 2015, among Delmarva Power & Light Company and J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, and Scotia Capital (USA) Inc., as representatives of the several underwriters named therein (File No. 001-01405, Form 8-K dated May 5, 2015, Exhibit 1.1).
10-48	Bond Purchase Agreement, dated December 1, 2015, among Atlantic City Electric Company and the purchasers signatory thereto (File No. 001-03559, Form 8-K dated December 2, 2015, Exhibit 1.1).
10-49	$300,000,000 Term Loan Agreement by and among PHI, The Bank of Nova Scotia, as Administrative Agent, and the lenders party thereto, dated July 30, 2015 (File No. 001-31403, Form 8-K dated July 30, 2015, Exhibit 10).
10-50	First Amendment to Term Loan Agreement, dated as of October 29, 2015, by and among PHI, The Bank of Nova Scotia, as Administrative Agent, and the lenders party thereto (File No. 001-31403, Form 8-K dated October 29, 2015, Exhibit 10.2).
10-51	$500,000,000 Term Loan Agreement by and among PHI, The Bank of Nova Scotia, as Administrative Agent, and the lenders party thereto, dated January 13, 2016 (File No. 001-31403, Form 8-K dated January 14, 2016, Exhibit 10).
10-52	Second Amended and Restated Credit Agreement, dated as of August 1, 2011, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the lenders party thereto, Wells Fargo Bank, National Association, as agent, issuer and swingline lender, Bank of America, N.A., as syndication agent and issuer, The Royal Bank of Scotland plc and Citicorp USA, Inc., as co-documentation agents, Wells Fargo Securities, LLC and Merrill Lynch, Pierce, Fenner and Smith Incorporated, as active joint lead arrangers and joint book runners, and Citigroup Global Markets Inc. and RBS Securities, Inc. as passive joint lead arrangers and joint book runners (File No. 001-31403, Form 10-Q dated August 3, 2011, Exhibit 10.1).
10-52-1	First Amendment, dated as of August 2, 2012, to Second Amended and Restated Credit Agreement, dated as of August 1, 2011, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions party thereto, Wells Fargo Bank, National Association, as agent, issuer of letters of credit and swingline lender, Bank of America, N.A., as syndication agent and issuer of letters of credit, and The Royal Bank of Scotland plc and Citibank, N.A., as co-documentation agents (File No. 001-31403, Form 10-K dated March 1, 2013, Exhibit 10.25.1).
10-52-2	Amendment and Consent to Second Amended and Restated Credit Agreement, dated as of May 20, 2014, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association (File No. 001-31403, Form 8-K dated May 20, 2014, Exhibit 10.1).

Exhibit No.	Description
10-52-3	Third Amendment to Second Amended and Restated Credit Agreement, dated as of May 1, 2015, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association (File No. 001-31403, Form 8-K dated May 1, 2015, Exhibit 10.1).
10-52-4	Consent, dated as of October 29, 2015, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association (File No. 001-31403, Form 8-K dated October 29, 2015, Exhibit 10.1).
10-53	Asset Purchase and Sale Agreement for Generating Plants and Related Assets, dated as of June 7, 2000, by and between Pepco and Southern Energy, Inc. (File No. 001-01072, Form 8-K dated June 13, 2000, Exhibit 10).
10-53-1	Amendment No. 1 to the Asset Purchase and Sale Agreement for Generating Plants and Related Assets, dated September 18, 2000, by and between Potomac Electric Power Company and Southern Energy, Inc. (File No. 001-01072, Form 8-K dated December 19, 2000, Exhibit 10.1).
10-53-2	Amendment No. 2 to the Asset Purchase and Sale Agreement for Generating Plants and Related Assets, dated December 19, 2000, by and between Potomac Electric Power Company and Southern Energy, Inc. (File No. 001-01072, Form 8-K dated December 19, 2000, Exhibit 10.2).
10-54	First Amendment to Loan Agreement, by and between Pepco Holdings LLC and The Bank of Nova Scotia, as administrative agent and lender, dated March 28, 2016 (File No. 001-31403, Form 8-K dated March 28, 2016, Exhibit 10).
10-55	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated May 27, 2016, Exhibit 99.1).
10-56	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Generation Company, LLC, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 333-85496, Form 8-K dated May 27, 2016, Exhibit 99.2).
10-57	Amendment No. 4 to Credit Agreement, dated as of March 23, 2011, among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 333-85496, Form 8-K dated May 27, 2016, Exhibit 99.3).
10-58	Amendment No. 6 to Credit Agreement, dated as of March 23, 2011, among PECO Energy Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 000-16844, Form 8-K dated May 27, 2016, Exhibit 99.4).
10-59	Amendment No. 5 to Credit Agreement, dated as of March 23, 2011, among Baltimore Gas and Electric Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-01910, Form 8-K dated May 27, 2016, Exhibit 99.5).
10-60	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of August 1, 2011, among Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, as Borrowers, the various financial institutions named therein, as Lenders, and Wells Fargo Bank, National Association, as Administrative Agent (File No. 001-31403, Form 8-K dated May 27, 2016, Exhibit 99.6).

Exhibit No.	Description
10-61	2016 Form of Exelon Corporation Change in Control Agreement (File No. 001-16169, Form 10-Q dated October 26, 2016, Exhibit 10.1).
10-62	Execution Version-ZEC Standard Contract by and between the NYSERDA and Nine Mile Point Nuclear Station, LLC dated Nov. 18, 2016 (File No. 001-16169, Form 8-K dated November 18, 2016, Exhibit 10.1).
10-63	Execution Version-ZEC Standard Contract by and between the NYSERDA and R. E. Ginna Nuclear Power Plant, LLC dated Nov. 18, 2016 (File No. 001-16169, Form 8-K dated November 18, 2016, Exhibit 10.2).
10-64	Credit Agreement, dated as of November 28, 2017, as thereafter amended and conformed among ExGen Renewables IV, LLC, ExGen Renewables IV Holding, LLC, Morgan Stanley Senior Funding, Inc. as administrative agent, Wilmington Trust, National Association, as depository bank and collateral agent, and the lenders and other agents party thereto. (Certain portions of this exhibit have been omitted by redacting a portion of text, as indicated by asterisks in the text. This exhibit has been filed separately with the U.S. Securities and Exchange Commission pursuant to a request for confidential treatment.) (File No. 001-16169, Form 10-K dated February 9, 2018, Exhibit 10.94).
10-65	Purchase Agreement, dated June 8, 2018 among Delmarva Power & Light Company and the purchasers signatory thereto (File No. 001-01405, Form 8-K dated June 21, 2018, Exhibit 1.1).
10-66	Purchase Agreement, dated June 8, 2018, among Potomac Electric Power Company and the purchasers signatory thereto (File No. 001-01072, Form 8-K dated June 21, 2018, Exhibit 1.1).
10-67	Letter Agreement, dated May 7, 2018, between Exelon Corporation and Denis P. O'Brien (File No. 001-16169, Form 10-Q dated August 2, 2018, Exhibit 10.3).
10-68	Letter Agreement, dated May 7, 2018, between Exelon Corporation and Jonathan W. Thayer (File No. 001-16169, Form 10-Q dated August 2, 2018, Exhibit 10.4).
10.69	Exelon Corporation 2020 Long-Term Incentive Plan (Effective April 28, 2020) (File No. 001-16169, Proxy Statement dated March 18, 2020, Appendix A).
10.70	Exelon Corporation 2020 Long-Term Incentive Plan Prospectus, dated May 27, 2020 (File No. 001-16169, Form 10-Q dated August 4, 2020, Exhibit 10.3).
10.71	Form of Restricted Stock Unit Award Notice and Agreement under the Exelon Corporation 2020 Long-Term Incentive Plan (File No. 001-16169, Form 10-Q dated August 4, 2020, Exhibit 10.4).
10.72	Form of Performance Share Award Notice and Agreement under the Exelon Corporation 2020 Long-Term Incentive Plan (File No. 001-16169, Form 10-Q dated August 4, 2020, Exhibit 10.5).
10.73	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. 001-16169, Form 8-K dated April 9, 2020, Exhibit 10.1).
10.74	Letter Agreement, dated Jun 4, 2020, between Exelon Corporation and William A. Von Hoene, Jr.**
10.75	Deferred Prosecution Agreement, dated July 17, 2020, between Commonwealth Edison Company and the U.S. Department of Justice and the U.S. Attorney for the Northern District of Illinois (File No. 001-16169, Form 8-K dated July 17, 2020, Exhibit 10.1).
10.76	Credit Agreement, among ExGen Renewables IV, LLC, the lenders party thereto, Jefferies Finance LLC, as administrative agent, and Wilmington Trust, National Association, as depositary ban and collateral agent, dated December 15, 2020 (File No. 333-85496, Form 8-K dated December 15, 2020, Exhibit 1.1).

Exhibit No.	Description
14	Exelon Code of Conduct, as amended March 12, 2012 (File No. 1-16169, Form 8-K dated March 14, 2012, Exhibit No. 14-1).
	Subsidiaries
21-1	Exelon Corporation
21-2	Exelon Generation Company, LLC
21-3	Commonwealth Edison Company
21-4	PECO Energy Company
21-5	Baltimore Gas and Electric Company
21-6	Pepco Holdings LLC
21-7	Potomac Electric Power Company
21-8	Delmarva Power & Light Company
21-9	Atlantic City Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Exelon Generation Company, LLC
23-3	Commonwealth Edison Company
23-4	PECO Energy Company
23-5	Baltimore Gas and Electric Company
23-6	Potomac Electric Power Company
23-7	Delmarva Power & Light Company
23-8	Atlantic City Electric Company
	Power of Attorney (Exelon Corporation)
24-1	Anthony K. Anderson
24-2	Ann C. Berzin
24-3	Laurie Brlas
24-4	Christopher M. Crane
24-5	Yves C. de Balmann
24-6	Nicholas DeBenedictis
24-7	Linda P. Jojo
24-8	Paul Joskow
24-9	Robert J. Lawless
24-10	Marjorie Rodgers Cheshire
24-11	Reserved.
24-12	Mayo A. Shattuck III
24-13	Reserved.

Exhibit No.	Description
24-14	John F. Young
24-15	John Richardson
	Power of Attorney (Commonwealth Edison Company)
24-16	James W. Compton
24-17	Christopher M. Crane
24-18	A. Steven Crown
24-19	Nicholas DeBenedictis
24-20	Joseph Dominguez
24-21	Peter V. Fazio, Jr.
24-22	Michael H. Moskow
24-23	Calvin G. Butler
24-24	Reserved.
	Power of Attorney (PECO Energy Company)
24-25	Christopher M. Crane
24-26	Reserved.
24-27	Nicholas DeBenedictis
24-28	Nelson A. Diaz
24-29	John S. Grady
24-30	Rosemarie B. Greco
24-31	Michael A. Innocenzo
24-32	Charisse R. Lillie
24-33	Calvin G. Butler
	Power of Attorney (Baltimore Gas and Electric Company)
24-34	Ann C. Berzin
24-35	Carim V. Khouzami
24-36	Christopher M. Crane
24-37	Michael E. Cryor
24-38	James R. Curtiss
24-39	Joseph Haskins, Jr.
24-40	Calvin G. Butler
24-41	Michael D. Sullivan
24-42	Maria Harris Tildon
	Power of Attorney (Pepco Holdings LLC)
24-43	Christopher M. Crane

Exhibit No.	Description
24-44	Linda W. Cropp
24-45	Michael E. Cryor
24-46	Ernest Dianastasis
24-47	Debra P. DiLorenzo
24-48	Calvin G. Butler
24-49	David M. Velazquez
	Power of Attorney (Potomac Electric Power Company)
24-50	J. Tyler Anthony
24-51	Phillip S. Barnett
24-52	Christopher M. Crane
24-53	Melissa A. Lavinson
24-54	Kevin M. McGowan
24-55	Calvin G. Butler
24-56	David M. Velazquez
	Power of Attorney (Delmarva Power & Light Company)
24-57	Calvin G. Butler
24-58	David M. Velazquez
	Power of Attorney (Atlantic City Electric Company)
24-59	David M. Velazquez

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2020 filed by the following officers for the following registrants:

Exhibit No.	Description
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Joseph Nigro for Exelon Corporation
31-3	Filed by Christopher M. Crane for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Joseph Dominguez for Commonwealth Edison Company
31-6	Filed by Jeanne M. Jones for Commonwealth Edison Company
31-7	Filed by Michael A. Innocenzo for PECO Energy Company
31-8	Filed by Robert J. Stefani for PECO Energy Company
31-9	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
31-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
31-11	Filed by David M. Velazquez for Pepco Holdings LLC
31-12	Filed by Phillip S. Barnett for Pepco Holdings LLC

Exhibit No.	Description
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 as to the Annual Report on Form 10-K for the year ended December 31, 2020 filed by the following officers for the following registrants:

Exhibit No.	Description
32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Joseph Nigro for Exelon Corporation
32-3	Filed by Christopher M. Crane 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
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

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* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.
** Filed herewith.
(a) These filings are not available electronically on the SEC website as they were filed in paper previous to the electronic system that is currently in place.

ITEM 16. FORM 10-K SUMMARY

All Registrants

Registrants may voluntarily include a summary of information required by Form 10-K under this Item 16. The Registrants have elected not to include such summary information.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Chicago and State of Illinois on the 24th day of February, 2021.

EXELON CORPORATION

By: /s/ CHRISTOPHER M. CRANE
Name: Christopher M. Crane
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2021.

Signature	Title
/s/ CHRISTOPHER M. CRANE Christopher M. Crane	President, Chief Executive Officer (Principal Executive Officer) and Director
/s/ JOSEPH NIGRO Joseph Nigro	Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ FABIAN E. SOUZA Fabian E. Souza	Senior Vice President and Corporate Controller (Principal Accounting Officer)

This annual report has also been signed below by Gayle E. Littleton, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Anthony K. Anderson
Ann C. Berzin
Laurie Brlas
Yves C. de Balmann
Nicholas DeBenedictis
Linda P. Jojo
Paul L. Joskow
Robert J. Lawless
John M. Richardson
Marjorie Rodgers Cheshire
Mayo A. Shattuck III
John F. Young

By: /s/ GAYLE E. LITTLETON February 24, 2021
Name: Gayle E. Littleton

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Chicago and State of Illinois on the 24th day of February, 2021.

EXELON GENERATION COMPANY, LLC

By:	/s/ CHRISTOPHER M. CRANE
Name:	Christopher M. Crane
Title:	Principal Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2021.

Signature	Title
/s/ CHRISTOPHER M. CRANE Christopher M. Crane	Principal Executive Officer
/s/ BRYAN P. WRIGHT Bryan P. Wright	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ MATTHEW N. BAUER Matthew N. Bauer	Vice President and Controller (Principal Accounting Officer)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Chicago and State of Illinois on the 24th day of February, 2021.

COMMONWEALTH EDISON COMPANY

By:	/s/ JOSEPH DOMINGUEZ
Name:	Joseph Dominguez
Title:	Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2021.

Signature	Title
/s/ JOSEPH DOMINGUEZ Joseph Dominguez	Chief Executive Officer (Principal Executive Officer) and Director
/s/ JEANNE M. JONES Jeanne M. Jones	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ STEVEN J. CICHOCKI Steven J. Cichocki	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by Joseph Dominguez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Calvin G. Butler
James W. Compton
Christopher M. Crane
A. Steven Crown

Nicholas DeBenedictis
Peter V. Fazio, Jr.
Michael H. Moskow

By:	/s/ JOSEPH DOMINGUEZ	February 24, 2021
Name:	Joseph Dominguez	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Chicago and State of Illinois on the 24th day of February, 2021.

PECO ENERGY COMPANY

By: /s/ MICHAEL A. INNOCENZO
Name: Michael A. Innocenzo
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2021.

Signature	**Title**
/s/ MICHAEL A. INNOCENZO Michael A. Innocenzo	President, Chief Executive Officer (Principal Executive Officer) and Director
/s/ ROBERT J. STEFANI Robert J. Stefani	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ CAROLINE FULGINITI Caroline Fulginiti	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by Michael A. Innocenzo, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Calvin G. Butler
Christopher M. Crane
Nicholas DeBenedictis
Nelson A. Diaz
John S. Grady
Rosemarie B. Greco
Charisse R. Lillie

By: /s/ MICHAEL A. INNOCENZO — February 24, 2021
Name: Michael A. Innocenzo

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Chicago and State of Illinois on the 24th day of February, 2021.

BALTIMORE GAS AND ELECTRIC COMPANY

By:	/s/ CARIM V. KHOUZAMI
Name:	Carim V. Khouzami
Title:	Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2021.

Signature	Title
/s/ CARIM V. KHOUZAMI Carim V. Khouzami	Chief Executive Officer (Principal Executive Officer) and Director
/s/ DAVID M. VAHOS David M. Vahos	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JASON T. JONES Jason T. Jones	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by Carim V. Khouzami, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Ann C. Berzin
Calvin G. Butler
Christopher M. Crane
Michael E. Cryor
James R. Curtiss
Joseph Haskins, Jr.
Michael D. Sullivan
Maria Harris Tildon

By:	/s/ CARIM V. KHOUZAMI	February 24, 2021
Name:	Carim V. Khouzami	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Chicago and State of Illinois on the 24th day of February, 2021.

PEPCO HOLDINGS LLC

By:	/s/ DAVID M. VELAZQUEZ
Name:	David M. Velazquez
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2021.

Signature	Title
/s/ DAVID M. VELAZQUEZ David M. Velazquez	President, Chief Executive Officer (Principal Executive Officer), and Director
/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)

This annual report has also been signed below by David M. Velazquez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Calvin. G. Butler
Christopher M. Crane
Linda W. Cropp
Michael E. Cryor
Ernest Dianastasis
Debra P. DiLorenzo

By:	/s/ DAVID M. VELAZQUEZ	February 24, 2021
Name:	David M. Velazquez	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Chicago and State of Illinois on the 24th day of February, 2021.

POTOMAC ELECTRIC POWER COMPANY

By:	/s/ DAVID M. VELAZQUEZ
Name:	David M. Velazquez
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2021.

Signature	Title
/s/ DAVID M. VELAZQUEZ David M. Velazquez	President, Chief Executive Officer (Principal Executive Officer), and Director
/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)

This annual report has also been signed below by David M. Velazquez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

J. Tyler Anthony
Phillip S. Barnett
Calvin G. Butler
Christopher M. Crane
Melissa A. Lavinson
Kevin M. McGowan

By:	/s/ DAVID M. VELAZQUEZ	February 24, 2021
Name:	David M. Velazquez	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Chicago and State of Illinois on the 24th day of February, 2021.

DELMARVA POWER & LIGHT COMPANY

By:	/s/ DAVID M. VELAZQUEZ
Name:	David M. Velazquez
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2021.

Signature	Title
/s/ DAVID M. VELAZQUEZ David M. Velazquez	President, Chief Executive Officer (Principal Executive Officer), and Director
/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)

This annual report has also been signed below by David M. Velazquez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Calvin G. Butler

By:	/s/ DAVID M. VELAZQUEZ	February 24, 2021
Name:	David M. Velazquez	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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, in the City of Chicago and State of Illinois on the 24th day of February, 2021.

ATLANTIC CITY ELECTRIC COMPANY

By:	/s/ DAVID M. VELAZQUEZ
Name:	David M. Velazquez
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 24th day of February, 2021.

Signature	Title
/s/ DAVID M. VELAZQUEZ David M. Velazquez	President, Chief Executive Officer (Principal Executive Officer), and Director
/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)